Appendix A
Glossary of Terms

**AECO-C**: Alberta’s natural gas hub. A hub serves as a physical point of exchange and as a market in which buyers and sellers can meet either physically or via paper or electronic mechanisms.

**Alberta Interconnected Electric System (AIES)**: The system of interconnected transmission power lines and generators in Alberta.

**Alberta Internal Load (AIL)**: The total electricity consumption including behind-the-fence (BTF) load, the City of Medicine Hat and losses (transmission and distribution).

**Alternating current (AC)**: A current that flows alternately in one direction and then in the reverse direction. In North America, the standard for alternating current is 60 complete cycles each second. Cycles per second is also referred to as Hertz (Hz).

**Ancillary services**: Services necessary to support the transmission of energy from resources to loads while maintaining reliable operation of the transmission system in accordance with good utility practice.

**Available transfer capability (ATC)**: The amount of electricity that can flow on interties. This capability is an hourly value that fluctuates with system conditions.

**Baseload capacity/generation**: The generating equipment normally operated to serve loads on an around-the-clock basis.

**Behind-the-fence load (BTF) load**: Industrial load characterized by being served in whole, or in part, by on-site generation built on the host’s site.

**Biomass fuel**: A specific type of biomass used to produce synthetic fuels or that can be burned in its natural state to produce energy. Biomass fuels include wood waste, peat, manure, grain by-products and food processing wastes.

**Brownfield**: Land previously or currently used for industrial or certain commercial purposes.

**Bulk transmission system**: The integrated system of transmission lines and substations that delivers electric power from major generating stations to load centres. The bulk system, which generally includes 500 kilovolt (kV) and 240 kV transmission lines and substations, also delivers/receives power to and from adjacent control areas.

**Bus (busbar)**: Electrically conductive structures in a substation to which elements such as transformers or transmission lines are connected.
**Capability:** The maximum load that a generating unit, generating station or other electrical apparatus can carry under specified conditions for a given period of time without exceeding limits of temperature and stress.

**Capacitance:** The property of a system of conductors and dielectrics that permits the storage of electrically separated charges when potential differences exist between the conductors. A measure of the amount of electric charge stored (or separated) for a given electric potential.

**Capacitor/capacitor bank:** A static device (sometimes referred to as static capacitors) that introduces capacitive reactance into the power system. Capacitors are used to control voltages by eliminating the voltage drop in the system caused by inductive reactive loads. If connected between conductors or between conductors and ground, they are sometimes described as shunt capacitors. If connected in series with a transmission line, they are described as series capacitors.

**Capacity:** The amount of electric power delivered or required for a generator, turbine, transformer, transmission circuit, substation or system as rated by the manufacturer.

**Capacity factor:** The ratio of energy actually produced by a generator compared to the energy that could have been produced if the unit were operated at its rated output continuously.

**Carbon capture ready:** The infrastructure required to enable the capture of carbon dioxide and compress it to the pressure required for transporting to a storage location.

**Carbon offset:** A financial instrument representing a reduction in greenhouse gas (GHG) emissions.

**Circuit:** A conductor or a system of conductors through which electric current flows.

**Cleaner fuel standard:** The emission intensity requirements defined by Environment Canada for new facilities in the *Regulatory Framework for Air Emissions* (2008).

**Cogeneration:** The simultaneous production of electricity and another form of useful thermal energy used for industrial, commercial, heating or cooling purposes.

**Coincident demand:** Any demand that occurs simultaneously with any other demand (e.g., regional or peak demand).

**Combined cycle generation:** A system in which a gas turbine generates electricity and the waste heat is used to create steam to generate additional electricity using a steam turbine.

**Commercial operation:** Control of the loading of a generator is turned over to a system dispatcher.

**Commissioning:** The process by which a facility is tested and ultimately accepted for commercial operation.

**Compressed air energy storage (CAES):** A mechanical energy storage system involving the compression of air to be used later as an energy source.
Conductor: A metallic wire or combination of wires through which electric current is intended to flow.

Congestion: The condition under which transactions that market participants wish to undertake are constrained by conditions on the transmission grid.

Constraint: A restriction on a transmission system or segment of a transmission system that may limit the ability to transmit power between various locations.

Control area: A defined region of the electricity grid for which supply and demand are kept in balance by the control area’s system operator.

Converter station: A location where electric energy is converted to direct current (DC) from AC or vice versa.

Customer sectors: Types of electric load classified according to type of use. Four sectors commonly used are residential, commercial, farm and industrial.

Cutplane: An imaginary line that cuts across the transmission lines that connect two or more areas. The loading on these lines is summed together to measure the power flow across the cutplane.

Demand (electric): The volume of electric energy delivered to or by a system, part of a system, or piece of equipment at a given instant or averaged over any designated period of time.

Demand opportunity service (DOS): An opportunity transmission service with regulated rates for each level of interruption (seven minutes and one hour). Load customers pay the distribution transmission service (DTS) rate in accordance with the AESO’s tariff.

Demand-side management (DSM): Activities that occur on the demand (customer) side of the meter and are implemented by the customer directly or by load serving entities.

Demand transmission service (DTS): The service provided to loads for interconnection access to the Alberta transmission system.

Derate: A reduction in a generating unit’s or other piece of electric equipment's net capacity.

Direct current (DC): Current that flows continuously in the same direction (as opposed to AC). The current supplied from a battery is direct current.

Dispatch: The process by which a system operator directs the real-time operation of a supplier or a purchaser to cause a specified amount of electric energy to be provided to, or taken off, the system.

Distributed generation: Small-scale power sources typically connected to a distribution system at customer locations.

Distribution system: The portion of an electric system that is dedicated to delivering electric energy from the transmission system to an end-use customer.
**Distribution utility**: A regulated electric utility entity that constructs and maintains the distribution wires connecting the transmission grid to an end-use customer.

**Double circuit**: A line of supporting structures that carries two power circuits.

**Effective capacity**: The capacity of a generator that is available to serve peak load.

**Emission intensity**: The ratio of a specific emission (such as carbon dioxide) to a measure of energy output. For the electricity sector, emission intensity is usually expressed as emissions per megawatt hour (MWh) of electricity generated.

**End user**: A residential, farm, commercial or industrial customer in the electricity marketplace who buys electric power for their own consumption and not for resale.

**Gas turbine**: See simple cycle gas turbine.

**Generating facility**: A facility housing one or more generating units.

**Generating unit**: Any combination of an electrical generator physically connected to reactor(s), boiler(s), combustion or wind turbine(s) or other prime mover(s) and operated together to produce electric power.

**Generation reserve margin**: See reserve margin.

**Geothermal plant**: A plant in which the prime mover is a turbine driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the Earth.

**Gigawatt (GW)**: One billion watts.

**Gigawatt hour (GWh)**: One billion watt hours.

**Greenfield**: Land being considered for development that has not previously been used for commercial or industrial purposes.

**Greenhouse gas (GHG) emissions**: Gases that trap the heat of the sun in the Earth’s atmosphere, producing the greenhouse effect.

**Greenhouse gas offset**: See carbon offset.

**Grid**: A system of interconnected power lines and generators that is operated as a unified whole to supply customers at various locations. Also known as a transmission system.

**Grid emission intensity factor**: A measure of the overall electricity system’s emission intensity.

**Gross domestic product (GDP)**: One of the measures of national income and output for a given country’s economy. GDP is defined as the total market value of all final goods and services produced within the country in a given period of time (usually a calendar year). It is also considered as the sum of the value added at every stage of production (the intermediate stages) of all final goods and services produced within a country in a given period of time and is given a monetary value.
Heat rate: A measure of generating plant thermal efficiency generally expressed as units of energy input per unit of energy output.

High voltage direct current (HVDC): The transmission of electricity using direct current.

Independent system operator (ISO): A system and market operator that is independent of other market interests. In Alberta the entity that fulfills this role is the Alberta Electric System Operator.

Integrated gasification combined cycle (IGCC): A technology that turns coal into synthesis gas (syngas). Impurities are removed from the synthesis gas before it is combusted in a combined cycle generator.

Interconnection or transmission interconnection: An arrangement of electrical lines and/or transformers that provides an interconnection to the transmission system for a generator or large commercial or industrial customer.

Intertrie: A transmission facility or facilities, usually transmission lines, that interconnect two adjacent control areas.

Kilovolt-ampere (kVA): A common unit of apparent power, which is 1,000 volt-amperes. The volt-amperes carried or used by an electrical device are the mathematical products of the volts and amperes of the device.

Kilowatt (kW): One thousand watts; a measure of electric demand.

Kilowatt hour (kWh): One thousand watt hours; a measure of electric energy.

Levelized unit electricity cost (LUEC): The constant price required to cover all expenses incurred over the lifetime of a generating unit.

Load (electric): The electric power used by devices connected to an electric system.

Load factor: The ratio of average power demand (load) over a stipulated period of time to the peak or maximum for that same time interval; sometimes expressed as a per cent.

Looped system: A system of power lines in which circuits are contiguously connected between substations and then back to the same substation.

Maximum continuous rating (MCR): The maximum amount of electricity a generating unit can produce on a continuous basis.

Megavolt-ampere (MVA): One million volt-amps or 1,000 kVA.

Megavolt-ampere reactive (MVAr): A measure of the reactive component of electricity – one million volt-amps reactive.
Megawatt (MW): One million watts.

Megawatt hour (MWh): One million watt hours.

Merchant transmission line: A transmission line constructed by proponents that are not regulated utilities for the purpose of selling transmission capacity to third parties, usually generators or load customers who wish to make transactions over the merchant transmission line.

Merit order: In the electricity wholesale market, merit order refers to the list used to dispatch electric generation to meet demand. The lowest cost generation is dispatched first.

Meters or metering: Equipment that measures and registers the amount and direction of electrical quantities.

Needs Identification Document (NID): A document filed by the AESO with the Alberta Utilities Commission (AUC) to define the need to reinforce the transmission system to meet load growth and/or provide non-discriminatory access to interconnect new loads and generators to the system.

Net capability: The maximum load-carrying ability of a generator, exclusive of station use, under specified conditions for a given time interval, independent of the characteristics of the load. Capability is determined by design characteristics, physical conditions, adequacy of prime mover, energy supply, and operating limitations such as cooling and circulating water supply and temperature, headwater and tailwater elevations and electrical use.

Non-coincident peak load: The sum of two or more peak loads on individual systems, or a portion of a system, that do not occur in the same time interval.

Non-simultaneous transmission capability: A measure of transmission capability from multiple areas. Non-simultaneous means the maximum transfer capability from each area is considered one at a time and independent from each other.

North American Electric Reliability Corporation (NERC): NERC is an international independent, self-regulatory, not-for-profit organization whose mission is to ensure the reliability of the bulk power system in North America. NERC is subject to oversight by the Federal Energy Regulatory Commission (FERC) and Canadian governmental authorities and was certified by FERC as the electric reliability organization for the U.S. on July 20, 2006.

Nuclear power plant: A facility in which heat produced in a reactor by the fissioning of nuclear fuel is used to create steam in a boiler. This steam is then used to drive a turbine, which in turn drives the electric generator.

Off-peak: Periods of the day, season, year or other defined timeframe when loads are less than the maximum for the timeframe specified.

Offset: See carbon offset.
**Oilsands upgrading by-product:** High-carbon, low-energy fuel produced through the oilsands upgrading processes.

**On-peak:** Periods of the day, season, year or other defined timeframe when loads are at a maximum level for the timeframe specified.

**Operating reserve:** Generating capacity that is held in reserve for system operations and can be brought online within a short period of time to respond to a contingency. Operating reserve may be provided by generation that is already online (synchronized) and loaded to less than its maximum output and is available to serve customer demand almost immediately. Operating reserve may also be provided by interruptible load.

**Oxy-firing:** The process of combusting coal in a mixture of oxygen and re-circulated exhaust gas.

**Parallel path flow:** Electric power flows on all interconnected parallel paths in amounts inversely proportional to each path’s resistance. This also refers to the flow of electric power on one electric system’s transmission facilities resulting from scheduled electric power transfers between other electric systems.

**Peak load/demand:** The maximum power demand (load) registered by a customer or a group of customers or a system in a stated period of time. The value may be the maximum instantaneous load or, more usually, the average load over a designated interval of time such as one hour, and is normally stated in kilowatts or megawatts.

**Peaking capacity:** Generation capacity that is normally used to produce electricity during peak-load hours.

**Point-of-delivery (POD):** Point(s) for interconnection on the transmission facility owner’s (TFO) system where capacity and/or energy is made available to the end-use customer.

**Polygeneration:** An industrial system that delivers more than two products to the final user. For example, electricity, hydrogen and heating can be delivered from one polygeneration plant.

**Power pool:** An independent, central, open-access entity that functions as a spot market, matching demand with the lowest-cost supply to establish an hourly pool price.

**Pumped-storage hydroelectric plant:** A plant that usually generates electric energy during peak-load periods by using water previously pumped into an elevated storage reservoir during off-peak periods when excess generating capacity is available.

**Reactive compensation:** The ability of electrical equipment to provide reactive power.

**Reactive power:** The component of electric power that does not provide real work but is required to provide voltage.
**Reactive support**: Reactive power provided by certain types of electrical equipment, either capacitors or reactors.

**Reliability**: Electric system reliability has two components: adequacy and security. Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities.

**Reliability criteria**: A set of tests against which the operation of a power system is measured to ensure acceptable performance. The AESO’s reliability criteria are central to assessing the adequacy of the current and future Alberta transmission system.

**Reserve margin**: The percentage of installed capacity exceeding the expected peak demand during a specified period.

**Seasonal coincident peak**: A coincident peak measured within a specific period of time defined as a season. Typically summer and winter are used but fall and spring can be included as well.

**Series compensation**: A technology that is primarily used to reduce transfer reactance, most notably in bulk transmission lines. The result is a significant increase in the transmission lines’ transfer capability and system voltage stability.

**Simple cycle gas turbine**: A plant in which the prime mover is a gas turbine. A gas turbine consists typically of an axial-flow air compressor, one or more combustion chambers where liquid or gaseous fuel is burned. The hot gases are passed to the turbine where they expand, driving the turbine that in turn drives the generator.

**Single circuit**: A transmission line where one circuit is carried on a set of structures (poles or lattice towers).

**Solar power**: A process that produces electricity by converting solar radiation to electricity or to thermal energy to produce steam to drive a turbine.

**Static var compensator (SVC)**: An electrical device for providing fast-acting reactive power compensation on electricity networks.

**Substation/switching station**: A facility where equipment is used to tie together two or more electric circuits through switches (circuit breakers). The switches are selectively arranged to permit a circuit to be disconnected or to change the electric connection between the circuits.

**Supply transmission service (STS)**: The service provided to generators for interconnection access to the Alberta transmission system.

**Synthesis gas (syngas)**: A gas mixture that contains varying amounts of carbon monoxide, hydrogen, carbon dioxide and other compounds. Examples of production methods include steam reforming of natural gas or liquid hydrocarbons to produce hydrogen, the gasification of coal and some types of waste-to-energy gasification facilities.
**Tap:** A point of connection along a transmission line between substations.

**Terminal equipment:** Equipment needed to terminate a line at a substation or switching station, usually consisting of disconnect switches and breakers and voltage and current transformers used for protection and metering purposes.

**Thermal limitations:** The temperature limit of a piece of equipment or an electrical line. Electrical lines, both distribution and transmission, are typically limited by clearances to ground, buildings or other fixtures. When current flows through a wire, the wire heats up causing it to sag. The limit of clearance and the structure design determine the amount of sag allowed.

**Thermal overload:** A condition where the thermal limit of a piece of electrical equipment such as a conductor or transformer is exceeded.

**Transfer capability:** The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability can be expressed in megawatts.

**Transformer:** An electrical device for changing the voltage of alternating current.

**Transient stability:** A measure of the performance of the system in the short period, usually one to five seconds, following the application of a fault on the system.

**Transient swings:** The voltage and power oscillations that occur on a power system during the one to five second period following the application of a fault on the system.

**Transmission:** The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

**Transmission facility owner (TFO):** The owner of the system of high voltage power lines and equipment that links generating units to large customer loads and to distribution systems.

**Transmission losses:** Energy that is lost through the process of transmitting electrical energy.

**Transmission must-run (TMR):** A generator required to operate at a minimum specified output level to maintain system reliability in the event of an outage to certain transmission system elements.

**Transmission path:** One or more transmission lines that form the transmission connection between two points on the system.

**Transmission path rating:** See transfer capability.

**Transmission system (electric):** An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers or is delivered to other electric systems.
Transmission tariff: The terms and conditions under which transmission services are provided, including the rates or charges that users must pay.

Voltage: The difference of electrical potential between two points of an electrical circuit expressed in volts. It is the measurement of the potential for an electric field to cause an electric current in an electrical conductor. Depending on the amount of difference of electrical potential, it is referred to as extra low voltage, low voltage, high voltage or extra high voltage.

Voltage reduction: Any intentional reduction of system voltage by three per cent or greater for reasons of maintaining the continuity of service of the bulk electric power supply system.

Voltage stability limits: Limits established to ensure the system is operated within acceptable voltage ranges. Normal voltage limits are defined as the operating voltage range on the interconnected system that is acceptable on a sustained basis. Emergency voltage limits are defined as the operating voltage range on the interconnected system that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance.

Voltage violation: A measured or calculated condition where the voltage at a point on the transmission system is outside the acceptable limits as described in the criteria.

Watt: The unit of power equal to one joule of energy per second. It measures a rate of energy conversion. A typical household incandescent light bulb uses electrical energy at a rate of 25 to 100 watts.

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

Weighted average cost of capital (WACC): A calculation of a company’s cost of capital in which the cost of each category of capital is proportionally weighted.

Western Electricity Coordinating Council (WECC): An organization formed to coordinate and promote electric system reliability for the system that interconnects Alberta, B.C., 14 western U.S. states and part of one Mexican state.
Table of Contents

24-Month Reliability Outlook 2010 – 2012 1
What is the 24-Month Reliability Outlook 2010 – 2012? 2
How Are We Doing? 3
Table 1: Summary of Transmission Constraint Events on AIES Cutplanes from 2007 to September 30, 2010 4
Table 2: Summary of Abnormal Operation Resulting in Transmission Path or Area Limit Reductions 2007 – September 2010 in Hours Per Year 5
Table 3: Major system disturbances that occurred between January and September 2010 6
Expected Load Conditions 7
Figure 1: Yearly Actual and Forecast Summer and Winter Peak Loads 7
Supply Adequacy 8
Transmission Reliability 9
Transmission System Upgrades 10
Current Operating Conditions, Constraints and Potentially Adverse Conditions 11
Figure 2: Alberta Transmission Regions 12
Northwest Region 13
Northeast Region 14
Edmonton Region 15
Wabamun Lake/KEG and Edmonton/Fort Saskatchewan Area Bulk Transmission 16
Central Region 17
South Region 18
North-South Transmission 21
Alberta Intertie Capacity 22
Wind Integration 23
Demand Response 24
Highlights of the 24-Month Reliability Outlook 24
In Summary 25
24-Month Reliability Outlook 2010 – 2012

Competitively priced and reliable electricity is essential to ensuring Alberta’s long-term growth and our continued high standard of living and prosperity. The ability of Alberta’s electric system to meet future load growth depends on continued access to sufficient generation and a robust distribution system.

As the Independent System Operator (ISO) in Alberta, the Alberta Electric System Operator (AESO) leads the safe, reliable and economic planning and operation of Alberta’s Interconnected Electric System (AIES). We also facilitate Alberta’s fair, efficient and openly competitive wholesale electricity market, which has about 200 participants and approximately $5 billion (in 2009) in annual energy transactions.
WHAT IS THE 24-MONTH RELIABILITY OUTLOOK 2010 – 2012?

The AESO’s 24-Month Reliability Outlook provides a snapshot of the reliability of Alberta’s electricity grid from the perspective of assessing our ability to meet electricity requirements for the upcoming two-year period. It includes information on:

- load forecasts
- supply adequacy
- system constraints
- market initiatives
- transmission reinforcement underway

Electric system reliability includes two components: supply adequacy and transmission reliability. Supply adequacy means ensuring there is enough electric supply (generation) to meet consumers’ demand for power. Transmission reliability is the ability to withstand sudden disturbances or the unanticipated loss of facilities on the system. The AESO’s role is to ensure the electric system is robust and ready to keep the lights on for Albertans 24/7.

This third annual edition of the 24-Month Reliability Outlook covers the two-year period looking forward from November 2010 to November 2012 and includes information on:

- Expected load conditions, supply adequacy and transmission reliability of the AIES.
- Transmission system upgrades being put in place to improve reliability.
- Current operating conditions, constraints and potentially adverse conditions that could be avoided through coordinated maintenance plans for generation and transmission facilities.
- Key market initiatives underway.
HOW ARE WE DOING?

During the last 10 years, Alberta’s business-friendly environment has contributed to a strong economy, fast-growing population and low overall taxes. According to The Conference Board of Canada, economic growth, as measured by provincial gross domestic product (GDP), is expected to be strong in the coming decade, ranging from 2.3 to 4.5 per cent. GDP was forecast to be 3.6 per cent in 2010.

While new generation has kept pace with demand, tremendous growth over the 10 years leading up to the recession has placed pressure on the existing transmission system, which is now carrying a much higher level of power. From 2008 to 2009, average energy growth was virtually flat as strong growth in the oilsands sector was offset by the effects of the recession on other industries. However, Alberta is expected to experience strong economic growth over the next five years and long term as investment in and development of the oilsands spurs economic growth and job creation. In effect, the recession provided time for transmission development to catch up with growth in demand for electricity.

Despite the recent economic downturn, parts of the electric system continue to experience constraints that limit the ability to transmit power between various locations in Alberta. In some parts of the province, constrained transmission lines can strand electricity supply, making it unavailable to the market. In other areas constraints occur when there is not enough transmission capacity to serve local load. For example:

- Transmission must-run (TMR) services are required in the Rainbow Lake, northwest Alberta and Calgary areas to maintain system reliability.
- Wind power generation constraints continue in the Southwest region—even with the new 240 kilovolt (kV) developments in place—due to the need for additional reinforcement of the transmission system in that area.
- Some regions (see Table 1) experience generation or load constraints when transmission facilities are taken out of service for planned maintenance or by forced outages.

Constraints on the electric system mean the impact of planned and forced outages on transmission elements are becoming more obvious as indicated in Table 1 and 2. The AESO is meeting this challenge through:

- Planning transmission system development.
- Ongoing emphasis on coordination of planned outages.
- Developing and implementing reliability standards and operating tools and procedures.
- Augmenting training and introducing new programs to help system operators manage and maintain system reliability.
- Developing operating limits and tools in advance of each project stage of transmission development.
With the addition of new generation and continued demand growth, we expect the level of congestion on the AIES to intensify until more transmission is built. For the AESO, the priority remains timely approval and implementation of proposed transmission upgrades. As of October 31, 2010, total installed generation capacity on the Alberta system is 12,915 megawatts (MW) and peak demand of 10,236 MW occurred on December 14, 2009.

Table 1 summarizes constraint events considered to form part of the abnormal operating conditions contemplated in Transmission Regulation AR 86/2007. Constraints can occur due to outages for planned maintenance, outages planned for adding a new facility to the grid or forced outages of transmission elements. Table 2 identifies the number of hours where abnormal operating conditions of different cutplanes resulted in limited transfer capability. Table 3 lists major system disturbances that occurred during January to September 2010.

Table 1: Summary of Transmission Constraint Events on AIES Cutplanes from 2007 to September 30, 2010

<table>
<thead>
<tr>
<th>Cutplane or area</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>Jan. 1 - Sept. 30, 2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fort McMurray</td>
<td>3</td>
<td>2</td>
<td>8</td>
<td>27</td>
</tr>
<tr>
<td>Keephills-Ellerslie-Genesee (KEG)</td>
<td>1</td>
<td>1</td>
<td>2</td>
<td>14</td>
</tr>
<tr>
<td>South of KEG (SOK)</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Southwest Wind</td>
<td>24</td>
<td>89</td>
<td>92</td>
<td>83</td>
</tr>
<tr>
<td>Medicine Hat</td>
<td>0</td>
<td>28</td>
<td>23</td>
<td>4</td>
</tr>
<tr>
<td>Airdrie Area</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>6</td>
</tr>
<tr>
<td>South of Anderson</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>Edmonton Area</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>3</td>
</tr>
</tbody>
</table>
### Table 2: Summary of Abnormal Operation Resulting in Transmission Path or Area Limit Reductions 2007 – September 2010 in Hours Per Year

<table>
<thead>
<tr>
<th>Cutplane or area</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010 Jan – Sep</th>
<th>Reason for 2010 Abnormal Operation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fort McMurray</td>
<td>438</td>
<td>438</td>
<td>769</td>
<td>691</td>
<td>Planned and forced outages</td>
</tr>
<tr>
<td>Keephills-Ellerslie-Genesee (KEG)</td>
<td>0</td>
<td>0</td>
<td>180</td>
<td>1,023</td>
<td>Mostly due to construction outages required for debottlenecking project</td>
</tr>
<tr>
<td>South of KEG (SOK)</td>
<td>526</td>
<td>613</td>
<td>591</td>
<td>1,094</td>
<td>Planned and forced outages</td>
</tr>
<tr>
<td>Southwest wind</td>
<td>100</td>
<td>800</td>
<td>968</td>
<td>983</td>
<td>Mostly during N-0 operation</td>
</tr>
<tr>
<td>Medicine Hat</td>
<td>0</td>
<td>500</td>
<td>443</td>
<td>435</td>
<td>Planned and forced outages</td>
</tr>
<tr>
<td>Airdrie area</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>118</td>
<td>Planned and forced outages</td>
</tr>
<tr>
<td>South of Anderson</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1,096</td>
<td>Due to spring storm damage</td>
</tr>
<tr>
<td>Edmonton area</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>19</td>
<td>Mostly due to construction outages required for debottlenecking project</td>
</tr>
</tbody>
</table>

24-Month Reliability Outlook (2010 – 2012)
### Table 3: Major system disturbances that occurred between January and September 2010

<table>
<thead>
<tr>
<th>Event</th>
<th>Date</th>
<th>Summary</th>
</tr>
</thead>
</table>
| **Northwest area** blackout   | March 1, 2010| **Cause:** Accidental contact of construction crane with 144 kV line, wrong setting on 240/144 kV transformer protection, severe overload and tree contact  
**Impact:** Loss of 338 MW of load  
**Action:** 1. ATCO Electric: a. Trimmed trees under a 138 kV line and plan to review vegetation management program.  
b. Review contractor and crew training.  
c. Review transformer differential protection relay setting procedures. |
| Southeast storm                | April 8, 2010| **Cause:** Severe winter weather conditions with heavy winds  
**Impact:** Damage to several transmission lines in the south AIES affecting AltaLink, ENMAX, ATCO Electric, EPCOR and City of Medicine Hat systems and area customers  
**Action:** TFOs and DFOs used best efforts to restore the system and load. |
| Southeast storm                | April 14, 2010| **Cause:** Snowstorm with high winds in southeast and northeast Alberta  
**Impact:** Numerous outages to TFO and DFO systems and damage to double circuit three terminal line towers resulting in generation curtailments to Sheerness and Battle River plant generators for almost 1.5 months; affected 240 kV lines restored to service June 1, 2010.  
**Action:** TFOs and DFOs used best efforts to restore system and load and repaired damaged transmission and distribution lines. |
| Southeast storm                | April 29, 2010| **Cause:** Severe weather conditions with high winds, snow and rain  
**Impact:** Loss of customer load in the ENMAX, Fortis and the City of Lethbridge service areas |
| Under frequency (UFLS) event  | June 1, 2010 | **Cause:** Lightning and equipment failure at Sheerness plant  
**Impact:** 663 MW of load lost due to UFLS trips and as a result of voltage and frequency excursions  
**Action:** 1. Sheerness plant replaced failed relay.  
2. UFLS providers revised UFLS program and fixed relay issues. |
| 947L (Ellerslie 89s – Clover Bar 967s) | June 30, 2010| **Cause:** Line was energized with ground chains unintentionally left on  
**Impact:** Voltage depression and subsequent 320 MW of load lost in Edmonton and Fort Saskatchewan areas  
**Action:** AltaLink reviewed the incident to understand root causes, identifying and implementing improvements to procedures and/or staff training to avoid similar occurrences in the future. |

1 Disturbance affected the following planning areas in the AESO’s Northwest region: Rainbow Lake, High Level, Peace River and High Prairie.  
2 TFO = Transmission Facility Owner  
3 DFO = Distribution Facility Owner
EXPECTED LOAD CONDITIONS

The Province of Alberta is expected to show steady economic growth over the long term. According to the AESO's Future Demand and Energy Outlook (2009–2029), average annual demand is forecast to grow by 3.5 per cent for the next five years.

In 2009/2010, the Alberta Internal Load (AIL)\(^4\) winter peak demand reached a record high of 10,236 MW and the 2010 summer peak was 9,343 MW. An all-time summer peak of 9,541 MW occurred in 2008. Long-term load forecast winter peaks are 10,170 MW for 2010/2011 and 10,577 MW for 2011/2012. The forecast peak demand for summer 2011 is 9,912 MW and 10,408 MW for 2012. For winter 2012/2013, the forecast peak demand is 11,076 MW while summer 2013 is anticipated to reach a peak of 10,941 MW.

On a year-over-year basis, Alberta’s total energy consumption for the first 11 months of 2010 was 2.5 per cent higher than for the same period in 2009. The season-to-date winter 2010/2011 peak is 10,191 MW, just 0.2 per cent higher than forecast. There is no indication that peak load for the next 24 months will vary greatly from long-term load forecast expectations.

Figure 1 shows AIL yearly actual and forecast peak loads from 2003 to 2012. Actual load for the period November 2010 to November 2012 will depend on factors such as:

- weather conditions
- actions of price responsive load (approximately 175 to 300 MW)
- new oilsands projects and associated industry coming on stream

Figure 1: Yearly Actual and Forecast Summer and Winter Peak Loads

\(^4\) Alberta Internal Load (AIL) is defined as the province’s total electricity consumption, including losses through transmission and distribution, as well as load served by behind-the-fence generation.
SUPPLY ADEQUACY

Supply adequacy is the ability of installed generation to supply the total electrical demand and energy requirements of customers and operating reserves at all times. In the near term, supply adequacy also considers scheduled and reasonably expected unscheduled transmission and generation outages on the electricity system.

In Alberta, investor-driven market decisions will determine the amount of generation added to the electrical system in the next two years. Over the past few years, the province has seen significant investment in new generation projects with 600 MW of new supply added to the system in 2009 and approximately 500 MW in 2008. This investment is expected to continue and produce reserve margins similar to historic levels.

Currently there is approximately 420 MW of generation capacity energized and in the commissioning phase and approximately 825 MW of new generation under construction and expected to come online in the next two years. In addition, 408 MW of generation projects have received Alberta Utilities Commission (AUC) power plant approval and 1,140 MW of generation projects have been announced corporately or have applied for regulatory approval with the intention of starting construction within the next two years. This excludes wind projects that have not applied to the AUC for power plant approval.

The 450 MW Keephills 3 power plant makes up a large part of generation capacity under construction. The plant will add baseload capacity to Alberta’s generation mix when it begins commercial operation in 2011. As generation projects under construction move into commercial operation and projects with regulatory approval proceed, supply levels will increase to meet growing demand.

In March 2010, the last of TransAlta’s Wabamun coal-fired generation units, 279 MW Wabamun 4, was decommissioned after 54 years of service. The new generation described above will more than offset the Wabamun retirement.

Overall generation capacity, as indicated in the daily supply cushion from November 1, 2010 to October 31, 2012, is adequate to meet daily peak demand over the next two years. However, it will be necessary to continue to closely coordinate generator and transmission outages to ensure congestion does not strand a significant amount of generation.

As per Alberta’s Transmission Regulation 86/2007, the AESO has developed rules regarding generator outage cancellation and filed them with the AUC. The rules, which were effective October 28, 2010, define the steps the AESO will take and issues that will be considered when cancelling a planned outage in order to maintain supply adequacy and reliable operation.

The AESO performs a number of assessments to monitor the ability of supply to serve demand and satisfy contingency requirements in the short to medium term (one day to 24 months) and the long term (up to five years). These assessments indicate supply reserve margins will be adequate during the next two years but close coordination of generator and transmission outages is required to ensure adequate supply and to avoid constraint events during the real time operation. Further information can be found at www.aeso.ca
TRANSMISSION RELIABILITY

We describe transmission reliability (sometimes referred to as operating reliability or system security) as the ability of the electric system to withstand sudden disturbances or the unanticipated failure of system elements.

As it relates to reliability, risk is the likelihood that an event (i.e., an outage or change in operating conditions) will reduce the reliability of the power system to the point that consequences are unacceptable (e.g., equipment damage or cascading outages). Since unforeseen events like sudden disturbances or the unanticipated failure of system elements cannot be prevented, the AESO plans and operates the electric system so that when these events occur, the effects are manageable and consequences are acceptable as defined in the Alberta Reliability Standards and AESO Reliability Criteria. It is critical to effectively manage risk to ensure the power system is operated reliably.

To do this, we regularly perform operations planning studies to assess the operability and reliability of the transmission system under a broad range of conditions. System operators use the results to establish operating limits and procedures that protect generation and transmission equipment from damage that could jeopardize reliability for weeks or even months. Results are also used to support integration of new generation and transmission facilities and to facilitate the coordination of outages.

Reliable system operation depends on a continuously connected and managed power system with synchronized generation, transmission and load. System operators monitor the overall reliability of the power system on a moment-by-moment basis by keeping flows within limits while matching supply with demand.

Another safeguard of Alberta’s electric system reliability is the AESO’s adherence to criteria developed by the North American Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC). The NERC/WECC reliability standards and criteria are central to assessing the adequacy of the future transmission system. With an adequately planned system and prudent operating criteria, we can operate the system reliably while facilitating an open and competitive market.

The AESO carries out studies that apply the NERC/WECC reliability criteria on a regular basis. In addition, we support implementation of consistent standards to maintain and improve the reliability of the North American grid by adopting a made-in-Alberta set of standards that guide the operation of the province’s electric system.

The NERC has approved over 120 reliability standards and 34 of these have been adopted for Alberta and published to the AESO website following extensive stakeholder consultation. Several standards have been assessed as not applicable to Alberta. The remaining reliability standards will continue to be assessed in 2011 and the AESO will continue to monitor changes to NERC and WECC standards.
TRANSMISSION SYSTEM UPGRADES

One of the AESO’s priorities remains timely approval and implementation of proposed transmission upgrades to meet future electricity demand, interconnect generation, satisfy reliability requirements and upgrade the power system in the best interest of Albertans.

These proposed upgrades include improving the transfer capacity of interties that connect Alberta’s transmission system to the neighbouring jurisdictions of Saskatchewan and B.C., and connecting a new intertie to Montana. The province’s electric system reliability is enhanced by these connections, which allow us to import power to meet peak demand in the summer and winter and help prevent power outages by providing access to additional back-up power in case of sudden equipment failure.

To keep pace with Alberta’s continued growth in load and generation and enhance reliability, several transmission upgrades were completed in 2010. These include:

- Southeast Alberta Transmission Development Project fully energized, including two new 27 MVAr capacitor banks at the McNell converter station and restoration of 150 MW capacity on the Alberta–Saskatchewan intertie in both directions independent of Amoco area load.
- 240/138 kV transformer capacity increased at north Lethbridge 370s.
- New 240 kV double circuit transmission lines energized in the southwest area.
- 947L energized from 89s Ellerslie to 987s Clover Bar.
- 1202L energized at 500 kV from Keephills plant 320P to Ellerslie 89s.
- New 144 kV double circuit transmission lines energized between Wesley Creek 834s to Meikle 905s and further to Hotchkiss 788s.
- Two new static VAR compensators (SVCs) (100 MVar at 813s Little Smoky and 30 MVar at 786s High Level) installed in the Northwest region.
- Two new oilsands interconnections in the Fort McMurray area completed.
- Several 138/25 kV and 144/25 kV transformer additions completed to serve increased distribution loads and load customer interconnections.
CURRENT OPERATING CONDITIONS, CONSTRAINTS AND POTENTIALLY ADVERSE CONDITIONS

This section looks at the operating conditions, limits and potentially adverse conditions that might occur throughout the 2010/2011 winter operating season and over the November 2010 to November 2012 timeframe of the 24-Month Reliability Outlook.

Peak demand and thermal ratings\(^5\) of transmission equipment are higher in the winter. Because of this, planned maintenance on transmission and generating assets generally happens in the summer. This often results in more stress on the transmission system during the summer electricity season.

When overall Alberta supply reserve margin is low, all generators are expected to be in merit\(^6\). High market prices for energy are likely to attract imports, which bring power into the south central part of the transmission system. Higher winter thermal ratings and all supply being in merit during peak periods should create an overall sufficient level of transmission reliability for winter 2010/2011.

Another factor contributing to increased transmission reliability is reduced flow on the South of Keephills-Ellerslie-Genesee (SOK) 240 kV cutplane\(^7\) due to south gas generation being in merit during high load periods in southern Alberta.

As system load continues to grow and generation develops in specific areas, the effects of contingencies (sudden failures or outages on the system) become increasingly pronounced. Close coordination of generator and transmission outages is required to ensure adequate supply and avoid constraint events during real-time operation.

The AESO is meeting this challenge through transmission development and continued emphasis on coordination of planned outages and developing enhanced operating tools, real-time studies, procedures and training for our system controllers, and an ongoing emphasis on comprehensive analysis and follow up should disturbances occur.

There are immediate and significant operating challenges in the Northwest, Northeast, Edmonton, Central and South regions of the province that require constraint management and special operating procedures, use of TMR generation, remedial action schemes and coordination of transmission and generation outages. These are described on the following pages.

---

\(^5\) Thermal ratings are the maximum amount of electrical current transmission facilities can conduct over a period of time without overheating and causing permanent damage or violating equipment safety margins.

\(^6\) Generation assets dispatched by the system controller and eligible to set the pool price are described as being in merit.

\(^7\) A cutplane is an imaginary line that cuts across transmission lines connecting two or more areas. The loading on these lines is summed together to measure the power flow across the cutplane.
Figure 2: Alberta Transmission Regions

Existing transmission lines
Voltage
- 69/72 kV
- 138 kV
- 240 kV
- 500 kV
NORTHWEST REGION

The Northwest region of Alberta is a geographically large area northwest of the City of Edmonton. It is bordered by Fort McMurray and Athabasca to the east, Hinton and Wabamun to the south, B.C. to the west, and the Northwest Territories to the north. While this region represents approximately one-third of the area of the province, it represents only one-tenth of total demand on the electric system.

The Northwest region includes the Rainbow Lake, High Level, Peace River, Grande Prairie, High Prairie, Grande Cache, Valleyview, Fox Creek and Swan Hills planning areas but not the Wabamun Lake area. It is connected to the Wabamun Lake area primarily through three 240 kV transmission lines and is connected to the Fort McMurray area through one new 240 kV transmission line. The Northwest region contains approximately 1,100 MW or 11 per cent of the provincial peak load but only 798 MW of generating capacity. Due to this imbalance, the region typically imports between 530 and 755 MW of power from the Wabamun Lake and Fort McMurray areas. The AESO contracts TMR services so a minimum amount of generation stays online to ensure power transfers into the region are kept within operating limits.

Within the Northwest region, the Grande Prairie area also requires TMR to meet reliability criteria as the area does not have sufficient local transmission capacity. The amount of TMR services required depends on whether or not the power transfer to this area exceeds specific limits. In addition, the Rainbow Lake area lacks sufficient transmission capacity to support area load and TMR services are required 100 per cent of the time. Future northwest system reinforcements in the Rainbow Lake area are expected to be in service by mid-2012, reducing the need for TMR. Future generator interconnections in this area may also reduce the need for TMR.

Transmission resources added or expected to be commissioned in the Northwest region between 2010 and 2012 include:

- Installation of two new SVCs (±100 MVar at 813s Little Smoky and ±30 MVar at 786s High Level).
- Energization of new 144 kV double circuit transmission lines between Wesley Creek 834s to Meikle 905s and further to Hotchkiss 788s.
- Energization of new 144 kV line 7L133 between Sulphur Point 828s and High Level 786s.
- Installation of one new SVC and one new sync condenser at the new Arcenciel 930s substation.

These additions will improve area transfer capability and voltage control and reduce the dependence of area load on TMR services.

---

8 Limits are based on transmission system conditions and baseloaded generation online in real time.
NORTHEAST REGION

The Northeast region of Alberta is bounded on the north by the Northwest Territories, on the east by the Saskatchewan border, on the west by the Fifth Meridian, and on the south by the Edmonton, Wetaskiwin, Vegreville and Lloydminster planning areas. The region’s boundary was revised in 2010 to include the Fort McMurray, Athabasca/Lac La Biche, Cold Lake and Fort Saskatchewan planning areas.

The Northeast region is forecast to experience the greatest load growth of any region over the next 10 years. This is due in large part to the oilsands, upgraders, forestry industries and related secondary service industries in the municipalities within the region.

Load in the Northeast region is predominantly industrial and makes up approximately 2,197 MW or 22.4 per cent of provincial peak load. The majority of the electrical load and generation is located in oilsands developments north of the City of Fort McMurray and in Cold Lake and Fort Saskatchewan. Generation in the region is mainly gas-fired cogeneration that accounts for about 23.2 per cent or 3,001 MW of Alberta’s 12,915 MW of total installed generation capacity.

The Fort McMurray area is connected to the transmission system by three 240 kV transmission lines and, under typical operating conditions, exports approximately 301 MW. The area continues to experience high load growth related to oilsands development; however, the economic downturn of 2008/2009 has delayed several new oilsands-related loads by at least one year. Major developers have reviewed their plans and made announcements to activate those projects. It is expected that load and on-site generation development in the area will effectively balance out in the short term. This should result in relatively minor changes to existing transfer levels between the Fort McMurray area and the rest of the AIES.

The current transmission system does not have the capacity to supply the entire load of the Fort McMurray area without support from local generation. However, a significant amount of the area generation is baseload industrial cogeneration and, under normal operating conditions, is adequate to support reliable operation. In 2012, under normal transfer limits, the Fort McMurray cutplane is expected to experience a small number of hours (31 hours for inflow, four hours for outflow) where flows may exceed current transfer limits. The AESO plans to install capacitor banks of 260 MVARs to improve area inflow and outflow transfer capabilities and manage voltage to help maintain reliability in the area.

The Fort McMurray area experienced real-time constraints twice in 2008, eight times in 2009 and 27 times between January and September 2010. Enhancing transfer capabilities into the area will be achieved by adding more voltage support devices during the next two years. Longer-term plans include constructing 500 kV lines into this area.
The Cold Lake area has surplus generation and thermal constraints on the transmission system that are managed through special protection schemes. A Needs Identification Document (NID) has been filed with the AUC for the Central East region (which includes the Cold Lake area) to address long-term transmission needs. The NID proposes construction of two 240 kV lines and a substation, both to be initially operated at 144 kV. In addition, a number of existing 144 kV lines will be upgraded to a higher rating to alleviate existing bottlenecks. The majority of the proposed reinforcements are targeted to be in service by the fourth quarter of 2012. This proposed plan will facilitate both projected load growth of 6.4 per cent and the connection of about 250 MW of cogeneration facilities in the Cold Lake area.

The Heartland Transmission Project is required to support local demand in the Heartland area, accommodate demand in northeast Alberta, including Fort McMurray, and provide effective system integration for the Edmonton to Calgary Transmission Reinforcement Project.

EDMONTON REGION

The Edmonton region encompasses the City of Edmonton and includes the Wetaskiwin, Wabamun and Edmonton planning areas. This region is the hub of Alberta’s electric system and comprises 2,013 MW or 20.5 per cent of provincial peak load and has 4,457 MW or 34.5 per cent of Alberta’s generation capacity. Most of the generation is baseload coal-fired power located around Wabamun Lake and flows east and south with smaller amounts flowing north and west.

The transmission system in the Edmonton region has the capacity to serve firm load in the region when all transmission elements are in service and baseload generation is online in the Fort Saskatchewan area. The 138 kV system south and west of the City of Edmonton is thermally constrained due to increased load in the area. During high load conditions, Category B\(^9\) events may overload the 138 kV lines, creating a risk of the system not meeting reliability criteria. When one transmission element is out of service due to planned or forced outages, there are several local area constraints on the 138 kV system. The 138 kV system contingencies only affect local areas within the region and risks are not expected to spread to the 240 kV backbone of the system. The AESO is planning to file a NID for these 138 kV area system reinforcements by the second quarter of 2011 with development in place by the end of 2012. In the mean time, the AESO is developing a procedure to mitigate overload in the area during real-time operation.

\(^9\) Category B events result in the loss of any single specified system element under specified fault conditions and normal clearing.
**WABAMUN LAKE/KEG AND EDMONTON/FORT SASKATCHEWAN AREA BULK TRANSMISSION**

The Wabamun Lake area is experiencing major transmission upgrades as part of the interconnection of the Keephills 3 generator and related reconfiguration of Edmonton area 240 kV lines (also referred to as debottlenecking). Construction of these transmission system upgrades began in the summer of 2010. The proposed transmission capacity upgrades include converting the existing line 1202L 240 kV to 500 kV, adding a new 240 kV line between the Keephills generator and the Edmonton area, upgrading the capacity of several 240 kV lines and installing phase-shifting transformers at Keephills 320P and in the Fort McMurray area. These major transmission developments in the Wabamun Lake area will remove congestion and facilitate interconnection of the new Keephills 3 generator.

After the debottlenecking project is complete, three 240 kV lines will be in place to transport electricity from the Sundance generating plants to the Edmonton area. Three 500 kV lines and one new 240 kV high capacity line will connect the Keephills and Genesee generating plants to the Edmonton area. A phase-shifting transformer will be installed at 240 kV at the Keephills plant in the path of the 240/500 kV existing transformer. The phase-shifting transformer will help mitigate Category B and C10 overloads and, in combination with the phase-shifting transformer in the Fort McMurray area, will facilitate increased transfer capacity to serve Northeast region load.

Operations studies are currently underway for the final stage of the Wabamun Lake area transmission upgrade to determine the operating limits of the Keephills-Genesee, South of Keephills-Ellerslie-Genessee (SOK) and Northeast11 cutplanes and ensure the area operates as required by reliability criteria and standards. For reliable system operation, Operating Policy and Procedure 517 and operator tools will be revised to ensure the total Keephills-Ellerslie-Genessee (KEG) net-to-grid generation online will not exceed the dynamic stability limit of the different cutplanes. A procedure will also be established to operate the phase-shifting transformers at Keephills and in the Fort McMurray area.

The reactive support limitations on legislated Power Purchase Arrangement units in the KEG loop can create operational concerns during peak summer load conditions. The AESO continues to work with generator owners/operators to address this issue.

This area was constrained several times in 2010 during the construction phase of the Keephills 3 interconnection and related transmission upgrades project. Congestion may continue to occur until the second quarter of 2012 as a result of transmission line outages required to complete the planned transmission upgrades in the Wabamun Lake area described above.

---

10 Category C events result in the loss of two specified system elements under specified fault conditions and include both normal and delayed fault clearing events.

11 The Northeast cutplane consists of four 240 kV circuits: 920L (Clover Bar 987s to Lamoureux 71s), 921L (Castle Downs 557s to Lamoureux 71s), 9L56 (Mitsue 732s to Brintnell 876s) and 9L15 (Brintnell 876s to Wesley Creek 834s) that provide transfer paths for energy to and from the Northeast region.
CENTRAL REGION

The Central region is located between Edmonton and Calgary and includes the Lloydminster, Hinton/Edson, Drayton Valley, Wainwright, Abraham Lake, Red Deer, Alliance/Battle River, Provost, Caroline, Didsbury, Hanna and Vegreville areas. This region contains approximately 1,573 MW or 16 per cent of the provincial peak load and generation capacity totals 13.5 per cent or 1,740 MW of Alberta’s total installed generation capacity. Area generation is a mix of hydro, coal-fired and industrial gas-fired cogeneration.

The transmission system in the Central region has the capacity to serve firm loads in the region when all elements are in service during normal operation. When the system is operating with one element out of service (N-1), a number of next contingency scenarios can result in voltage violations and/or overloads in different parts of the region. Reliable transmission system operation is maintained through established procedures, operating limits and AESO–transmission facility owner coordination of maintenance through weekly system coordination plans.

Additional new pipeline load is expected during 2010 and 2011 to support the transfer of bitumen and oil products from oilsands projects in the East Central region (Cold Lake area to Amoco Empress). New capacitor banks were installed in 2009, remedial action schemes (RAS) and under voltage load shed schemes (UVLS) will be installed in 2010 to address voltage constraints that are expected after Keystone pipeline phase 2 loads come online. With the AUC’s approval of the Hanna NID phase 1, which includes 240 and 138 kV transmission reinforcement, SVCs and capacitor banks, new 240/144 kV transformations and 72/144 kV system reconfigurations are scheduled to be completed in 2012. These upgrades will mitigate thermal and voltage stability constraints that currently exist on the 72 kV and 144 kV systems in the Hanna area.

The AESO is also planning to file a NID for transmission development in the Caroline, Red Deer and Didsbury areas in 2011. The transmission reinforcement described in the NID will mitigate existing system constraints caused by load growth, wind farm connections and operational issues in these areas, including thermal overloads on the 138 kV system parallel to south of the KEG 240 kV path.
### SOUTH REGION

The South region of Alberta has the Canada-U.S. border to the south and is bordered on the north by the Abraham Lake, Caroline, Didsbury and Hanna areas and on the west and east by B.C. and Saskatchewan respectively. The region makes up approximately 2,925 MW or 29.8 per cent of the province’s peak load (mainly residential) and produces 22.7 per cent or 2,919 MW of Alberta’s total installed generation capacity. The generation is a mix of hydroelectricity, gas-fired, coal-fired and approximately 695 MW of wind facilities.

Transmission capacity in the southeast has been enhanced significantly since the Amoco Empress area transmission addition was completed in 2009 and 2010. This transmission development restored the Alberta–Saskatchewan intertie limits to the original design level of 150 MW in both directions under normal conditions. The upgrade has also improved system performance on 240 kV line contingencies. Constraints may occur due to limitations within the Saskatchewan system or during planned or forced outages to transmission facilities within the Alberta system.

Transmission constraints on the 138 kV system in the southeast will continue until phase 1 of the Southern Alberta Transmission Reinforcement (SATR) project is completed. This will move significant load from the existing system to the new 240 kV system at Bowman substation.

After the southwest 240 kV development is completed during the fourth quarter of 2010, wind generation curtailments due to transmission constraints will be reduced. However, some curtailments under normal system operation will continue until phase 1 of the SATR Project is completed. Once this is done, transmission capacity to support existing and new wind generation in the southwest and southeast will be enhanced.

The overload remedial action schemes (RAS) on the southwest system will continue and new RAS may be required as new wind generation comes online before the completion of SATR Phases I and 2. These RAS have been installed to ensure the area transmission system meets the performance requirements of Category A, B and C contingencies.

A dynamic thermal line rating system (DTLR) commissioned on the 170L line between Pincher Creek 396s and Peigan 59s substations helped reduce transmission constraints in the southwest area. As part of reconductoring of 616L between 616AL to Goose Lake 103s, the 103s end does not have DTLR because new equipment was required for a new line conductor. The 616L section between 616AL and Peigan 59s will continue to be monitored by the DTLR application and the 616L-59s RAS triggers will continue to be based on DTLR ratings when available. However, after the southwest 240 kV transmission developments and reconfigurations are completed, the DTLR based line ratings will be of benefit only when the 240/138 kV transformers experience forced outages during high wind generation in the area.
Thermal constraints on the 240/138 kV transformers at West Brooks and North Lethbridge and on the 138 kV system serving the City of Lethbridge were removed in 2010 by upgrading transformation capacity at West Brooks and adding a third transformer at North Lethbridge. One new 138 kV line has been added to address constraints to City of Lethbridge load.

Operations studies conducted in 2009 on the Sheerness area determined the Sheerness generators can be unstable in post N-1, N-1-1 and N-2 conditions when the flow from Anderson A801s to West Brooks/Ware Junction on the 240 kV lines exceeds specific limits based on the number of lines in service. The AESO is currently consulting with affected market participants and reviewing options to address the constraint. The Hanna area development (the first phase of the Hanna area NID approved by the AUC is expected to be in service in 2012) may improve the Anderson area performance. Operating studies are underway to evaluate the impact.

The current 240 kV bulk system between Calgary and the south of the province is approaching capacity and will require substantial reinforcement to accommodate south-to-north transfers related to new wind generation. The AESO is currently performing system analysis to identify transmission developments south of Calgary that will improve transfer capacity between Calgary and southern Alberta, allow interconnection of ENMAX’s Shepard generation plant to the AIES and remove current constraints on the ENMAX service area transmission system.

The AESO and AltaLink are developing project schedules and specifications for SATR Phases 1 and 2, with project components expected to be in service beginning February 2011 with completion by June 2015.

The transmission system in Calgary is reaching its limit and it is becoming increasingly difficult to arrange maintenance on many transmission facilities due to pressure placed on the lines by load growth. When specific transmission equipment is removed from service for maintenance, the next single contingency can result in uncontrolled loss of load in the area.
The AESO filed a NID with the AUC in July 2009 to replace the existing four transmission cables and terminal equipment serving the Calgary central business district with four new cross-linked polyethylene underground power cables with summer and winter capacity of approximately 300 MVA each. The proposed service date is the third quarter of 2012 and part of the project will be in place by the second quarter of 2011. In addition, new point of delivery substations and 138/25 kV transformers were added in 2009 to serve increased load on the ENMAX transmission system.

The 138 kV system in the Airdrie area is experiencing thermal and voltage constraints. Two new 27 MVAR capacitor banks were added to the area in the third quarter of 2010 to mitigate voltage constraints. The new ENMAX generator at Crossfield requires application of a RAS to address thermal constraints. The NID for the Airdrie area reinforcement will be filed in the fourth quarter of 2010 to remove thermal constraints and serve increased load in the area.
NORTH–SOUTH TRANSMISSION

The Edmonton to Calgary bulk transmission system is comprised of six 240 kV lines between the Wabamun Lake/Edmonton area and Calgary. These six circuits are collectively referred to as the South of Keephills-Ellerslie-Genesee (SOK) cutplane. These lines transfer baseload coal generation and Brazeau hydro generation to the southern part of the province to meet major load requirements of the Calgary region. In addition, these lines provide access to the Alberta–B.C. intertie.

The power flow across the SOK cutplane and minimum voltage levels at several key buses on the north-south path are used to define the transfer capability of the north-to-south flow. Under normal transfer limits, with all elements in service, the SOK 240 kV system has the capacity to accommodate forecast flows in 2012. However, during planned and forced transmission and generator outages, south load may need to rely on constraint procedures, including the use of TMR services, to ensure south supply is dispatched.

Without the completion of transmission development between Edmonton and Calgary, the projected flows on the SOK 240 kV system will pose a concern, especially during transmission and generation outages, to the operation and reliability of the AIES by the end of 2012. The AESO will continue to monitor the situation and develop mitigation plans to address these concerns until such time as approved transmission developments are in service.
ALBERTA INTERTIE CAPACITY

As new interties are being contemplated from multiple jurisdictions, the AESO is currently consulting with stakeholders to review the intertie framework to ensure it supports fair, efficient, and openly competitive transactions while advancing government policy. As the Montana–Alberta intertie is under construction, the immediate focus is the requirement to reallocate limited capacity among multiple interties.

One 500 kV circuit and two 138 kV circuits between Alberta and B.C. comprise three circuits the Western Electricity Coordinating Council (WECC) defines as Path 1. The current path rating of the B.C. intertie is 1,000 MW in an export\(^{12}\) mode and 1,200 MW in an import\(^{13}\) mode. However, the actual operating limit is much lower due to the need to maintain acceptable levels of frequency in Alberta in the event of intertie separation while importing, and voltage concerns in the Calgary area in the event of 240 kV line trips in the Calgary area while exporting. These restrictions mean the maximum total transfer capability (TTC) import and export of the B.C. intertie is reduced to 780 and 800\(^{14}\) MW respectively. Transmission upgrades in Alberta and B.C. as well as an Alberta generator-tripping scheme are required to increase export capacity to B.C. from the current maximum TTC of 800 MW.

To protect against a single generator contingency of up to 450 MW from cascading and tripping the intertie, the maximum TTC for imports on the Alberta–B.C. intertie is 780 MW. This import capability is made available through an interruptible load remedial action scheme (ILRAS) and load shed services (LSS). The AESO is currently reviewing the design and use of these programs with stakeholders.

The McNeill back-to-back alternating current (AC) to direct current (DC) converter station that connects Alberta and Saskatchewan is referred to as WECC Path 2. Since the completion of transmission system developments in the Amoco Empress area in 2009/2010, the maximum import and export TTC of 150 MW is available. However, constraints on the Saskatchewan system may lower the TTC during real-time operation.

The Montana Alberta Tie Line (MATL), a 230 kV intertie between Montana and Alberta, is expected to be in service during 2011. This intertie will provide an alternate source of energy exchange between Alberta and the northwest U.S.; however, the MATL is not expected to increase the net import and export limits between Alberta and the remaining WECC system.

\(^{12}\) Alberta to B.C.
\(^{13}\) B.C. to Alberta
\(^{14}\) As per AESO OPP 304.
WIND INTEGRATION

Wind power facilities in the province have relatively high capacity factors, with some reaching as high as 35 per cent on an annual basis, making Alberta an attractive place for wind development. Wind power in Alberta has seen substantial growth in the last few years. As of November 2010, 695 MW of generating capacity from 13 wind farms, 5.4 per cent of total installed generation capacity, was connected to the transmission system. Wind power provided 2.6 per cent of the total power generated in Alberta (excluding imports) between January and September 2010. There continues to be strong interest in building wind generation. There are over 7,000 MW of wind generation projects in the connection queue, with a large portion (2,600 MW) of that total amount slated to be connected to the grid over the next 24 months.

The AESO is currently pursuing several initiatives to further refine and define rules, standards, information technologies and tools needed to integrate as much wind power into the Alberta system as feasible without compromising system reliability or the fair, efficient and openly competitive operation of the market. In September 2010, the AESO published the Short Term Wind Integration Recommendation Paper describing the tools and practices needed to integrate 1,100 MW of wind to the system by the end of 2011. The AESO will be releasing a discussion paper outlining possible products and market rules that will take longer to implement but are intended to support the amount of wind capacity expected in Alberta for 2012 and beyond. Wind power forecasting is also being integrated into a variety of market systems and the AESO is working with wind facility owners to improve and efficiently utilize the wind power forecast.

Alberta continues to be a leader in wind integration. The province provides an attractive environment for future wind power development because of our market structure, significant wind regimes and the AESO’s forward-looking initiatives developed in consultation with industry stakeholders, as well sharing best practices in wind integration with ISOs across North America. More information about the AESO’s wind integration initiatives can be found at www.aeso.ca

15 The net capacity factor of a power plant is the ratio of the actual output of a power plant over a period of time and its output if it had operated at full nameplate capacity the entire time.
DEMAND RESPONSE

Recognizing that electricity demand is responsive to the real time price of electricity, the AESO offers a combination of programs to allow load to participate in the wholesale electricity market and contribute to reliable system operation.

Approximately 175 to 300 MW of load participates in the market by voluntarily reducing demand when pool prices exceed their self-defined price threshold. Load also has the opportunity to participate in the supplemental reserve market by reducing demand when directed by the AESO following a significant loss of generation in Alberta.

In addition, the AESO offers a demand opportunity service rate for transmission customers who are able to reduce demand when transmission capacity is restricted.

The AESO is currently working with stakeholders to develop an enhanced load shed service for imports (LSSI) to support import capability on the system and increase maximum utilization of interties. Several other demand response initiatives will be explored in 2011, including a potential voluntary load shed service for use under supply shortfall conditions and the integration of demand-side resources into potential new ancillary service products.

HIGHLIGHTS OF THE 24-MONTH RELIABILITY OUTLOOK

Alberta’s Interconnected Electric System will continue to provide an adequate level of reliability using the AESO’s operating practices and procedures. However, the level of congestion on the system is expected to increase in some regions until more transmission is built.

The AESO’s priority is timely approval and implementation of proposed transmission upgrades to meet future reliability needs.

Supply reserve margins will be adequate during the next two years. Close coordination of generator and transmission outages is required to ensure adequate supply and to avoid constraint events during real-time operation.

Emphasis will remain on operating procedures, system analysis and the availability of training and tools to equip system controllers to manage the reliability of the Alberta system.
In Summary

Information in the 24-Month Reliability Outlook 2010 – 2012 is provided from the perspective of assessing the AESO's ability to reliably operate the AIES over the 2010/2011 winter season and the next two years. The 24-Month Reliability Outlook 2010 – 2012 is published every year at the beginning of each winter operating season. Supporting information and forecasts referred to throughout this document are available at www.aeso.ca.

This document complements the AESO’s existing publications and supports our commitment to sharing information with market participants, stakeholders and all Albertans in a timely, open and transparent manner. Readers are invited to provide comments or suggestions for future reports.

For more information or to give us your feedback, contact:
corporate.communications@aeso.ca
Table of Contents

Executive Summary 1

2010 Annual Average Pool Price, $50.88/MWh 2
- Table 1 – Annual Pool Price Statistics – 2001 to 2010 2
- Figure 1 – Monthly Average Hourly Pool Price from 2001 to 2010 with On/Off Peak Averages 2
- Figure 2 – Pool Price Contribution to Total Revenue by Asset Type and Pool Price Range 3
- Figure 3 – Annual Average Pool Price, AECO Natural Gas Price and Heat Rate 4

2.6 Per Cent Demand Growth in 2010 5
- Table 2 – Annual System Demand Statistics 5
- Figure 4 – Monthly Average AIL and Load Growth 5
- Temperatures Drive Peak Demand in Summer and Winter 6
- Figure 5 – Summer and Winter Peak Demand vs. Temperature 7

Supply Adequacy Drives Prices 8
- Figure 6 – Monthly Average Supply Cushion and Pool Price 8
- Figure 7 – Impact of System Constraints on Price – April and May 2010 9
- Figure 8 – Monthly Average Generation Outages and Derates 10

Nearly 270 MW of New Supply Added in 2010 11
- Figure 9 – Generation Additions and Retirements, 2001 to 2010 11
- Figure 10 – Annual Reserve Margin and Peak Alberta Internal Load (AIL) 12

Price Setting and Generation Share in the Market 13
- Figure 11 – Production and Price Setting Share 13
- Demand Participation Increases 14
- Figure 12 – Load Participation in Demand Response Programs 14

Wind Generation 15
- Figure 13 – Monthly Average Wind Capacity Factor 15

Imports and Exports 16
- Table 3 – Annual Intertie Statistics 16
- Table 4 – Intertie Annual ATC Statistics 16
- Figure 14 – Import and Export Utilization on the B.C. Intertie – 2006 to 2010 17

Dispatch Down Service 18
- Table 5 – DDS Annual Statistics 18
- Figure 15 – Total DDS and TMR Dispatched with Total DDS Offers 19
- Figure 16 – Dispatch Down Service Participation 19

Payments to Suppliers on the Margin 20
- Table 6 – Annual Payments to Suppliers on the Margin Statistics 20
- Figure 17 – Total Uplift Payments and the Average Range between Maximum SMP and the Pool Price 20

Operating Reserve Markets 21
- Table 7 – Annual Average Operating Reserve Prices 21
- Figure 18 – OR Reserve Requirements 22
- Move to D-1 does not Impact Market Liquidity 22
- Figure 19 – Day Minus One Market Liquidity 23
- Market Share of Reserves Remain Stable 24
- Figure 20 – Market Share of Operating Reserve by Fuel Type 24

Final Notes and Market Monitoring in 2011 25
Executive Summary

As an independent system operator, the AESO leads the safe, reliable and economic planning and operation of Alberta's interconnected power system. The AESO also facilitates Alberta's fair, efficient and openly competitive wholesale electricity market. In 2010, the Alberta market had about 175 participants and approximately $5 billion in annual energy transactions.

The annual market statistics report provides a summary of key market information from 2010 and describes historic trends in Alberta's wholesale electricity market. For the first time, the AESO is also publishing an accompanying data file to provide stakeholders access to the information behind the metrics presented in this summary report.

The annual average pool price for wholesale electricity was $50.88/MWh in 2010, an increase of six per cent over the 2009 average pool price of $47.81/MWh. The annual average AECO/NIT natural gas price remained relatively unchanged, averaging $3.76/GJ in 2009 and $3.79/GJ in 2010. The increase in pool price contributed to a four per cent increase in the market heat rate, from 13.15 GJ/MWh in 2009 to 13.69 GJ/MWh in 2010. Pool prices were relatively low for all months in 2010 and comparable to those observed in 2009, with the exception of the month of May 2010 which had a monthly average pool price of $134.69/MWh. During the month of May various planned and unplanned transmission and coal-fired unit outages resulted in a reduction of available supply. Tight supply and demand balance contributed to the high pool prices that occurred during the month.

In 2010 Alberta Internal Load (AIL) grew 2.6 per cent over 2009, the highest annual average growth observed since 2006. The primary factors that led to this growth were an increase in demand in major urban centres in the province, economic recovery impacting demand growth in several industries, and high industrial demand growth in northeastern Alberta.

There were nearly 270 MW of new generation capacity added to the Alberta grid in 2010, with the majority of the additions comprised of three new wind power facilities totalling 214 MW. The last remaining unit at the Wabamun coal power plant was retired in 2010. The 279 MW Wabamun 4 coal-fired plant initially commissioned in 1967 was officially retired on March 31, 2010.
2010 Annual Average Pool Price, $50.88/MWh

In Alberta’s competitive wholesale market electricity prices fluctuate based on the principles of supply and demand. During instances of supply surplus and low to moderate demand prices are low, while times of supply scarcity and high demand drive higher prices. The wholesale electricity price, known as the pool price, ranges from the price floor of $0/MWh to the price cap of $999.99/MWh. In 2010, pool price averaged $50.88/MWh, a six per cent increase over 2009. On-peak and off-peak pool prices averaged $66.13/MWh and $31.42/MWh respectively. Table 1 summarizes the historical price statistics from 2000 to 2010. In 2010, prices were similar to those observed in 2009 due to robust supply in the province, as well as continued low natural gas prices. Natural gas prices averaged $3.79/GJ in 2010.

### TABLE 1 – ANNUAL POOL PRICE STATISTICS – 2001 TO 2010

<table>
<thead>
<tr>
<th>Pool Price ($/MWh)</th>
<th>2001</th>
<th>2002</th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average hourly pool price</td>
<td>71.29</td>
<td>43.93</td>
<td>62.99</td>
<td>54.59</td>
<td>70.36</td>
<td>80.79</td>
<td>66.95</td>
<td>89.95</td>
<td>47.81</td>
<td>50.88</td>
</tr>
<tr>
<td>Off-peak average pool price</td>
<td>53.14</td>
<td>28.47</td>
<td>46.97</td>
<td>41.88</td>
<td>49.28</td>
<td>50.15</td>
<td>41.86</td>
<td>54.45</td>
<td>30.26</td>
<td>31.42</td>
</tr>
<tr>
<td>On-peak average pool price</td>
<td>85.51</td>
<td>56.04</td>
<td>75.54</td>
<td>64.53</td>
<td>86.86</td>
<td>104.97</td>
<td>86.61</td>
<td>117.73</td>
<td>61.56</td>
<td>66.13</td>
</tr>
<tr>
<td>Maximum hourly pool price</td>
<td>879.20</td>
<td>999.00</td>
<td>999.99</td>
<td>998.01</td>
<td>999.99</td>
<td>999.99</td>
<td>999.99</td>
<td>999.99</td>
<td>999.99</td>
<td>999.99</td>
</tr>
<tr>
<td>Minimum hourly pool price</td>
<td>5.82</td>
<td>0.01</td>
<td>7.07</td>
<td>0.00</td>
<td>4.66</td>
<td>5.42</td>
<td>0.00</td>
<td>0.10</td>
<td>0.00</td>
<td>0.00</td>
</tr>
</tbody>
</table>

Note: On-peak hours refer to hour ending 08:00 through to hour ending 23:00, Monday through Saturday excluding holidays. Off-peak hours refer to hour ending 01:00 through hour ending 07:00, as well as hour ending 24:00, Monday through Saturday, all day Sunday and all day on North American Electric Reliability Corporation (NERC) defined holidays.

As seen in Figure 1, with the exception of May 2010, pool prices were relatively low and flat throughout the year. During the month of May, unplanned and planned transmission outages significantly reduced the supply availability of certain coal-fired units. Coal-fired generators typically offer most of their energy at lower prices. The reduction in availability of low priced coal-fired generation during May resulted in high pool prices during the month. Excluding May 2010, the pool price averaged $43.10/MWh throughout the rest of the year.

In conditions of supply shortfall the system controllers use a series of mitigation steps to help alleviate the situation. These steps are documented in Operating Policy and Procedure (OPP) 801. In 2010 there were four separate supply shortfall events during which the price cap of $999.99/MWh was reached, all occurring during the month of May. These events occurred from May 16 to 18 due to high levels of planned and unplanned outages to coal-fired units, with an average hourly amount of 2,016 MWh of coal unavailable during these days.

In 2010, the pool price dropped to the price floor of $0/MWh on July 4, 2010 in hour ending 7. This was the first time since June 2008 that the pool price settled at the price floor. On July 4, 2010, the system marginal price remained at the price floor for 83 minutes from 5:37 a.m. to 7:00 a.m. This was due to a number of factors, including high wind generation, low system demand and high coal availability.
The Alberta pool price is determined by the highest priced generator dispatched to meet the demand for electricity. Generators submit hourly offers to the AESO that include the amount of energy they will provide at a specific price. The AESO’s automated Energy Trading System arranges all the hourly offers from the lowest to the highest price. Starting at the lowest priced offer, the AESO system controllers dispatch generating units until the demand requirement is satisfied. The highest priced unit that is dispatched is said to be on the margin, and sets the system marginal price. The pool price is set based on the hourly average of all system marginal prices in the hour.

Natural gas-fired generators are on the margin a significant portion of the time, particularly during on-peak periods. The offer prices made by natural gas-fired generators in the middle of the energy market merit order tend to fluctuate reflecting changes in the price of their underlying fuel. When natural gas prices rise, offers tend to reflect the higher cost, which tends to result in an increase in pool price.

Figure 2, on the following page, presents the breakdown of revenue by pool price range for different asset types. As seen in the graph, the per cent contribution to the annual average pool price was highest in the $0/MWh to $100/MWh range.

The numbers shown within the bars represent the average pool price received by asset type. For example, gas-fired generators received $62.06/MWh on average over all hours, 22 per cent higher than the average pool price. This is because gas-fired generators typically offer to run at higher prices than baseload coal-fired generation. Wind generation, which is a price taker (meaning that wind generation is effectively offered at $0/MWh), tends to receive lower prices per megawatt hour because it displaces higher cost gas generation and reduces the pool price. In 2010, wind generators on average received $38.08/MWh, a 25 per cent discount to the annual average price.
Natural gas prices continued to be low in 2010. Figure 3 shows the historic relationship between natural gas prices and the pool price. The market heat rate refers to the market price of electricity expressed as a function of the market price of the underlying fuel used to produce electricity. In Alberta’s case, this fuel is natural gas.

FIGURE 3
Annual Average Pool Price, AECO Natural Gas Price and Heat Rate
2.6 Per Cent Demand Growth in 2010

After three years of relatively flat load growth, total Alberta internal load (AIL) grew 2.6 per cent in 2010. The highest monthly year-over-year load growth of 6.5 per cent occurred in November 2010 and only March 2010 saw a monthly year-over-year decline, with load declining 0.2 per cent compared to March 2009. Increased demand in major urban centres and industrial demand growth in northeastern Alberta were the primary contributors to this growth.

### TABLE 2 – ANNUAL SYSTEM DEMAND STATISTICS

<table>
<thead>
<tr>
<th>Year</th>
<th>2001</th>
<th>2002</th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total energy (GWh)</td>
<td>54,464</td>
<td>59,428</td>
<td>62,714</td>
<td>65,260</td>
<td>66,267</td>
<td>69,371</td>
<td>69,661</td>
<td>69,914</td>
<td>71,723</td>
<td></td>
</tr>
<tr>
<td>Average hourly load (MWh)</td>
<td>6,217</td>
<td>6,784</td>
<td>7,159</td>
<td>7,429</td>
<td>7,565</td>
<td>7,919</td>
<td>7,952</td>
<td>7,963</td>
<td>7,981</td>
<td>8,188</td>
</tr>
<tr>
<td>Maximum hourly load (MWh)</td>
<td>7,934</td>
<td>8,570</td>
<td>8,786</td>
<td>9,236</td>
<td>9,580</td>
<td>9,661</td>
<td>9,701</td>
<td>9,806</td>
<td>10,236</td>
<td></td>
</tr>
<tr>
<td>Minimum hourly load (MWh)</td>
<td>5,030</td>
<td>5,309</td>
<td>5,658</td>
<td>6,017</td>
<td>6,104</td>
<td>6,351</td>
<td>6,440</td>
<td>6,411</td>
<td>6,454</td>
<td>6,641</td>
</tr>
<tr>
<td>Year-over-year load growth (%)</td>
<td>0.8</td>
<td>9.1</td>
<td>5.5</td>
<td>4.1</td>
<td>1.5</td>
<td>4.7</td>
<td>0.4</td>
<td>0.4</td>
<td>0.0</td>
<td>2.6</td>
</tr>
<tr>
<td>Year-over-year load growth (adjusted for leap year effect) (%)</td>
<td>1.0</td>
<td>9.1</td>
<td>5.5</td>
<td>3.8</td>
<td>1.8</td>
<td>4.7</td>
<td>0.4</td>
<td>0.1</td>
<td>0.2</td>
<td>2.6</td>
</tr>
<tr>
<td>Load factor (%)</td>
<td>78.4</td>
<td>79.2</td>
<td>81.5</td>
<td>80.4</td>
<td>79.0</td>
<td>82.0</td>
<td>82.0</td>
<td>81.2</td>
<td>78.0</td>
<td>80.3</td>
</tr>
</tbody>
</table>

Primary load growth in Alberta’s northeast was due to the continuing expansion of oilsands in the Fort McMurray and Cold Lake areas.

Large urban centres such as Calgary and Edmonton also contributed to Alberta’s overall load growth. Both cities initiated and/or completed large commercial projects in 2010. Calgary’s average load for 2010 was 1,090 MWh (a growth of about 1.3 per cent over 2009) while Edmonton load averaged 864 MWh for 2010 (a growth of about 1.1 per cent over 2009).

### FIGURE 4

Monthly Average AIL and Load Growth
The AESO’s 2009 forecast of demand closely forecast the actual demand observed in 2010. The 2009 forecast, published in late 2009, forecast total AIL energy for 2010 to be 72,459 GWh. Actual energy consumption for the year was 71,723 GWh, resulting in a forecast error of -1 per cent. Peak demand was forecast at 10,170 MWh and actual peak demand was only 26 MWh higher at 10,196 MWh, resulting in a forecast error of 0.3 per cent. For reference, the highest recorded peak load in Alberta in 2009 was 10,236 MWh.

A key feature in the growth observed in 2010 was the close to 200 MWh increase in the minimum load after three years where the minimum was around 6,450 MWh. This is indicative of the strong baseload growth observed in 2010. Another key indicator of load growth in the province has been the increase and regularity of hours where demand has exceeded 10,000 MWh. In December 2009, AIL eclipsed 10,000 MWh for the first time. A total of five hours in December 2009 saw AIL above 10,000 MWh, while in November and December 2010, AIL was above 10,000 MWh for a total of 25 hours.

1 Future Demand and Energy Outlook (2009 – 2029)

Temperatures Drive Peak Demand in Summer and Winter

There was no new peak demand set in 2010, although there were substantially more hours where AIL was greater than 10,000 MWh in November and December 2010 as a result of cold weather. Demand typically peaks between 5 p.m. and 6 p.m. in the winter months. The highest demand observed in 2010 of 10,196 MWh occurred during this hour on December 16th, 2010. Temperatures across the province in 2010 were relatively low, averaging -14 degrees Celsius. In comparison, the temperature averaged -30 degrees Celsius in December 2009 when the winter peak reached an all-time record of 10,236 MWh.

For the second summer in a row, a new summer peak was not set. The peak demand during the summer of 2010 was 9,343 MWh, set on July 29 between 1 p.m. and 2 p.m. Summer peak demand, like winter peak demand is driven in part by temperature. The lack of a new summer peak is primarily attributable to the second summer in a row with very few days where temperatures exceeded 30 degrees Celsius. Average temperatures during July and August 2010 were 16 and 15 degrees Celsius respectively.
Figure 5 illustrates the relationship between temperature and daily peak demand in summer and winter respectively. On average, an increase of 1 degree Celsius will see an increase in the AIL peak of 50 MWh during summer months, and in winter months, a decrease of 1 degree Celsius will see AIL peak increase by 30 MWh.

**FIGURE 5**

**Summer and Winter Peak Demand vs. Temperature**

Daily Weekday Summer Peaks vs. Mean AB Temperature at the Time of Peak

Daily Weekday Winter Peaks vs. Mean AB Temperature at the Time of Peak

<table>
<thead>
<tr>
<th>Temperature (Degrees C)</th>
<th>Daily Peak ($/MWh)</th>
<th>Daily Peak ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>7,500</td>
<td>10,000</td>
</tr>
<tr>
<td>5</td>
<td>8,000</td>
<td>9,500</td>
</tr>
<tr>
<td>10</td>
<td>8,500</td>
<td>9,000</td>
</tr>
<tr>
<td>15</td>
<td>9,000</td>
<td>8,500</td>
</tr>
<tr>
<td>20</td>
<td>9,500</td>
<td>8,000</td>
</tr>
<tr>
<td>25</td>
<td>10,000</td>
<td>7,500</td>
</tr>
</tbody>
</table>

- Linear (2008): $y = 50x + 7646$
- Linear (2009): $y = 54x + 7405$
- Linear (2010): $y = 47x + 7896$

- Linear (2008): $y = -36x + 9442$
- Linear (2009): $y = -32x + 9162$
- Linear (2010): $y = -26x + 9066$

2010 Annual Market Statistics
Supply Adequacy Drives Prices

In a well functioning energy-only electricity market, supply adequacy is the key driver of market price and a motivator of investment decisions. During instances of supply surplus, prices are typically low, while times of supply scarcity tend to drive prices higher.

The supply cushion is an indicator of supply adequacy and the market's ability to meet demand. The supply cushion measures the undispatched energy in the energy market merit order using merit order snapshots at the midpoint of the hour. The detailed calculation of supply cushion is as follows:

Supply Cushion = \sum (Available MW - Dispatched MW) + DDS Dispatched – TMR Dispatched

Note: In the equation, DDS stands for dispatch down service and TMR stands for transmission-must-run. Both concepts are explained in the “Dispatch Down Service” section on page 18 of this report.

Figure 6 displays the monthly average supply cushion compared with the monthly average pool price. Months where the supply cushion was low (indicating a tight supply and demand balance) corresponds with high monthly average pool prices. Typically the supply cushion will decrease when there are planned and unplanned outages that affect supply.

FIGURE 6
Monthly Average Supply Cushion and Pool Price

![Graph showing monthly average supply cushion and pool price. The graph includes data points for each month from March 2008 to December 2010. The x-axis represents the months, and the y-axis represents the supply cushion and pool price in dollars per MWh. The graph shows fluctuations in both supply cushion and pool price throughout the period.]
In May 2010, instances of supply scarcity represented by a low monthly average supply cushion drove prices higher, averaging $134.69/MWh for the month. A significant amount of supply from coal-fired generation was unavailable to the market during this time due to unplanned transmission maintenance in southeast Alberta and planned maintenance in the Keephills/Ellerslie/Genesee (KEG) area.

On April 14, 2010, a spring storm in southeast Alberta caused several transmission line outages that resulted in significant constraints to the coal-fired generators in the area and the curtailment of Saskatchewan interconnection imports to manage the constraint. Repair of the impacted lines was completed in June, 2010. In addition to the southeast constraints, the KEG area underwent several planned transmission outages within the same time period, in particular during the months of May and June.

The reduction in coal generation due to the significant constraints on the system resulted in high pool prices during the time frame, with an average pool price of $106.50/MWh from April 14 to June 1 (in comparison to an average price of $42.26/MWh during the rest of the year not including this period). During this timeframe, there were 1,096 hours (93 per cent of all hours in the period) with constraints to generation, resulting in an average hourly amount of constrained energy of 443 MWh for those hours with constrained generation.

**FIGURE 7**

Impact of System Constraints on Prices – April and May 2010

Figure 7 gives the daily average pool price, daily average coal outages and daily average constrained down generation (CDG). Note that the CDG value includes all constraints entered by the system controller, and may include more units than those impacted due to transmission constraints in the KEG and southeast areas, for example constraints to wind generation. As seen in Figure 7, although the latter portion of May had high CDG, prices were lower than those observed from May 3 through May 18. This was due to a number of factors, including higher availability of overall supply (partly due to increased hydro availability during normal spring runoff), and higher availability of coal units.
All generating assets submit a maximum capability (MC) representing the maximum quantity of megawatts the generating asset is physically capable of generating under optimal operating conditions. The available capability (AC) is set to the MC. Each asset must offer its entire MC to the market unless there is an acceptable operational reason (AOR) for reducing AC to a level lower than the MC. The majority of supply in the market is from baseload assets that run nearly all the time. Most baseload assets are coal-fired units, which offer the majority of their energy into the market at $0/MWh to ensure they are dispatched and because they do not have the operational flexibility to be dispatched below a unit’s minimum generation level. When these baseload assets are unavailable due to planned or unplanned outages, prices tend to increase as generation from gas-fired units and hydroelectric facilities, which tend to have a higher offer price, are required to meet demand.

Figure 8 illustrates the relationship between outages (defined as the difference between the MC and AC) by fuel type and the pool price. In addition to planned and unplanned outages, there are a few periods when a generating asset is available to run based on its operational situation but is constrained from providing all its available generation to the market due to transmission maintenance. As seen in the figure, in May 2010 there was approximately 1,500 MWh of coal-fired generation unavailable, and the pool price averaged $134.69/MWh.

**FIGURE 8**
Monthly Average Generation Outages and Derates
Nearly 270 MW of New Supply Added in 2010

In 2010, nearly 270 MW of new supply was added to the system. This included three new wind generators adding 214 MW to the existing wind installed capacity of 563 MW. Also, a 15 MW cogeneration unit was connected to the grid in 2010. The last remaining unit at Wabamun coal power plant, Wabamun 4, was retired in 2010. The 279 MW coal-fired plant initially commissioned in 1967 was officially retired on March 31, 2010.

**FIGURE 9: Generation additions and retirements, 2001 to 2010**

Figure 9 above indicates that there has been continued growth in new supply in 2010. The reserve margin is a metric that can be used to assess if supply has been adequate in meeting demand. The reserve margin estimates the amount of firm generation capacity at the time of system peak that is in excess of annual peak demand, expressed as a percentage of the system peak. Firm generation is defined as installed generation capacity, adjusting for seasonal hydro capacity and behind-the-fence demand and generation, and excludes wind capacity.
The metric is graphed with and without intertie capacity since full import capability may not always be available at the time of system peak demand. Figure 10 shows that 2010 saw a healthy reserve margin indicating that there was adequate supply to meet demand. The reserve margin including intertie capacity increased from 28 per cent in 2009 to 31 per cent in 2010. The increase in reserve margin is in response to generator additions, a slight decline in peak load, and changes to the capacity values used to perform the calculation.

2 The reserve margin statistics here are based on the quarterly Long Term Adequacy (LTA) Metrics that include annual reserve margin with a five year forecast period.

3 On Nov. 1, 2010 the AESO updated the Current Supply and Demand report capacity values to reflect maximum capability as the capacity. Prior to that date capacity values were based on the generating unit’s maximum continuous rating.

FIGURE 10
Annual Reserve Margin and Peak Alberta Internal Load (AIL)
Price Setting and Generation Share in the Market

Coal-fired generation production provides the majority of the energy required by Alberta's market. In 2010, coal-fired generators provided 71.1 per cent of the energy consumed. This represents a 1.4 per cent reduction from 2009 due to increased coal-fired unit outages and derates in 2010 and the retirement of Wabamun 4. Gas and cogeneration units provided 18.7 per cent of the energy consumed and wind generation provided 2.8 per cent, an increase of one per cent and 0.2 per cent over 2009 respectively. The amount of energy provided by hydroelectric generation declined 0.2 per cent year-over-year, from 2.9 per cent in 2009 to 2.7 per cent in 2010.

Coal-fired generating units set price 50 per cent of the time in 2010, a 10 per cent decrease from 2009. The amount of time that natural gas-fired units set price increased from 39 per cent to nearly 50 per cent of the time in 2010. The offer prices of natural gas-fired generation typically track the price of the underlying fuel, natural gas. Higher gas prices result in higher offer prices by natural gas-fired units. In 2010, natural gas prices continued to be low, which led to a reduction in the offer prices of natural gas-fired units. Therefore, the annual average pool price was relatively low despite the increased amount of time that natural gas-fired units were on the margin.

FIGURE 11
Production and Price Setting Share
Energy Production by Fuel Type

Price Setters by Fuel Type

FIGURE 11
Annual Average Pool Price

2010 Annual Market Statistics
Demand Participation Increases
The AESO has a particular interest in examining how demand response programs can assist in managing reliability and contribute to a fair, efficient and openly competitive electricity market. In Alberta, large industrial customers are directly connected to the transmission system and may be exposed to the hourly volatility of pool price. Many of these customers participate in some form of demand response varying from voluntarily reducing consumption when prices increase to providing some form of reliability product to the AESO. In 2010 there was an increase in the amount of load that qualified for demand opportunity service, which is a temporary, interruptible class of transmission service. There was also an increase in the amount of loads participating in the supplemental reserves market.

FIGURE 12
Load Participation in Demand Response Programs

<table>
<thead>
<tr>
<th>MW</th>
<th>0</th>
<th>Q1</th>
<th>Q2</th>
<th>Q3</th>
<th>Q4</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Qualified DOS Providers</td>
<td>Active Supplemental Reserves Providers</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Participants in Supplemental Reserves who also Respond to Price</td>
<td>Participants in the Load Shed Service who also Respond to Price</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Loads that Respond to Price</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Legend:
- Red: Qualified DOS Providers
- Blue: Active Supplemental Reserves Providers
- Green: Participants in Supplemental Reserves who also Respond to Price
- Orange: Participants in the Load Shed Service who also Respond to Price
- Yellow: Loads that Respond to Price
Wind Generation

In 2010 there was continued growth in wind installed capacity with the addition of three new wind farms. The addition of Summerview II, Ardenville and Ghost Pine wind farms added 214 MW to the province’s existing 563 MW of wind installed capacity in southern Alberta. The aggregate capacity factor for wind power facilities compares the total energy production over a period of time with the amount of power the plant would have produced at full capacity. Wind capacity factor in 2010 averaged 28 per cent, which is lower than the 2009 average of 33 per cent.

FIGURE 13
Monthly Average Wind Capacity Factor
Imports and Exports

Alberta has interties to both provincial neighbors. These interties allow energy to be imported during times of tight supply and exported during periods of energy surplus. During the course of the year the amount of imports and exports will vary depending on the limitations of the interties, market prices for electricity in other jurisdictions, and other factors. Total imports on the B.C. intertie increased in 2010 by 37 per cent as compared to the previous year.

<table>
<thead>
<tr>
<th>TABLE 3 – ANNUAL INTERTIE STATISTICS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Intertie statistics (GWh)</td>
</tr>
<tr>
<td>--------------------------------------</td>
</tr>
<tr>
<td>Imports on B.C. intertie</td>
</tr>
<tr>
<td>Imports on Saskatchewan intertie</td>
</tr>
<tr>
<td>Total imports</td>
</tr>
<tr>
<td>Year-over-year growth (%)</td>
</tr>
<tr>
<td>Exports on B.C. intertie</td>
</tr>
<tr>
<td>Exports on Saskatchewan intertie</td>
</tr>
<tr>
<td>Total exports</td>
</tr>
<tr>
<td>Year-over-year growth (%)</td>
</tr>
<tr>
<td>Net yearly imports</td>
</tr>
</tbody>
</table>

The available transfer capability (ATC) is the amount of electricity that can flow on the interties. In 2010, both the maximum B.C. import ATC and average B.C. import ATC increased over 2009. The Saskatchewan maximum import ATC remained unchanged at 153 MW, while the average import ATC declined 32 MW due to the spring storm in southeast Alberta that caused various transmission constraints in the area. To manage the constraints, the Saskatchewan intertie import ATC was set to zero. In 2010 both the maximum and average export ATC on the Saskatchewan intertie increased as compared to 2009.

<table>
<thead>
<tr>
<th>TABLE 4 – INTERTIE ANNUAL ATC STATISTICS (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>B.C. export ATC</td>
</tr>
<tr>
<td>Year</td>
</tr>
<tr>
<td>------</td>
</tr>
<tr>
<td>2006</td>
</tr>
<tr>
<td>2007</td>
</tr>
<tr>
<td>2008</td>
</tr>
<tr>
<td>2009</td>
</tr>
<tr>
<td>2010</td>
</tr>
</tbody>
</table>

Utilization of the import ATC on the B.C. intertie is defined as the import amount net of any exports for each hour, plus any operating reserves being provided over the intertie divided by the ATC:

\[
\text{Import utilization} = \frac{(\text{import}_{t} - \text{export}_{t}) + \text{reserves}}{\text{ATC}}
\]

The export utilization is the export amount net of any imports divided by the export ATC:

\[
\text{Export utilization} = \frac{(\text{export}_{t} - \text{import}_{t})}{\text{ATC}}
\]
In 2010, there was an increase in the amount of time that the B.C. intertie was highly utilized (greater than 80 per cent utilization). Imports flow in response to market opportunities in Alberta and in doing so, enhance system reliability in times when there is insufficient supply within the province to meet demand. Figure 14 illustrates the amount of time the B.C. intertie was utilized over the past five years. During 2010 imports on the B.C. intertie occurred 67 per cent of the time, and 27 per cent of the time import utilization of ATC exceeded 80 per cent. Exports on the B.C. intertie occurred 22 per cent of the time, with export utilization exceeding 80 per cent four per cent of the time.

**FIGURE 14**
Import and Export Utilization on the B.C. Intertie – 2006 to 2010
Import Utilization Adjusted to Account for Reserves on the Intertie
Dispatch Down Service

Transmission-must-run (TMR) dispatches occur when a generator is constrained on to operate at a minimum specified MW output level in order to maintain system security. Dispatching TMR displaces in merit energy and results in a downward effect on the pool price. The dispatch down service (DDS) is a price adjustment mechanism that negates the downward effect TMR dispatches have on the pool price. This service was introduced in December 2007 and is intended to improve the pool price signal.

DDS payments in 2010 totaled $8 million for 538 GWh of DDS dispatched. This service was used to offset 792 GWh of TMR dispatches. The total DDS payment in 2010 was 42 per cent lower than in 2009 ($13 million) due to reductions in the amounts of TMR and DDS dispatched. Total TMR dispatched in 2010 was reduced 22 per cent from 2009, and total DDS dispatches reduced 34 per cent year over year.

### TABLE 5 – DDS ANNUAL STATISTICS

<table>
<thead>
<tr>
<th>Year</th>
<th>TMR Dispatched (GWh)</th>
<th>DDS Dispatched (GWh)</th>
<th>Average DDS Charge per MWh ($/MWh)</th>
<th>Total DDS Payments ($ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>983</td>
<td>731</td>
<td>0.46</td>
<td>28</td>
</tr>
<tr>
<td>2009</td>
<td>1,018</td>
<td>810</td>
<td>0.23</td>
<td>13</td>
</tr>
<tr>
<td>2010</td>
<td>792</td>
<td>538</td>
<td>0.13</td>
<td>8</td>
</tr>
</tbody>
</table>

The costs of providing the DDS service are allocated to suppliers (generators and imports) by metered volumes in a manner that is effectively a “financial pro-rata” among suppliers who generated during a settlement interval. In 2010, the average DDS charge was $0.13/MWh, down 10 cents from 2009.

The amount of DDS required is directly related to the amount of TMR on the system. Eligibility for dispatching DDS is also determined by the system marginal price. If the system marginal price is greater than the TMR reference price, then no DDS is dispatched. Furthermore, any system constraints that result in generation being constrained down offset the need for DDS.

Due to system constraints in April, May, and June of 2010, and the resulting generation that was constrained, the amount of DDS required was significantly lower than the amount of TMR dispatched during the same period. In 2010, the system marginal price was less than the TMR reference price 86 per cent of the time. The combined effect of the amount of time the DDS was eligible and the amount of generation constrained down resulted in 68 per cent of TMR dispatches being offset by DDS dispatches.
There continues to be sufficient interest in the DDS market with nearly all hours having surplus DDS offers to offset the amount of TMR dispatched. A total of 10 participants offered into the DDS market in 2010, unchanged from the year before. Gas-fired units continue to be the predominant provider of DDS, receiving 75 per cent of the dispatches in 2010.
Payments to Suppliers on the Margin

Payments to suppliers on the margin, also known as uplift, is a settlement rule intended to address the discrepancy between the dispatch and settlement intervals. The payment provides generators the opportunity to receive payments based on their actual offer prices instead of the settled pool price, which may have settled lower than their offer that received a dispatch in a particular settlement interval.

**TABLE 6 – ANNUAL PAYMENTS TO SUPPLIERS ON THE MARGIN STATISTICS**

<table>
<thead>
<tr>
<th>Year</th>
<th>Total Uplift Payments ($ millions)</th>
<th>Average Range between the maximum SMP and the pool price ($/MWh)</th>
<th>Average Charge ($/MWh)</th>
<th>Total Market Value* ($ millions)</th>
<th>% of Market Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>3.5</td>
<td>26.81</td>
<td>0.06</td>
<td>5,178</td>
<td>0.07</td>
</tr>
<tr>
<td>2009</td>
<td>1.2</td>
<td>10.29</td>
<td>0.02</td>
<td>2,734</td>
<td>0.05</td>
</tr>
<tr>
<td>2010</td>
<td>1.5</td>
<td>10.60</td>
<td>0.03</td>
<td>2,884</td>
<td>0.05</td>
</tr>
</tbody>
</table>

* Total market value equals the sum of AIES load metered volumes multiplied by pool price

In 2010, uplift payments totaled $1.5 million, a 17 per cent increase over the 2009 total of $1.2 million. This increase is partially due to a slight increase in the average pool price, but is also due to an increase in the average range between pool price and the maximum system marginal price in the hour, which is a measure of intra-hour volatility and a driver of uplift payments (as seen in Figure 17). In 2010, the difference between the maximum SMP in a settlement interval and the pool price averaged $10.60/MWh, while in 2009 the difference averaged $10.29/MWh.

**FIGURE 17**

Total Uplift Payments and the Average Range between Maximum SMP and the Pool Price
Operating Reserve Markets

The prices paid to providers of operating reserve (OR) are indexed to pool price. Therefore, the prices in the operating reserve market trend closely to changes in pool price. The AESO procures active and standby reserve. The purpose of active reserve is to meet the requirements of the AIES under normal operating conditions and the purpose of standby reserve is to provide replacement or additional reserve should there be a need. All active reserve is priced based on an index to pool price. Standby pricing involves both a premium and activation price. The premium price is the price paid to the OR provider which gives the AESO the option to call on the reserve if required. The activation price is the price paid to the provider if the option is dispatched.

In 2010, prices in the OR markets increased from the previous year in part due to the overall increase in pool price, as well as the constraints caused by the storm damage in southeastern Alberta as discussed on page 9. OR costs for May alone were $47 million or 34 per cent of the total 2010 OR costs. Table 7 provides a historical summary of prices in both the active and standby markets. Regulating reserve is used for real-time balancing of supply and demand and requires automatic control of generation levels to ensure the grid is operated reliably. Due to the significant requirements of this product, it is priced higher than the other two types of reserves. Spinning reserve and supplemental reserve are used to maintain the balance of supply and demand when an unexpected system event occurs. Spinning reserve must be synchronized to the grid. Both of these products are priced lower than regulating reserve, with spinning reserve priced slightly higher than supplemental reserve.

<table>
<thead>
<tr>
<th>Active</th>
<th>Standby premiums</th>
<th>Standby activation</th>
<th>Total OR Cost ($ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>RR SR</td>
<td>RR SR SUP</td>
<td>RR SR SUP</td>
<td></td>
</tr>
<tr>
<td>2006</td>
<td>34 30 29</td>
<td>4 4 3</td>
<td>84 85 84</td>
</tr>
<tr>
<td>2007</td>
<td>34 29 26</td>
<td>5 4 4</td>
<td>101 101 96</td>
</tr>
<tr>
<td>2008</td>
<td>51 43 38</td>
<td>7 5 5</td>
<td>163 151 133</td>
</tr>
<tr>
<td>2009</td>
<td>23 16 11</td>
<td>5 4 3</td>
<td>96 85 69</td>
</tr>
<tr>
<td>2010</td>
<td>27 21 16</td>
<td>7 4 4</td>
<td>141 115 91</td>
</tr>
</tbody>
</table>

The amount of active OR varies depending on the reserve type and also the time of day. The regulating reserve requirement is influenced primarily by changes to intertie schedules and the short-term AIL forecast. Both spinning and supplemental reserve are used for contingency purposes and the criteria for determining the requirement is primarily based on the load levels in Alberta. Figure 18 on the following page illustrates typical reserve requirements.

The AESO procure the majority of active reserve using an online exchange called Watt-Ex. On Watt-Ex the AESO procures OR using on and off-peak blocks. The amounts of these blocks are based on the minimum amount of reserve required in each period. In Figure 18 on the following page, the yellow area of the graph represents the off-peak volumes procured over Watt-Ex, while the orange area represents on-peak volumes procured. The remainder of the OR requirement is then procured using over-the-counter contracts (OTC). In 2010, six per cent of the active OR requirement was procured using OTC.
Move to D-1 does not Impact Market Liquidity

Operating reserve is procured one day in advance of when it is required. This timing is referred to as “day minus one” or “D-1”. Prior to July 2010, operating reserve was procured up to five days in advance of delivery. However, the procurement period was reduced to D-1 procurement after July 2010 as part of the AESO’s ongoing efforts to improve the design of the operating reserve market.

Operating reserve market liquidity can be measured by comparing the amount of offers to the AESO’s bid for OR products to determine the MW remaining in the active market. The liquidity measures for all on and off-peak active markets on D-1 indicate that there has been little difference between the time the AESO moved to 100 per cent D-1 procurement (July 2010) and before.
FIGURE 19
Day Minus One Market Liquidity
Regulating Reserve Day Minus One Market Liquidity

Spinning Reserve Day Minus One Market Liquidity

Supplemental Reserve Day Minus One Market Liquidity
Market Share of Reserves Remain Stable
In 2010, 63 per cent of active regulating reserve required was provided by hydroelectric generators. Hydro assets also provided 57 per cent of supplemental reserve and 43 per cent of spinning reserve. Gas-fired generation provided almost all of the remaining regulating reserve and coal-fired units provided three per cent of regulating reserve. Spinning reserve market share was unchanged from the previous year with gas, hydro, and intertie capacity providing the majority of spinning reserve. Generators and loads are able to participate in the supplemental reserve market. In 2010, load increased its market share in the supplemental market from eight per cent in 2009 to nine per cent in 2010.

FIGURE 20
Market Share of Operating Reserve by Fuel Type
Final Notes and Market Monitoring in 2011

As the market evolves throughout 2011 and beyond, the AESO will continue to monitor, analyze, and report on market outcomes. As part of this monitoring process, the AESO provides real-time, historical and forecast reports and metrics on the market. These include daily and weekly reports outlining energy and operating reserve market statistics and a broad selection of historical datasets. The AESO appreciates comments and questions from stakeholders on this report.

Should market participants have any questions on this report, or have a market analysis question, please contact market.analysis@aeso.ca
Appendix D: Part 1
FC2009 Overlay

SUMMARY

The purpose of this summary is to review and examine the FC2009 forecast, its assumptions and appropriateness for use in the Long-term Transmission Plan (filed June 2012) – also referred to as the LTP or the Plan. The FC2009 was completed in late 2009, released in early 2010 and used as a key input into this LTP.

As this document shows, the key assumptions used in the creation of the FC2009 remain valid and its thesis that strong investment in the oilsands industry will spur economic development and job growth and corresponding load growth has not changed.

OBJECTIVE OF THE FC2009 FORECAST

Future Demand and Energy Outlook (2009-2029) (FC2009) is the AESO’s long-term load forecast. The FC2009 forecast is used as a key input into generation scenario development and transmission planning. Due to the long life span of transmission infrastructure, it is important that the FC2009 adequately capture long run developments and technological trends so that appropriate levels of transmission are developed.
METHODOLOGY

The FC2009 forecast used econometric, top-down, and bottom-up models to forecast electricity usage on a customer sector basis. The methodology provides a consistent and balanced approach to load forecasting through the use of a combination of fitted statistical models, historical data, third-party economic forecasts and customer-specific information.

The AESO’s models are consistent with industry standards for forecasting electricity demand and are customized to fit Alberta’s unique characteristics. As part of its forecasting processes, the AESO reviews modeling techniques as well as models specification types in order to ensure that appropriate models are created and used. The model specifications are based upon a combination of available forecast and historical data as well as customer sector-specific electricity demand drivers and trends. Statistical modeling techniques and back casts are used to confirm the statistical validity of the models.

Key inputs into the AESO’s models come from third party forecasting agencies including The Conference Board of Canada and the Canadian Association of Petroleum Producers (CAPP). The AESO does not have the resources required to create forecasts of key input variables such as 20 year GDP forecasts so it relies on external, publicly available forecasts which can be reviewed by stakeholders.

As part of its processes, the AESO assesses the validity of the forecasts used from third parties. The forecasts are assessed for their overall outlook and assumptions as well as for consistency with other forecasts and consistency with the AESO’s own internal project information. This process helps ensure that the AESO's load forecast is reasonable and robust.

KEY ASSUMPTIONS OF FC2009

The FC2009 forecast is dependent upon the long run outlook for development and economic growth in Alberta. Economic growth, as measured by Gross Domestic Product (GDP), is a key input assumption into FC2009. The AESO uses The Conference Board of Canada's long run provincial forecasts as a basis for this input.

Figure 1 shows assumed GDP growth used in FC2009 for 2009 through to 2020 compared to a number of updated forecasts. FC2009 assumes very strong growth in 2011 and 2012 compared to other forecasts. The AESO assessed the validity of this strong growth when creating the FC2009. At the time, it was deemed reasonable as that strong short term growth was based upon an aggressive, but rapid, economic recovery followed by more modest growth.
The AESO believes the GDP growth assumption used in FC2009 is reasonable. While strong growth is forecasted for 2011 and 2012, it can also be seen in Figure 1 that the GDP growth assumed by FC2009 in 2014 and 2015 is well below other, more recent forecasts. This means that more recent GDP forecast updates expect that growth is still going to occur but slower than was expected in FC2009. Therefore, the GDP growth assumption of FC2009 remains valid; however, the timing of that growth may be delayed by two to three years.

The actual risk of delayed growth is minimal as the FC2009 attempts to capture long run trends, not short term fluctuations. FC2009 assumed annual GDP growth of 3.2 per cent from 2010 to 2020. This forecast is inline with The Conference Board of Canada’s 2010 provincial long run economic forecast of 3.3 per cent as well as IHS Global Insight’s January 2011 forecast of 3.0 per cent over the same timeframe.
The expected economic growth in Alberta is largely based upon the assumption that there will be strong oilsands investment and development. The Conference Board of Canada’s *Provincial Outlook 2009*, which was used as a key input into FC2009, assumed that “some $180 billion will be invested in the development of the oilsands between now and 2020”. This outlook has not changed as Peters and Co., in its recent *Oilsands Overview: Winter 2011*, said “[over the next ten years,] we forecast total risked capital expenditures of $180 billion, with a peak of approximately $22 billion in 2014”. This updated estimate of $180 billion is in addition to over $12 billion invested in the oilsands in 2010. The similarity of oilsands investment outlooks between the time of FC2009 and recently indicates that assumptions used are still valid.

The assumption that strong investment will occur in the oilsands is also confirmed by updated oilsands production forecasts. As Figure 2 shows, the oilsands production forecast used in the FC2009 remains consistent with recent updates.

**Figure 2: FC2009 Oilsands production forecast compared to latest updates**

![Oilsands production forecast graph](image-url)

*Source: PIRA, CAPP*
Another key input into FC2009 is Alberta population growth. In FC2009, it was assumed that strong economic growth, resulting from oilsands development growth would create jobs that incent immigration to Alberta. The latest population forecasts confirm that assumption as Figure 3 shows. Strong population growth is still expected.

**Figure 3: FC2009 Population forecasts compared to latest updates**

The key FC2009 assumptions of GDP growth, oilsands production growth, and population growth all remain inline with the latest forecast updates. Therefore, the AESO believes that key input assumptions used in FC2009 remain valid.
The FC2009 forecasts strong load growth over the next few years despite minimal growth from 2007 to 2009. The AESO believes this is a reasonable expectation given a number of factors. First, 2010 experienced fairly strong load growth as AIL grew by 2.6 per cent. Year to date 2011 is also showing strong load growth. In addition, the AESO has a substantial number of load projects in its connection queue and project list. The sum of the connection request equals to load growth in excess of seven per cent annually over the next five years. This is substantially higher than the growth forecast in FC2009.

The recent accuracy of the FC2009, combined with the consistent validity of its assumptions compared to updated input forecasts, indicates that the forecast remains reasonable and appropriate to use for this LTP.
SUMMARIES OF UNCERTAINTIES

The expected growth in the oilsands industry remains one of the largest sources of forecast uncertainty because of the rapidly growing sector and changing technological trends. The amount of electricity required by oilsands projects tends to vary greatly with reserve quality and other factors.

Often, additional processes are required to maintain production at in situ sites which typically requires additional electric pumps or compressors. Electric pumps are preferred over gas because of their simplicity, reliability, low maintenance, and lower cost. If additional steam needs to be injected, more electricity is used as the steam is injected into the injection wells. Some sites install electrical submersible pumps to offset or replace gas-lift which also increases electricity usage.

New technologies may also increase electricity intensities. E-T Energy is currently testing an electrode technology which would use significantly more electricity than traditional SAGD. Other electricity-based technologies are also being examined such as electric heating coils, electric heating elements, and inductive heating technologies; all of which are likely to increase the amount of electricity required to extract a given barrel of bitumen. Other companies are looking into injecting solvents to assist SAGD. The addition of solvent injection pumps would also add to electricity usage.

Environmental considerations could also increase the electricity intensity of the oilsands. If carbon capture equipment is added to sites, this would increase the electricity usage. Technologies to deal with tailings, such as centrifuge, could increase electricity demand, and additional water recycling processes would also increase electricity consumption.

Additional forecast uncertainty comes from the industrial (without oilsands) sector. This uncertainty was noted in the FC2009 document. The key uncertainty was the forecasted resumption of growth in that sector following several years of decline. As was mentioned in FC2009, this historical decline can be largely attributed to the exit and reduced activities of a limited number of industrial firms in the province. With expectations of increased pipeline volumes due to expanding oilsands, the electricity demand from pipelines will not only return to previous levels but should grow beyond them as well.
So far, it appears that industrial (without oilsands) energy use is growing in line with the FC2009 forecast. As Figure 5 shows, industrial (without oilsands) energy increased in 2010 over 2009, halting a decline trend that existed since 2006. Rebound from the economic recession has increased the demand for commodities and other products which has benefited Albertan industries.

There remains uncertainty over whether industrial energy demand can continue to grow. However, it is intuitive that with the expected investment in the oilsands that there will be demand for industrial activity such as manufacturing processes and pipeline activity. Therefore, the AESO is confident that the FC2009 forecast of Industrial (without oilsands) energy forecast remains valid.

*Figure 5: Historical and forecasted industrial energy (without oilsands) with 95% confidence band*
Another key uncertainty is timing. While there is strong confidence that the large amount of investment in the oilsands will spur economic development, there is far less certainty over the timing of oilsands development. It has been seen in the previous oilsands cycle that labour and material shortages contributed to delays of projects. Fewer projects were actually initiated than were announced. One of the developmental changes of oilsands since the previous cycle is the increase in modularized development. Many projects are as big as they were before but they tend to be developed in smaller stages in order to reduce risk and control costs. The flexibility of modularized development means individual phases of a project could be delayed or restarted quickly.

There is also a strong possibility that labour and/or materials shortages could contribute to development delays again. The Petroleum Human Resources Council of Canada (PHRCC), in its *Petroleum Labour Market Information, Supply/Demand Analysis 2009-2020*, is projecting that employment in the oilsands will more than double from 2008 levels by 2020. At the same time, the PHRCC expects that a significant amount of the existing oilsands workforce will retire in that time. Therefore, it will be a challenge for oilsands producers and developers to obtain the required number of workers. Difficulty in obtaining these workers could result in project delays which could defer oilsands production growth and associated electricity demand growth.

Due to the risks associated with uncertainties, the AESO undertakes measures to ensure that the forecast remains valid. The AESO engages directly with industry, tracks industrial and oilsands development, and monitor's technological and environmental trends and their effect on electrical intensities and electricity demand. This information also feeds into future forecasts and prompts changes to future forecasts if necessary.

**VARIATION BY REGION**

Table 1 shows the regional split of historical 2010 load at time of AIL winter peak plus an estimation of the uncertainty in each region for 2015 and 2020, historically, the most significant growth has come from the Northeast region due to rapidly increasing oilsands related growth. This growth is expected to continue with the strong expected development of the oilsands which explains the strong forecasted growth for the Northeast planning area.

Growth in the Central region is due to the new and expanded pipelines as well as associated infrastructure. This region contains two major corridors for oil export pipelines and load will continue to grow to allow production in the Northeast region to flow to market.

The Northwest region’s largest contributor to growth is industrial load growth around the Fort Nelson area.

Growth in the South region is mainly driven by urban growth in and around Calgary. A strong Alberta economy driven by oilsands development will be reflected in robust urban growth in the major cities in Alberta.
Figure 6: Transmission planning regions
Table 1: Regional load at time of AIL winter peak and load uncertainty by planning region

<table>
<thead>
<tr>
<th>Planning Region</th>
<th>MW</th>
<th>Uncertainty up</th>
<th>Uncertainty down</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Northwest</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010 actual</td>
<td>1,039</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010 forecast</td>
<td>1,099</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2015 forecast</td>
<td>1,332</td>
<td>-15</td>
<td>-360</td>
</tr>
<tr>
<td>2020 forecast</td>
<td>1,536</td>
<td>-160</td>
<td>-490</td>
</tr>
<tr>
<td><strong>Northeast</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010 actual</td>
<td>2,349</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010 forecast</td>
<td>2,197</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2015 forecast</td>
<td>3,281</td>
<td>465</td>
<td>-40</td>
</tr>
<tr>
<td>2020 forecast</td>
<td>4,078</td>
<td>370</td>
<td>-45</td>
</tr>
<tr>
<td><strong>Edmonton</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010 actual</td>
<td>2,093</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010 forecast</td>
<td>2,013</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2015 forecast</td>
<td>2,386</td>
<td>125</td>
<td>-60</td>
</tr>
<tr>
<td>2020 forecast</td>
<td>2,780</td>
<td>65</td>
<td>-90</td>
</tr>
<tr>
<td><strong>Central</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010 actual</td>
<td>1,505</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010 forecast</td>
<td>1,573</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2015 forecast</td>
<td>1,933</td>
<td>160</td>
<td>-45</td>
</tr>
<tr>
<td>2020 forecast</td>
<td>2,251</td>
<td>10</td>
<td>-50</td>
</tr>
<tr>
<td><strong>South</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010 actual</td>
<td>2,917</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010 forecast</td>
<td>2,925</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2015 forecast</td>
<td>3,512</td>
<td>310</td>
<td>-70</td>
</tr>
<tr>
<td>2020 forecast</td>
<td>4,093</td>
<td>130</td>
<td>-110</td>
</tr>
<tr>
<td><strong>AIL</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010 actual</td>
<td>10,226</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010 forecast</td>
<td>10,170</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2015 forecast</td>
<td>12,807</td>
<td>1,050</td>
<td>-580</td>
</tr>
<tr>
<td>2020 forecast</td>
<td>15,162</td>
<td>410</td>
<td>-785</td>
</tr>
</tbody>
</table>

Source: AESO
In preparing these estimations of regional uncertainty, the AESO adjusted a number of factors and only factors that were investigated as a result of recent project applications to the AESO.

For uncertainty upwards, the AESO included recent Distribution Facility Owner (DFO) and project information by site, and included projects with higher in-situ electrical intensities than forecasted in the FC2009. Overall, this sensitivity suggests the potential for more than 1,000 MW higher AIL peak in 2015 and just over 400 MW by 2020.

The uncertainty towards a lower forecast in the 2015 and 2020 timeframe was calculated by holding DFO and project information at the FC2009 level and, as well, sites that can be clearly identified as a single customer and not a conventional oil, oilsands site or associated infrastructure, were dropped to 0 MW. The result on total AIL in this sensitivity is a drop in load of just over 575 MW by 2015 and around 775 MW by 2020.

In summary, the pressures up or down, would result in load occurring within one or two years of the forecast.
# Table of Contents

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Executive Summary</strong></td>
<td>1</td>
</tr>
<tr>
<td><strong>1.0</strong> Introduction</td>
<td>3</td>
</tr>
<tr>
<td><strong>2.0</strong> Economic Outlook</td>
<td>4</td>
</tr>
<tr>
<td>2.1 Alberta’s GDP Growth</td>
<td>4</td>
</tr>
<tr>
<td>2.2 Alberta’s Population Growth</td>
<td>6</td>
</tr>
<tr>
<td>2.3 Oilsands Production Growth</td>
<td>7</td>
</tr>
<tr>
<td><strong>3.0</strong> Methodology</td>
<td>9</td>
</tr>
<tr>
<td>3.1 AESO Methodology Diagram</td>
<td>10</td>
</tr>
<tr>
<td>3.2 Industrial (without Oilsands) Customer Sector</td>
<td>11</td>
</tr>
<tr>
<td>3.3 Oilsands Customer Sector</td>
<td>13</td>
</tr>
<tr>
<td>3.4 Commercial Customer Sector</td>
<td>15</td>
</tr>
<tr>
<td>3.5 Residential Customer Sector</td>
<td>17</td>
</tr>
<tr>
<td>3.6 Farm Customer Sector</td>
<td>19</td>
</tr>
<tr>
<td>3.7 Historical Growth and Decrease in 10 Ten Industrial Sites</td>
<td>21</td>
</tr>
<tr>
<td><strong>4.0</strong> Forecast Results</td>
<td>24</td>
</tr>
<tr>
<td>4.1 Provincial Results – AIL Forecast</td>
<td>25</td>
</tr>
<tr>
<td>4.2 Provincial Results – AIES Forecast with Behind-the-Fence (BTF) Load Estimation</td>
<td>27</td>
</tr>
<tr>
<td>4.3 Provincial Results – Demand Tariff Service (DTS) Energy</td>
<td>29</td>
</tr>
<tr>
<td>4.4 Forecast Results for Bulk Planning Purposes</td>
<td>29</td>
</tr>
<tr>
<td>4.5 Forecast Results for Regional Planning Purposes</td>
<td>32</td>
</tr>
<tr>
<td><strong>5.0</strong> Other Load Forecasting Considerations</td>
<td>36</td>
</tr>
<tr>
<td>5.1 Demand Responsive Load and Conservation</td>
<td>36</td>
</tr>
<tr>
<td>5.2 Composition of Load</td>
<td>38</td>
</tr>
<tr>
<td>5.3 Distributed Generation</td>
<td>39</td>
</tr>
<tr>
<td>5.4 Environmental Costs</td>
<td>39</td>
</tr>
<tr>
<td>5.5 Challenges on the Horizon</td>
<td>40</td>
</tr>
<tr>
<td><strong>6.0</strong> Historical and Past Forecast Results</td>
<td>41</td>
</tr>
<tr>
<td>6.1 Past Forecast Variances</td>
<td>41</td>
</tr>
</tbody>
</table>
Appendix A: Confidence Band Intervals for the Future Demand and Energy Outlook (2009 – 2029) 43

Executive Summary 43

1.0 Introduction 44

2.0 Monte Carlo Analysis 45
  2.1 Industrial (without Oilsands) Customer Sector 46
  2.2 Oilsands Customer Sector 47
  2.3 Commercial Customer Sector 48
  2.4 Residential Customer Sector 49
  2.5 Farm Customer Sector 50

3.0 Total Energy and Peak Demand 51
  3.1 Monte Carlo Results 51

List of Reference Documents 56

Glossary 57

Figures
  Figure 2.1-1: Changes in GDP 5
  Figure 2.2-1: Population Growth in Alberta 6
  Figure 2.2-2: Alberta Population 6
  Figure 2.3-1: Oilsands Bitumen Production Forecast 8
  Figure 2.3-2: Synthetic Crude Oil Production Forecast 8
  Figure 3.0-1: Customer Sector as Percentage of Total Energy (2008) 9
  Figure 3.1-1: AESO Load Forecast Methodology Flow Diagram 10
  Figure 3.2-1: Historical Industrial (without Oilsands) Energy 11
  Figure 3.2-2: Industrial End Use as Percentage of Total Industrial (2006) 12
  Figure 3.2-3: Industrial (without Oilsands) Energy Intensity 12
  Figure 3.2-4: Industrial (without Oilsands) Energy Forecast 13
  Figure 3.3-1: Oilsands Energy Intensity 14
  Figure 3.3-2: Oilsands Energy Forecast 14
  Figure 3.4-1: Historical Commercial Energy Usage 15
  Figure 3.4-2: Commercial Energy and Alberta GDP 15
  Figure 3.4-3: Commercial Energy Intensity 16
  Figure 3.4-4: Commercial Energy Forecast 16
  Figure 3.5-1: Historical Residential Energy Use 17
  Figure 3.5-2: Residential Energy Use Per Capita 18
  Figure 3.5-3: Residential Energy Forecast 18
  Figure 3.6-1: Historical Farm Energy 19
Figure 3.6-2: Agricultural Land in Alberta
Figure 3.6-3: Farm Energy Forecast
Figure 3.7-1: Historical Energy of 10 Industrial Firms
Figure 3.7-2: Historical AIL Energy with Adjustment Factor
Figure 3.7-3: Historical and Forecast AIL Energy Growth
Figure 3.7-4: Alberta GDP Growth Forecasts
Figure 4.4-1: Region Demand at Time of Winter AIL Peak Demand
Figure 4.4-2: Region Demand at Time of Summer AIL Peak Demand
Figure 4.5-1: Grouping of Areas for Regional Planning Purposes
Appendix: Figure 2.1-1: Industrial (without Oilsands) Sector Confidence Intervals
Appendix: Figure 2.2-1: Oilsands Sector Confidence Intervals
Appendix: Figure 2.3-1: Commercial Sector Confidence Intervals
Appendix: Figure 2.4-1: Residential Sector Confidence Intervals
Appendix: Figure 2.5-1: Farm Sector Confidence Intervals
Appendix: Figure 3.1-1: AIL Energy Confidence Intervals
Appendix: Figure 3.1-2: AIL Winter Peak Demand Confidence Intervals

Tables
Table 3.3-1: Energy Intensities
Table 4.0-1: Alberta Energy Sales to AIL Energy (GWh)
Table 4.1-1: AIL Winter Peak Demand
Table 4.1-2: AIL Summer Peak Demand
Table 4.1-3: AIL Annual Energy
Table 4.2-1: AIES Winter Peak Demand
Table 4.2-2: AIES Summer Peak Demand
Table 4.2-3: AIES Annual Energy
Table 4.3-1: DTS Annual Energy
Table 4.5-1: Coincident Peak Demand (MW) for South Region
Table 4.5-2: Coincident Peak Demand (MW) for Calgary Region
Table 4.5-3: Coincident Peak Demand (MW) for Central Region
Table 4.5-4: Coincident Peak Demand (MW) for Edmonton Region
Table 4.5-5: Coincident Peak Demand (MW) for Northeast Region
Table 4.5-6: Coincident Peak Demand (MW) for Northwest Region
Table 6.1-1: Energy Forecast Variance History
Table 6.1-2: Historical Energy with Adjustments for 10 Industrial Sites’ Reduction in Load
Table 6.1-3: Peak Forecast Variance History
Appendix: Table 3.1-1: AIL Energy Confidence Intervals
Appendix: Table 3.1-2: AIL Winter Peak Demand Confidence Intervals
Executive Summary

The Future Demand and Energy Outlook (2009 – 2029) (FC2009) is the Alberta Electric System Operator’s (AESO) long-term load forecast. The FC2009 describes the assumptions, methodology, and processes that the AESO uses to assess Alberta’s future demand and energy requirements.

This report is prepared annually in accordance with the duties of the AESO as outlined in Alberta’s Electric Utilities Act (EUA) and the Transmission Regulation (AR 86/2007) and will be used to support filings that may be submitted to the Alberta Utilities Commission (AUC).

The FC2009 includes a 20-year peak demand and electricity consumption forecast for Alberta. The load forecast is created from an economic growth forecast (gross domestic product or GDP), an oilsands production forecast, population projections and other variables, and by select customer sectors with regional adjustments based on historical results and customer-driven growth expectations.
In the past five years (2003 – 2008) Alberta internal load (AIL) peak demand has grown by an average of 206 megawatts (MW) (1.5 per cent) per year from 8,967 MW to 9,806 MW (an overall increase of 9.4 per cent). AIL is the sum of all electricity sales (residential, commercial, industrial and farm), losses (both transmission and distribution) and behind-the-fence load (BTF). Electricity consumption has grown by an average of 2.2 per cent per year from 62,716 gigawatt hours (GWh) to 69,947 GWh for the same period.

Historical energy growth in the last three years has been driven by oilsands projects and a booming oil and gas industry. However, over the past three years, the forestry, pulp and paper, and chemical industries have been negatively impacted by rising labour and other costs and lowered demand. As a result, a small number of industrial sites have either shut down or drastically reduced production, which has impacted overall energy and demand growth. The AESO has evaluated and researched the size and impact of these closures or reductions and determined that in the long term they are not material to the forecast. For this outlook, the AESO has not selected specific sites where shutdowns or reductions in load may occur in the future unless a specific customer request has been made.

The AESO forecasts AIL peak demand to grow by an average 3.3 per cent per year for the period from 2009 to 2029. Electricity consumption (energy) is also expected to grow by 3.2 per cent per year for the same period. The primary driver of this growth is related to growth in the oilsands and associated development.

The global financial meltdown of late 2008 and the subsequent worldwide economic recession have negatively affected economic growth in Alberta. However, it is expected that Alberta’s economy will recover and return to growth in 2010. Overall, long-run fundamentals remain robust with investments and developments in the oilsands expected to help drive strong economic growth over the next decade.

In addition to reporting the detailed forecast results, this report includes a summary of the AESO’s load forecasting methodology. The energy and demand forecast is prepared based on an examination of five sectors: industrial without oilsands, oilsands, commercial, residential and farm. The results are organized by the AESO’s five bulk transmission planning regions and six regional transmission planning regions.

The FC2009 concludes with a discussion of the challenges faced in preparing a load forecast for Alberta.
1.0 Introduction

The AESO’s long-term load forecast is a study of past energy use patterns and future economic indicators that are, in simple terms, combined to produce a future energy forecast. The AESO annually updates this forecast with a 20-year outlook of Alberta’s electric consumption and peak demand. The annual forecast is based on economic, demographic and customer information collected from January through June of 2009.

The AESO’s Future Demand and Energy Outlook (2009 – 2029) (FC2009), describes the assumptions, methodology and processes that the AESO employs to assess Alberta’s future demand and energy requirements.

The FC2009 recognizes future project uncertainty in regards to timing, size and number of large oilsands extraction facilities and upgraders in the northeast of the province. This uncertainty is reflected in the FC2009 demand and shows a drop in demand from AESO’s Future Demand and Energy Outlook (2008 – 2028) (FC2008) in the first 10-year period. In particular, the Northeast region shows a decrease of approximately 480 megawatts (MW) by 2018 from the FC2008. In general, the results of the FC2009 result in a delay of one year in AIL peak demand by 2018/19 and by two to three years by 2028/29. AESO transmission planning processes are purposefully flexible and staged to allow for slight fluctuations in the load forecast. The delay in peak demand lies within the confidence bands as outlined in Appendix A.
2.0 Economic Outlook

The foundation for the AESO’s electricity demand and energy forecast is Alberta’s economic outlook, which continues to be strong according to The Conference Board of Canada’s long-term economic forecast (Provincial Outlook Long-term Forecast 2009, published in April 2009). As well, estimates of investment and growth in the oilsands sector will continue to power Alberta’s economy in the next 15 years according to the Canadian Association of Petroleum Producers (CAPP) (Crude Oil Forecast, Markets & Pipeline Expansions - June 2009; Moderate Forecast).

The AESO’s economic outlook is developed by reviewing and using information and analysis from The Conference Board of Canada, CAPP and Statistics Canada.

The key factor driving the Alberta economy continues to be investment in the development of oilsands, which is largely driven by oil demand and world crude oil prices. This investment creates jobs and economic activity that, in general, will lead to a continuation of increases in annual electricity use.

2.1 ALBERTA’S GDP GROWTH

Gross domestic product (GDP), a measure of economic activity, is a function of consumer spending, private and public investment, and exports and imports. Declining crude oil and natural gas prices resulting from the world recession have negatively impacted the energy-dependent Alberta economy. Consequently, the province entered into a recession and experienced negative economic growth in 2009.

However, it is generally expected the Alberta economy will begin to rebound in 2010 followed by several years of strong growth. This strong growth is expected to be primarily driven by investments in the oilsands sector. Increasing world demand for crude oil, especially from emerging countries, combined with difficulty in increasing supply from traditional oil exporting regions is likely to increase demand for oilsands bitumen. Oilsands investment will spur additional economic activity in supporting industries and will generally benefit the province’s economy. In addition, job creation will encourage immigration to Alberta.

Economic growth, as measured by provincial GDP, is expected to be strong in the coming decade despite an expected economic contraction in 2009. GDP growth from 2010 to 2020 is expected to range from 2.1 to 5.5 per cent annually. According to The Conference Board of Canada’s Provincial Outlook Spring 2009, GDP is forecast to decline by 2.4 per cent in 2009 and increase by 2.9 per cent in 2010.
Long-run economic growth in Alberta will be somewhat tempered by labour constraints and increasing construction and materials costs, as well as increasing living costs and under-developed infrastructure.

As shown in Figure 2.1-1, declining crude oil prices negatively impacted the Alberta economy in 2008 and 2009. However, a rebound in crude oil prices and demand for crude oil is expected to create strong economic growth for several years. Thereafter, it is expected the economy will continue to grow at a more modest but stable rate as oilsands production continues to benefit the province economically. As a result, the long-run economic fundamentals for Alberta remain strong.

Figure 2.1-1: Changes in GDP

The overarching strength of the Alberta economy does not preclude the existence of economic difficulties in some sectors. In 2008, a number of chemical, forestry and pulp and paper mill facilities shut down. These shutdowns were caused by a combination of reduced demand due to the recession and other factors including: reduced demand for forestry products because of the U.S. housing market decline; reduced demand for pulp and paper; and reduced demand for sodium chlorate, which is used in pulp and paper manufacturing, as well as increasing costs as those industries competed with the oil and gas sector for labour and materials. While it is expected the Alberta economy will begin to recover and grow in 2010, it is possible not all industries will be affected in the same way.

In summary, over the next decade the energy sector will continue to be Alberta’s primary economic driver contributing to continued growth in electricity consumption. This assumption is based on future energy prices, a very significant non-conventional oil supply and extraction technology improvements. Over the 20-year forecast horizon, Alberta’s economy is expected to exhibit solid GDP growth, expanding at an average annual rate of 2.7 per cent.
2.2 ALBERTA’S POPULATION GROWTH

In 2008, Alberta’s population grew by approximately 70,000 people (two per cent) to 3.54 million. As depicted in Figure 2.2-1, the forecast for population growth is expected to remain steady at over one per cent year-over-year growth.

Figure 2.2-1: Population Growth in Alberta

Figure 2.2-2: Alberta Population
2.3 OILSANDS PRODUCTION GROWTH

Due to the strong dependency of the Alberta economy on oilsands activity, the AESO has a separate customer sector for the energy consumed by oilsands. The oilsands sector is located in the Cold Lake, Athabasca/Lac La Biche, Peace River and Fort McMurray transmission planning areas and includes in situ, mining and upgraded bitumen production. The energy consumed to produce a barrel of bitumen or synthetic crude oil from bitumen can be calculated. Therefore, electricity consumption by this sector can be forecast with assumptions of kilowatt hour/barrel (kWh/barrel) multiplied by an oilsands production forecast. The assumptions regarding oilsands energy intensity are further discussed in Section 3.3.

For the FC2009, the AESO used CAPP’s Crude Oil Forecast, Markets & Pipeline Expansions – June 2009 production forecast of ‘Oil Sands Mining’ and ‘In-Situ Moderate Growth’ and synthetic light crude oil to reflect upgraded bitumen production. Years 2026 through to 2029 were extrapolated using CAPP’s 2020-2025 growth rate. CAPP’s in situ and mined bitumen production forecasts are shown in Figure 2.3-1 and the synthetic crude oil production is shown in Figure 2.3-2. CAPP’s forecast production numbers are also analyzed to ensure they are consistent with The Conference Board of Canada’s non-conventional crude oil production forecasts, as well as with the AESO’s information regarding oilsands project timing. These forecasts are sufficiently consistent; therefore, CAPP’s production numbers are appropriate to use.
Figure 2.3-1: Oilsands Bitumen Production Forecast

Figure 2.3-2: Synthetic Crude Oil Production Forecast
3.0 Methodology

The AESO primarily uses an econometric approach to estimating future demand and electricity usage. This methodology provides a consistent approach to load forecasting through the use of a combination of fitted statistical models, historical data, third-party economic forecasts and customer-specific information.

The long-term load forecast is developed by considering the five categories listed below:

- Industrial without Oilsands
- Oilsands
- Commercial
- Residential
- Farm

A high-level overview of the AESO’s long-term load forecasting methodology is found in Figure 3.1-1 and details for each sector are discussed in the sections that follow.
3.1 AESO METHODOLOGY DIAGRAM

Figure 3.1-1: AESO Load Forecast Methodology Flow Diagram

```
Diagram Description:
- "Note: refers to Historical Energy"

**Industrial Customer Sector**
- Analysis

**Commercial Customer Sector**
- Analysis

**Residential Customer Sector**
- Analysis

**Farm Customer Sector**
- Analysis

**Historical Behind-the-Fence Energy**
- Analysis

**Economic and Other Assumptions**
- Analysis

**Forecast**
- Energy Growth by Customer Sector

**Forecast**
- Annual Peak Forecast (by MP_ID)

**Large Project Information**
- (by MP_ID)

**Distribution facility owner input**
- (by MP_ID)

**5-year historical growth rate**
- (by MP_ID)

**Forecast**
- Two year historical hourly loads
  - (for each MP_ID)

**Analysis**
- Typical Load Shape
  - (for each MP_ID)

**Adjustment**

**Comparison**

**Forecast Hourly Load Shapes**
- (by MP_ID)

**Aggregate**

**On-site Generation Forecast**

**ALL Forecast**
- Total Alberta Hourly Load

**AIES Forecast**
- Total Alberta Hourly Load

Note: MP_ID refers to metering points
```
3.2 INDUSTRIAL (WITHOUT OILSANDS) CUSTOMER SECTOR

The Industrial sector is the largest in terms of load and electricity consumption, comprising roughly 45 per cent of total AIL energy. The forecast for this sector is a function of expected real economic growth and historical usage.

Figure 3.2-1 shows industrial energy use in Alberta from 1967 to 2008. While historically there has been consistent growth in industrial energy, there has been a decline in the past three years resulting from the shut down of a number of chemical plants, forestry and pulp and paper operations.

In designing the economic models for the 2009 – 2029 customer sector forecast, the AESO looked at various economic indicators that should be used to best predict the future demand of this sector. In the AESO’s studies, the best fit was found between Alberta mining GDP and the energy sector. The mining sector, which includes oil and gas extraction, is the largest percentage of industrial energy sales (Figure 3.2-2). The Alberta mining category used by Statistics Canada measures the value of output of all industries engaged in extracting naturally occurring minerals. The term mining is used in the broad sense to include quarrying, well operations, milling and other preparation customarily done at site. This includes oil and gas exploration and development. A given unit of output from mining, oil and gas GDP requires a certain amount of related infrastructure such as pipelines, compressors, pumps, processing facilities and other equipment, which all require electricity. The manufacturing of steel, pipes, wellheads, pump jacks, compressors and other equipment is also needed for that infrastructure and also requires electricity. Mining, oil and gas GDP is the best measure of activity in oil and gas and its related industries. By using mining, oil and gas GDP to derive the industrial energy forecast, it is assumed that the amount of infrastructure and related electricity use remains constant. With the dependency of Alberta’s economy on the energy sector, it is intuitive that the industrial sector is highly dependent on the health of energy exploration and development.

Figure 3.2-1: Historical Industrial (without Oilsands) Energy

Source: AESO and ERCB
Regression analysis is used to determine the relationship of Alberta mining GDP to industrial (without oilsands) energy while controlling for other factors. Using this relationship and the Alberta mining GDP forecasts from The Conference Board of Canada, the AESO forecasts future industrial (without oilsands) energy growth. The results of this forecast are shown in Figures 3.2-3 and 3.2-4.
As seen in Figure 3.2-4, the AESO is forecasting growth in industrial (without oilsands) energy after three years of decline. This historical decline can be largely attributed to the exit and reduced activities of a limited number of industrial firms in the province. This decline is discussed further in Section 3.7.

### 3.3 OILSANDS CUSTOMER SECTOR

The oilsands sector is comprised of sites using mining and in situ extraction techniques to remove bitumen from the ground, as well as facilities that upgrade crude bitumen into synthetic crude oil. These sites make up approximately 13 per cent of total AIL energy. Each of these technologies uses different amounts of electricity to extract bitumen. Due to this, the AESO used an industry forecast of oilsands that includes a break out of these three extraction and upgrading technologies. No other large-scale extraction technologies are currently being utilized and, therefore, have not been incorporated into the forecast.

The AESO estimated the average kWh/barrel required for in situ, mining, and upgraded operations using actual historical usage and are shown below in Table 3.3-1.

<table>
<thead>
<tr>
<th>Operation Type</th>
<th>kWh/barrel</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mining</td>
<td>14.5</td>
</tr>
<tr>
<td>Upgrading</td>
<td>9.7</td>
</tr>
<tr>
<td>In situ</td>
<td>12.1</td>
</tr>
</tbody>
</table>

*Source: AESO*
The oilsands energy intensities are combined with the forecast of oilsands and upgrading production from CAPP’s June 2009 outlook to produce a forecast of oilsands electricity consumption.

**Figure 3.3-1: Oilsands Energy Intensity**

![Oilsands Energy Intensity Graph](image)

**Figure 3.3-2: Oilsands Energy Forecast**

![Oilsands Energy Forecast Graph](image)

Source: AESO and CAPP

Note: historical data for Mining and Upgrading is combined.
3.4 COMMERCIAL CUSTOMER SECTOR

The commercial sector is the second largest in terms of electricity consumption, accounting for roughly 19 per cent of total AIL energy. The forecast for this sector is a function of real economic growth and historical usage. Figure 3.4-1 shows historical commercial energy use in Alberta from 1967 to 2008.

The AESO’s commercial energy forecast relies on the historical relationship between Alberta’s economic activity and electricity energy (Figure 3.4-2), which are analyzed and, along with a forecast of Alberta’s future economic growth, used to determine future electricity energy growth in this sector.

Figure 3.4-1: Historical Commercial Energy Usage

![Historical Commercial Energy Usage Graph](image)

Source: AESO and ERCB

Figure 3.4-2: Commercial Energy and Alberta GDP

![Commercial Energy and Alberta GDP Graph](image)

Source: AESO, ERCB and The Conference Board of Canada
The FC2009 commercial energy forecast predicts a decline in commercial energy use in 2009. This is the result of expected declines in Alberta GDP in 2009. As Figure 3.4-2 shows, historically there has been strong correlation between commercial energy use and GDP. The Conference Board of Canada is predicting negative GDP growth in Alberta in 2009, followed by a modest recovery in 2010 and strong GDP growth thereafter. This is reflected in the commercial energy forecast.
3.5 RESIDENTIAL CUSTOMER SECTOR

The residential sector forecast is a function of population and disposable income per person, and is roughly 13 per cent of total AIL energy consumption. Figure 3.5-1 shows historical residential energy.

**Figure 3.5-1: Historical Residential Energy Use**

The AESO has assumed that residential energy use will change with population. Disposable income per person is also used as an input variable since it reflects residents’ ability to afford larger homes, which require more lighting, heating and cooling, electric appliances and electronics.
Residential energy use per person is shown in Figure 3.5-2. The historical trend of increasing usage per person is forecast to continue in the FC2009 residential energy forecast as seen in Figure 3.5-3.

**Figure 3.5-2: Residential Energy Use Per Capita**

![Figure 3.5-2: Residential Energy Use Per Capita](image)

Source: AESO, ERCB, Statistics Canada CANSIM and The Conference Board of Canada

**Figure 3.5-3: Residential Energy Forecast**

![Figure 3.5-3: Residential Energy Forecast](image)

Source: AESO
3.6 FARM CUSTOMER SECTOR

The farm sector is the smallest of all sectors analyzed by the AESO, and is roughly three per cent of total AIL energy. Farm energy is primarily used for irrigation purposes, and irrigation requirements depend on the amount of land used for agricultural purposes. Historical farm energy is shown in Figure 3.6-1.

**Figure 3.6-1: Historical Farm Energy**

Historical farm electricity consumption has not significantly changed since the mid 1990s and land used for agricultural purposes has not varied significantly (Figure 3.6-2). The AESO does not expect significant changes to farm energy use in its forecast. Therefore, the 10-year historical average annual energy use is used, which results in a slight decline in farm energy from 2008.
Figure 3.6-2: Agricultural Land in Alberta

![Agricultural Land in Alberta Chart]

Source: AESO and Statistics Canada

Figure 3.6-3: Farm Energy Forecast

![Farm Energy Forecast Chart]

Source: AESO and ERCB
3.7 HISTORICAL GROWTH AND DECREASE IN 10 INDUSTRIAL SITES

AIL energy use over the past five years grew at an annualized rate of 1.5 per cent. However, the AESO is forecasting energy growth to average 4.4 per cent annually over the period from 2009 to 2014 and 3.2 per cent over the period from 2009 to 2029. This difference in growth rates can be explained through a combination of factors.

Over the past five years, Alberta has been characterized by strong economic growth as a result of a booming oil and gas industry caused by high commodity prices. However, as the oil and gas industry boomed, other industries in the province did not. Specifically, the pulp and paper, forestry, and chemical industries suffered due to higher costs and lower demand. All three industries faced higher labour and materials costs. The rapidly growing oil and gas industry created low unemployment in Alberta, causing upward pressure on wages, especially for skilled workers. Demand by the oil and gas industry for materials such as steel and cement also increased, resulting in higher costs for all industries.

While costs rose, the pulp and paper, forestry, and chemical industries also faced decreased demand for their products. Demand for pulp and paper declined as a result of the decline of newsprint. Demand for Alberta forestry products has also declined since the U.S. housing market peaked in early 2006 and subsequently decreased. Demand for sodium chlorate, which is used to bleach pulp and paper, has also declined.

Figure 3.7-1 shows the combined electricity consumption of 10 industrial firms which operate or operated in Alberta in the forestry, pulp and paper, and chemical industries. These firms have either shut down or ramped down operations since 2005, resulting in decreased energy use. Analysis indicates they had decreased energy use by 2,375 GWh per year in 2008 compared to 2005 levels. This adjustment factor of 2,375 GWh could have increased AIL energy in 2008 by 3.4 per cent (see Table 6.1-2). Assuming this decrease of 2,375 GWh had not occurred between 2005 and 2008 by these 10 industrial firms, AIL energy would have had a five-year average annual growth rate of 2.9 per cent instead of 2.2 per cent.

It is not possible to predict how or when a given firm may choose to shut down or ramp down operations. However, a recent rebound in pulp and paper prices and a recovering U.S. housing market, combined with an expected overall economic recovery, suggest it is less likely companies will shut down or ramp down operations in the foreseeable future. In addition, the small portion of pulp and paper, forestry, and chemical companies as a fraction of industrial energy use suggests there is minimal potential additional loss from further shut down or ramp down of these industries.
Strong energy growth rates forecast by the AESO are reasonable in the context of historical growth rates. Figure 3.7-3 shows the AIL historical and forecast energy growth rates. The 10-firm energy adjustment factor is also shown for comparison. The historical annual compounded growth rate with the 10-firm adjustment from 1995 to 2008 is 3.5 per cent compared with 3.2 per cent forecast from 2009 to 2029.
The AESO’s AIL forecast utilizes The Conference Board of Canada estimates of GDP and population. The Conference Board forecasts strong economic growth (Figure 3.7-4) being driven by investment and development in the oilsands. This strong growth and development is expected to translate into strong energy growth as oilsands operations ramp up and as supporting industries and growing population contribute to increased electricity use.

**Figure 3.7-3: Historical and Forecast AIL Energy Growth**

![Historical and Forecast AIL Energy Growth chart]

**Figure 3.7-4: Alberta GDP Growth Forecasts**

![Alberta GDP Growth Forecasts chart]
4.0 Forecast Results

This section provides detailed forecast results for the period from 2009 to 2029 for the Alberta internal load (AIL), Alberta Interconnected Electric System (AIES) and demand tariff service (DTS) energy.

Table 4.0-1: Alberta Energy Sales to AIL Energy (GWh)

<table>
<thead>
<tr>
<th>Year</th>
<th>Industrial without Oilsands (GWh)</th>
<th>Oilsands (GWh)</th>
<th>Commercial (GWh)</th>
<th>Residential (GWh)</th>
<th>Farm (GWh)</th>
<th>Sector Total ¹ (GWh)</th>
<th>Losses ² (GWh)</th>
<th>Other ³ (GWh)</th>
<th>AIL (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2003</td>
<td>31,064</td>
<td>5,938</td>
<td>11,100</td>
<td>7,560</td>
<td>1,775</td>
<td>57,436</td>
<td>5,111</td>
<td>170</td>
<td>62,716</td>
</tr>
<tr>
<td>2004</td>
<td>32,574</td>
<td>6,485</td>
<td>11,672</td>
<td>7,559</td>
<td>1,733</td>
<td>60,024</td>
<td>5,060</td>
<td>175</td>
<td>65,259</td>
</tr>
<tr>
<td>2005</td>
<td>32,982</td>
<td>6,695</td>
<td>12,081</td>
<td>7,769</td>
<td>1,705</td>
<td>61,232</td>
<td>4,860</td>
<td>176</td>
<td>66,288</td>
</tr>
<tr>
<td>2006</td>
<td>32,970</td>
<td>8,337</td>
<td>12,733</td>
<td>8,254</td>
<td>1,769</td>
<td>64,063</td>
<td>5,129</td>
<td>178</td>
<td>69,371</td>
</tr>
<tr>
<td>2007</td>
<td>31,922</td>
<td>8,529</td>
<td>13,114</td>
<td>8,539</td>
<td>1,806</td>
<td>63,909</td>
<td>5,584</td>
<td>167</td>
<td>69,660</td>
</tr>
<tr>
<td>2008</td>
<td>31,088</td>
<td>9,330</td>
<td>13,526</td>
<td>8,833</td>
<td>1,803</td>
<td>64,580</td>
<td>5,150</td>
<td>217</td>
<td>69,947</td>
</tr>
<tr>
<td>2009</td>
<td>31,025</td>
<td>9,945</td>
<td>13,146</td>
<td>9,811</td>
<td>1,756</td>
<td>64,853</td>
<td>5,085</td>
<td>246</td>
<td>70,184</td>
</tr>
<tr>
<td>2010</td>
<td>31,480</td>
<td>11,088</td>
<td>13,386</td>
<td>9,151</td>
<td>1,756</td>
<td>66,862</td>
<td>5,283</td>
<td>315</td>
<td>72,499</td>
</tr>
<tr>
<td>2011</td>
<td>32,581</td>
<td>11,932</td>
<td>14,026</td>
<td>9,369</td>
<td>1,756</td>
<td>69,664</td>
<td>5,288</td>
<td>359</td>
<td>75,312</td>
</tr>
<tr>
<td>2012</td>
<td>34,384</td>
<td>12,455</td>
<td>14,828</td>
<td>9,594</td>
<td>1,756</td>
<td>73,017</td>
<td>5,457</td>
<td>490</td>
<td>78,963</td>
</tr>
<tr>
<td>2013</td>
<td>36,741</td>
<td>13,159</td>
<td>15,548</td>
<td>9,808</td>
<td>1,756</td>
<td>77,013</td>
<td>5,319</td>
<td>545</td>
<td>82,877</td>
</tr>
<tr>
<td>2014</td>
<td>38,717</td>
<td>14,218</td>
<td>16,021</td>
<td>10,003</td>
<td>1,756</td>
<td>80,715</td>
<td>5,583</td>
<td>667</td>
<td>86,965</td>
</tr>
<tr>
<td>2015</td>
<td>40,841</td>
<td>15,103</td>
<td>16,465</td>
<td>10,204</td>
<td>1,756</td>
<td>84,368</td>
<td>5,816</td>
<td>716</td>
<td>90,090</td>
</tr>
<tr>
<td>2016</td>
<td>43,191</td>
<td>16,166</td>
<td>16,965</td>
<td>10,408</td>
<td>1,756</td>
<td>88,486</td>
<td>6,084</td>
<td>764</td>
<td>95,535</td>
</tr>
<tr>
<td>2017</td>
<td>45,128</td>
<td>16,892</td>
<td>17,403</td>
<td>10,606</td>
<td>1,756</td>
<td>91,786</td>
<td>6,282</td>
<td>802</td>
<td>98,780</td>
</tr>
<tr>
<td>2018</td>
<td>46,844</td>
<td>17,814</td>
<td>17,868</td>
<td>10,812</td>
<td>1,756</td>
<td>94,894</td>
<td>6,497</td>
<td>830</td>
<td>102,220</td>
</tr>
<tr>
<td>2019</td>
<td>48,217</td>
<td>18,487</td>
<td>18,288</td>
<td>11,016</td>
<td>1,756</td>
<td>97,765</td>
<td>6,701</td>
<td>878</td>
<td>105,344</td>
</tr>
<tr>
<td>2020</td>
<td>49,572</td>
<td>19,515</td>
<td>18,741</td>
<td>11,229</td>
<td>1,756</td>
<td>100,813</td>
<td>6,904</td>
<td>921</td>
<td>108,638</td>
</tr>
<tr>
<td>2021</td>
<td>50,880</td>
<td>19,940</td>
<td>19,202</td>
<td>11,447</td>
<td>1,756</td>
<td>103,225</td>
<td>7,064</td>
<td>919</td>
<td>111,208</td>
</tr>
<tr>
<td>2022</td>
<td>52,153</td>
<td>20,524</td>
<td>19,672</td>
<td>11,669</td>
<td>1,756</td>
<td>105,775</td>
<td>7,229</td>
<td>919</td>
<td>113,923</td>
</tr>
<tr>
<td>2023</td>
<td>53,393</td>
<td>21,164</td>
<td>20,160</td>
<td>11,896</td>
<td>1,756</td>
<td>108,368</td>
<td>7,401</td>
<td>922</td>
<td>116,691</td>
</tr>
<tr>
<td>2024</td>
<td>54,662</td>
<td>21,568</td>
<td>20,652</td>
<td>12,126</td>
<td>1,756</td>
<td>110,765</td>
<td>7,571</td>
<td>925</td>
<td>119,261</td>
</tr>
<tr>
<td>2025</td>
<td>55,950</td>
<td>21,765</td>
<td>21,149</td>
<td>12,359</td>
<td>1,756</td>
<td>112,980</td>
<td>7,737</td>
<td>924</td>
<td>121,640</td>
</tr>
<tr>
<td>2026</td>
<td>57,281</td>
<td>22,249</td>
<td>21,652</td>
<td>12,590</td>
<td>1,756</td>
<td>115,527</td>
<td>7,906</td>
<td>922</td>
<td>124,355</td>
</tr>
<tr>
<td>2027</td>
<td>58,605</td>
<td>22,743</td>
<td>22,164</td>
<td>12,826</td>
<td>1,756</td>
<td>118,094</td>
<td>8,080</td>
<td>922</td>
<td>127,096</td>
</tr>
<tr>
<td>2028</td>
<td>59,967</td>
<td>23,249</td>
<td>22,696</td>
<td>13,064</td>
<td>1,756</td>
<td>120,732</td>
<td>8,255</td>
<td>925</td>
<td>129,911</td>
</tr>
<tr>
<td>2029</td>
<td>61,326</td>
<td>23,767</td>
<td>23,234</td>
<td>13,310</td>
<td>1,756</td>
<td>123,393</td>
<td>8,430</td>
<td>923</td>
<td>132,746</td>
</tr>
</tbody>
</table>

Note: figures in colour denote actuals
¹ Numbers may not add up due to rounding
² Includes transmission and distribution losses
³ Other includes Fort Nelson (supplied by AIES)
**4.1 PROVINCIAL RESULTS – AIL FORECAST**

AIL is the sum of all electricity sales (residential, commercial, industrial and farm), losses (both transmission and distribution) and behind-the-fence load (BTF). BTF is any industrial load that is characterized by being served in whole, or in part, by on-site generation.

Tables 4.1-1 through 4.1-3 compare the growth in AIL demand and energy from the FC2009 with last year’s forecast, the FC2008. In the last five years, AIL demand has grown by 1.5 per cent per year and AIL energy has grown by 2.2 per cent per year. For the next five years, average annual demand is forecast to grow by 4.4 per cent and energy is expected to grow by 4.4 per cent. The FC2009 shows an annual average growth rate of 3.3 per cent for AIL load and a growth rate for energy of 3.2 per cent for the period 2009 to 2029.

<table>
<thead>
<tr>
<th>Year</th>
<th>FC2008 (MW)</th>
<th>FC2009 (MW)</th>
<th>FC2009 Growth (%)</th>
<th>Forecast Differential (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2003/04</td>
<td>8,786</td>
<td></td>
<td>2.5</td>
<td></td>
</tr>
<tr>
<td>2004/05</td>
<td>9,236</td>
<td></td>
<td>5.1</td>
<td></td>
</tr>
<tr>
<td>2005/06</td>
<td>9,580</td>
<td></td>
<td>3.7</td>
<td></td>
</tr>
<tr>
<td>2006/07</td>
<td>9,661</td>
<td></td>
<td>0.8</td>
<td></td>
</tr>
<tr>
<td>2007/08</td>
<td>9,710</td>
<td></td>
<td>0.5</td>
<td></td>
</tr>
<tr>
<td>2008/09</td>
<td>9,806</td>
<td></td>
<td>1.0</td>
<td></td>
</tr>
<tr>
<td>2009/10</td>
<td>9,846</td>
<td></td>
<td>0.4</td>
<td>-356</td>
</tr>
<tr>
<td>2010/11</td>
<td>10,170</td>
<td></td>
<td>3.3</td>
<td>-480</td>
</tr>
<tr>
<td>2011/12</td>
<td>10,577</td>
<td></td>
<td>4.0</td>
<td>-640</td>
</tr>
<tr>
<td>2012/13</td>
<td>11,076</td>
<td></td>
<td>4.7</td>
<td>-661</td>
</tr>
<tr>
<td>2013/14</td>
<td>11,664</td>
<td></td>
<td>5.3</td>
<td>-693</td>
</tr>
<tr>
<td>2014/15</td>
<td>12,162</td>
<td></td>
<td>4.3</td>
<td>-735</td>
</tr>
<tr>
<td>2015/16</td>
<td>12,801</td>
<td></td>
<td>5.3</td>
<td>-600</td>
</tr>
<tr>
<td>2016/17</td>
<td>13,382</td>
<td></td>
<td>4.5</td>
<td>-517</td>
</tr>
<tr>
<td>2017/18</td>
<td>13,856</td>
<td></td>
<td>3.5</td>
<td>-434</td>
</tr>
<tr>
<td>2018/19</td>
<td>14,351</td>
<td></td>
<td>3.6</td>
<td>-308</td>
</tr>
<tr>
<td>2019/20</td>
<td>14,759</td>
<td></td>
<td>2.8</td>
<td>-358</td>
</tr>
<tr>
<td>2020/21</td>
<td>15,162</td>
<td></td>
<td>2.7</td>
<td>-411</td>
</tr>
<tr>
<td>2021/22</td>
<td>15,618</td>
<td></td>
<td>3.0</td>
<td>-369</td>
</tr>
<tr>
<td>2022/23</td>
<td>15,994</td>
<td></td>
<td>2.4</td>
<td>-437</td>
</tr>
<tr>
<td>2023/24</td>
<td>16,369</td>
<td></td>
<td>2.3</td>
<td>-491</td>
</tr>
<tr>
<td>2024/25</td>
<td>16,725</td>
<td></td>
<td>2.2</td>
<td>-587</td>
</tr>
<tr>
<td>2025/26</td>
<td>17,114</td>
<td></td>
<td>2.3</td>
<td>-684</td>
</tr>
<tr>
<td>2026/27</td>
<td>17,505</td>
<td></td>
<td>2.3</td>
<td>-793</td>
</tr>
<tr>
<td>2027/28</td>
<td>17,855</td>
<td></td>
<td>2.0</td>
<td>-926</td>
</tr>
<tr>
<td>2028/29</td>
<td>18,196</td>
<td></td>
<td>1.9</td>
<td>-1,075</td>
</tr>
<tr>
<td>2029/30</td>
<td>18,695</td>
<td></td>
<td>2.7</td>
<td>-1,115</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year</th>
<th>FC2008 (MW)</th>
<th>FC2009 (MW)</th>
<th>FC2009 Growth (%)</th>
<th>Forecast Differential (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2003</td>
<td>8,295</td>
<td></td>
<td>0.9</td>
<td></td>
</tr>
<tr>
<td>2004</td>
<td>8,578</td>
<td></td>
<td>3.4</td>
<td></td>
</tr>
<tr>
<td>2005</td>
<td>8,566</td>
<td></td>
<td>0.1</td>
<td></td>
</tr>
<tr>
<td>2006</td>
<td>9,050</td>
<td></td>
<td>5.7</td>
<td></td>
</tr>
<tr>
<td>2007</td>
<td>9,321</td>
<td></td>
<td>3.0</td>
<td></td>
</tr>
<tr>
<td>2008</td>
<td>9,541</td>
<td></td>
<td>2.4</td>
<td></td>
</tr>
<tr>
<td>2009</td>
<td>9,685</td>
<td></td>
<td>0.6</td>
<td>-201</td>
</tr>
<tr>
<td>2010</td>
<td>10,037</td>
<td></td>
<td>1.1</td>
<td>-448</td>
</tr>
<tr>
<td>2011</td>
<td>10,487</td>
<td></td>
<td>3.4</td>
<td>-575</td>
</tr>
<tr>
<td>2012</td>
<td>10,976</td>
<td></td>
<td>5.0</td>
<td>-568</td>
</tr>
<tr>
<td>2013</td>
<td>11,559</td>
<td></td>
<td>5.1</td>
<td>-618</td>
</tr>
<tr>
<td>2014</td>
<td>12,112</td>
<td></td>
<td>5.6</td>
<td>-564</td>
</tr>
<tr>
<td>2015</td>
<td>12,651</td>
<td></td>
<td>4.6</td>
<td>-574</td>
</tr>
<tr>
<td>2016</td>
<td>12,642</td>
<td></td>
<td>4.7</td>
<td>-469</td>
</tr>
<tr>
<td>2017</td>
<td>13,554</td>
<td></td>
<td>4.0</td>
<td>-408</td>
</tr>
<tr>
<td>2018</td>
<td>13,927</td>
<td></td>
<td>3.2</td>
<td>-367</td>
</tr>
<tr>
<td>2019</td>
<td>14,293</td>
<td></td>
<td>3.0</td>
<td>-319</td>
</tr>
<tr>
<td>2020</td>
<td>14,374</td>
<td></td>
<td>2.9</td>
<td>-411</td>
</tr>
<tr>
<td>2021</td>
<td>14,765</td>
<td></td>
<td>2.7</td>
<td>-432</td>
</tr>
<tr>
<td>2022</td>
<td>15,131</td>
<td></td>
<td>2.5</td>
<td>-494</td>
</tr>
<tr>
<td>2023</td>
<td>15,500</td>
<td></td>
<td>2.4</td>
<td>-539</td>
</tr>
<tr>
<td>2024</td>
<td>15,791</td>
<td></td>
<td>1.9</td>
<td>-657</td>
</tr>
<tr>
<td>2025</td>
<td>16,157</td>
<td></td>
<td>2.3</td>
<td>-748</td>
</tr>
<tr>
<td>2026</td>
<td>16,531</td>
<td></td>
<td>2.3</td>
<td>-835</td>
</tr>
<tr>
<td>2027</td>
<td>16,904</td>
<td></td>
<td>2.3</td>
<td>-908</td>
</tr>
<tr>
<td>2028</td>
<td>17,237</td>
<td></td>
<td>2.0</td>
<td>-1,025</td>
</tr>
<tr>
<td>2029</td>
<td>17,656</td>
<td></td>
<td>2.4</td>
<td>-1,093</td>
</tr>
</tbody>
</table>

Note: figures in colour denote actuals

Note: 2002 includes a redefinition of BTF load and an addition of approximately 400 MW
### Table 4.1-3: AIL Annual Energy

<table>
<thead>
<tr>
<th>Year</th>
<th>FC2008 (GWh)</th>
<th>FC2009 (GWh)</th>
<th>FC2009 Growth (%)</th>
<th>Forecast Differential (GWh)</th>
<th>Load Factor (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2003</td>
<td>–</td>
<td>62,716</td>
<td>5.5</td>
<td>–</td>
<td>79.8</td>
</tr>
<tr>
<td>2004</td>
<td>–</td>
<td>65,259</td>
<td>4.1</td>
<td>–</td>
<td>82.9</td>
</tr>
<tr>
<td>2005</td>
<td>–</td>
<td>66,268</td>
<td>1.5</td>
<td>–</td>
<td>81.9</td>
</tr>
<tr>
<td>2006</td>
<td>–</td>
<td>69,371</td>
<td>4.7</td>
<td>–</td>
<td>82.7</td>
</tr>
<tr>
<td>2007</td>
<td>–</td>
<td>69,660</td>
<td>0.4</td>
<td>–</td>
<td>82.3</td>
</tr>
<tr>
<td>2008</td>
<td>–</td>
<td>69,947</td>
<td>0.4</td>
<td>–</td>
<td>82.2</td>
</tr>
<tr>
<td>2009</td>
<td>73,062</td>
<td>70,184</td>
<td>0.3</td>
<td>-2,878</td>
<td>81.7</td>
</tr>
<tr>
<td>2010</td>
<td>75,727</td>
<td>72,459</td>
<td>3.2</td>
<td>-3,268</td>
<td>84.0</td>
</tr>
<tr>
<td>2011</td>
<td>79,146</td>
<td>75,312</td>
<td>3.9</td>
<td>-3,834</td>
<td>84.5</td>
</tr>
<tr>
<td>2012</td>
<td>83,485</td>
<td>78,963</td>
<td>4.8</td>
<td>-4,522</td>
<td>85.0</td>
</tr>
<tr>
<td>2013</td>
<td>87,678</td>
<td>82,877</td>
<td>5.0</td>
<td>-4,801</td>
<td>85.4</td>
</tr>
<tr>
<td>2014</td>
<td>92,106</td>
<td>86,965</td>
<td>4.9</td>
<td>-5,141</td>
<td>85.1</td>
</tr>
<tr>
<td>2015</td>
<td>96,448</td>
<td>90,900</td>
<td>4.5</td>
<td>-5,548</td>
<td>85.3</td>
</tr>
<tr>
<td>2016</td>
<td>100,487</td>
<td>95,335</td>
<td>4.9</td>
<td>-5,152</td>
<td>84.8</td>
</tr>
<tr>
<td>2017</td>
<td>103,841</td>
<td>98,870</td>
<td>3.7</td>
<td>-4,971</td>
<td>84.3</td>
</tr>
<tr>
<td>2018</td>
<td>106,775</td>
<td>102,220</td>
<td>3.4</td>
<td>-4,555</td>
<td>84.2</td>
</tr>
<tr>
<td>2019</td>
<td>109,562</td>
<td>105,344</td>
<td>3.1</td>
<td>-4,218</td>
<td>83.8</td>
</tr>
<tr>
<td>2020</td>
<td>113,652</td>
<td>108,638</td>
<td>3.1</td>
<td>-5,014</td>
<td>83.8</td>
</tr>
<tr>
<td>2021</td>
<td>116,626</td>
<td>111,208</td>
<td>2.4</td>
<td>-5,418</td>
<td>83.7</td>
</tr>
<tr>
<td>2022</td>
<td>119,804</td>
<td>113,923</td>
<td>2.4</td>
<td>-5,881</td>
<td>83.3</td>
</tr>
<tr>
<td>2023</td>
<td>123,028</td>
<td>116,691</td>
<td>2.4</td>
<td>-6,337</td>
<td>83.3</td>
</tr>
<tr>
<td>2024</td>
<td>126,376</td>
<td>119,261</td>
<td>2.2</td>
<td>-7,115</td>
<td>82.9</td>
</tr>
<tr>
<td>2025</td>
<td>129,601</td>
<td>121,640</td>
<td>2.0</td>
<td>-7,961</td>
<td>83.0</td>
</tr>
<tr>
<td>2026</td>
<td>133,049</td>
<td>124,355</td>
<td>2.2</td>
<td>-8,694</td>
<td>82.9</td>
</tr>
<tr>
<td>2027</td>
<td>136,584</td>
<td>127,096</td>
<td>2.2</td>
<td>-9,488</td>
<td>82.9</td>
</tr>
<tr>
<td>2028</td>
<td>140,265</td>
<td>129,911</td>
<td>2.2</td>
<td>-10,354</td>
<td>82.8</td>
</tr>
<tr>
<td>2029</td>
<td>143,760</td>
<td>132,746</td>
<td>2.2</td>
<td>-11,014</td>
<td>83.3</td>
</tr>
</tbody>
</table>

Note: figures in colour denote actuals

Note: 2002 includes a redefinition of BTF load and an addition of approximately 400 MW
4.2 PROVINCIAL RESULTS – AIES FORECAST WITH BEHIND-THE-FENCE (BTF) LOAD ESTIMATION

The AESO forecasts the changes in the amount of on-site generation. To calculate AIES demand and energy, the AESO forecasts the amount of AIL served based on historical on-site generation plus any additions or deletions of on-site generation consistent with the AESO’s interconnection queue as of September 19, 2009. The results from this work are presented in the following three tables.

<table>
<thead>
<tr>
<th>Table 4.2-1: AIES Winter Peak Demand</th>
<th>Table 4.2-2: AIES Summer Peak Demand</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>FC2008 (MW)</td>
</tr>
<tr>
<td>2003/04</td>
<td>–</td>
</tr>
<tr>
<td>2004/05</td>
<td>–</td>
</tr>
<tr>
<td>2005/06</td>
<td>–</td>
</tr>
<tr>
<td>2006/07</td>
<td>–</td>
</tr>
<tr>
<td>2007/08</td>
<td>–</td>
</tr>
<tr>
<td>2008/09</td>
<td>–</td>
</tr>
<tr>
<td>2009/10</td>
<td>8,650</td>
</tr>
<tr>
<td>2010/11</td>
<td>8,994</td>
</tr>
<tr>
<td>2011/12</td>
<td>9,498</td>
</tr>
<tr>
<td>2012/13</td>
<td>9,943</td>
</tr>
<tr>
<td>2013/14</td>
<td>10,436</td>
</tr>
<tr>
<td>2014/15</td>
<td>10,866</td>
</tr>
<tr>
<td>2015/16</td>
<td>11,329</td>
</tr>
<tr>
<td>2016/17</td>
<td>11,780</td>
</tr>
<tr>
<td>2017/18</td>
<td>12,140</td>
</tr>
<tr>
<td>2018/19</td>
<td>12,493</td>
</tr>
<tr>
<td>2019/20</td>
<td>12,828</td>
</tr>
<tr>
<td>2020/21</td>
<td>13,213</td>
</tr>
<tr>
<td>2021/22</td>
<td>13,640</td>
</tr>
<tr>
<td>2022/23</td>
<td>14,095</td>
</tr>
<tr>
<td>2023/24</td>
<td>14,540</td>
</tr>
<tr>
<td>2024/25</td>
<td>14,981</td>
</tr>
<tr>
<td>2025/26</td>
<td>15,478</td>
</tr>
<tr>
<td>2026/27</td>
<td>15,977</td>
</tr>
<tr>
<td>2027/28</td>
<td>16,461</td>
</tr>
<tr>
<td>2028/29</td>
<td>16,951</td>
</tr>
<tr>
<td>2029/30</td>
<td>–</td>
</tr>
</tbody>
</table>

Note: figures in colour denote actuals
Table 4.2-3: AIES Annual Energy

<table>
<thead>
<tr>
<th>Year</th>
<th>FC2008 (GWh)</th>
<th>FC2009 (GWh)</th>
<th>FC2009 Growth (%)</th>
<th>Forecast Differential (GWh)</th>
<th>Load Factor (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2003</td>
<td>–</td>
<td>53,169</td>
<td>-0.9</td>
<td>–</td>
<td>79.3</td>
</tr>
<tr>
<td>2004</td>
<td>–</td>
<td>54,669</td>
<td>2.8</td>
<td>–</td>
<td>78.7</td>
</tr>
<tr>
<td>2005</td>
<td>–</td>
<td>55,697</td>
<td>1.9</td>
<td>–</td>
<td>78.8</td>
</tr>
<tr>
<td>2006</td>
<td>–</td>
<td>57,433</td>
<td>3.1</td>
<td>–</td>
<td>80.2</td>
</tr>
<tr>
<td>2007</td>
<td>–</td>
<td>57,701</td>
<td>0.5</td>
<td>–</td>
<td>80.0</td>
</tr>
<tr>
<td>2008</td>
<td>–</td>
<td>57,934</td>
<td>0.4</td>
<td>–</td>
<td>80.5</td>
</tr>
<tr>
<td>2009</td>
<td>60,105</td>
<td>58,115</td>
<td>0.3</td>
<td>-1,990</td>
<td>79.8</td>
</tr>
<tr>
<td>2010</td>
<td>62,364</td>
<td>59,430</td>
<td>2.3</td>
<td>-2,934</td>
<td>79.8</td>
</tr>
<tr>
<td>2011</td>
<td>65,368</td>
<td>61,716</td>
<td>3.8</td>
<td>-3,652</td>
<td>78.0</td>
</tr>
<tr>
<td>2012</td>
<td>69,139</td>
<td>65,132</td>
<td>5.5</td>
<td>-4,007</td>
<td>77.7</td>
</tr>
<tr>
<td>2013</td>
<td>72,648</td>
<td>68,792</td>
<td>5.6</td>
<td>-3,856</td>
<td>77.5</td>
</tr>
<tr>
<td>2014</td>
<td>76,020</td>
<td>72,512</td>
<td>5.4</td>
<td>-3,508</td>
<td>79.7</td>
</tr>
<tr>
<td>2015</td>
<td>79,833</td>
<td>75,984</td>
<td>4.8</td>
<td>-3,849</td>
<td>79.0</td>
</tr>
<tr>
<td>2016</td>
<td>83,521</td>
<td>79,927</td>
<td>5.2</td>
<td>-3,594</td>
<td>78.2</td>
</tr>
<tr>
<td>2017</td>
<td>86,293</td>
<td>83,163</td>
<td>4.0</td>
<td>-3,130</td>
<td>78.4</td>
</tr>
<tr>
<td>2018</td>
<td>88,531</td>
<td>86,334</td>
<td>3.8</td>
<td>-2,197</td>
<td>78.0</td>
</tr>
<tr>
<td>2019</td>
<td>90,809</td>
<td>89,232</td>
<td>3.4</td>
<td>-1,577</td>
<td>79.2</td>
</tr>
<tr>
<td>2020</td>
<td>93,794</td>
<td>92,269</td>
<td>3.4</td>
<td>-1,525</td>
<td>79.6</td>
</tr>
<tr>
<td>2021</td>
<td>96,722</td>
<td>94,812</td>
<td>2.8</td>
<td>-1,910</td>
<td>79.4</td>
</tr>
<tr>
<td>2022</td>
<td>99,830</td>
<td>97,381</td>
<td>2.7</td>
<td>-2,449</td>
<td>78.7</td>
</tr>
<tr>
<td>2023</td>
<td>103,009</td>
<td>99,887</td>
<td>2.6</td>
<td>-3,122</td>
<td>78.3</td>
</tr>
<tr>
<td>2024</td>
<td>106,226</td>
<td>102,329</td>
<td>2.4</td>
<td>-3,897</td>
<td>79.3</td>
</tr>
<tr>
<td>2025</td>
<td>109,462</td>
<td>104,716</td>
<td>2.3</td>
<td>-4,746</td>
<td>79.3</td>
</tr>
<tr>
<td>2026</td>
<td>112,916</td>
<td>107,368</td>
<td>2.5</td>
<td>-5,548</td>
<td>79.3</td>
</tr>
<tr>
<td>2027</td>
<td>116,447</td>
<td>110,090</td>
<td>2.5</td>
<td>-6,357</td>
<td>79.5</td>
</tr>
<tr>
<td>2028</td>
<td>120,051</td>
<td>112,853</td>
<td>2.5</td>
<td>-7,198</td>
<td>78.8</td>
</tr>
<tr>
<td>2029</td>
<td>–</td>
<td>115,715</td>
<td>2.5</td>
<td>–</td>
<td>78.6</td>
</tr>
</tbody>
</table>

Note: figures in colour denote actuals
4.3 PROVINCIAL RESULTS – DEMAND TARIFF SERVICE (DTS) ENERGY

The AESO forecasts the annual energy amounts served to DTS customers. This value is AIES minus transmission losses and Fort Nelson demand transmission service (FTS). The annual amounts from 2010 and beyond are shown in Table 4.3-1 below.

Table 4.3-1: DTS Annual Energy

<table>
<thead>
<tr>
<th>Year</th>
<th>FC2009 (GWh)</th>
<th>FC2009 Growth (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>55,866</td>
<td>–</td>
</tr>
<tr>
<td>2011</td>
<td>58,177</td>
<td>4.1</td>
</tr>
<tr>
<td>2012</td>
<td>61,089</td>
<td>5.0</td>
</tr>
<tr>
<td>2013</td>
<td>64,875</td>
<td>6.2</td>
</tr>
<tr>
<td>2014</td>
<td>67,791</td>
<td>4.5</td>
</tr>
<tr>
<td>2015</td>
<td>70,369</td>
<td>3.8</td>
</tr>
<tr>
<td>2016</td>
<td>73,990</td>
<td>5.1</td>
</tr>
<tr>
<td>2017</td>
<td>77,054</td>
<td>4.1</td>
</tr>
<tr>
<td>2018</td>
<td>80,071</td>
<td>3.9</td>
</tr>
<tr>
<td>2019</td>
<td>82,815</td>
<td>3.4</td>
</tr>
<tr>
<td>2020</td>
<td>85,581</td>
<td>3.3</td>
</tr>
<tr>
<td>2021</td>
<td>87,567</td>
<td>2.3</td>
</tr>
<tr>
<td>2022</td>
<td>89,689</td>
<td>2.4</td>
</tr>
<tr>
<td>2023</td>
<td>91,996</td>
<td>2.6</td>
</tr>
<tr>
<td>2024</td>
<td>94,228</td>
<td>2.4</td>
</tr>
<tr>
<td>2025</td>
<td>96,574</td>
<td>2.5</td>
</tr>
<tr>
<td>2026</td>
<td>99,151</td>
<td>2.7</td>
</tr>
<tr>
<td>2027</td>
<td>101,789</td>
<td>2.7</td>
</tr>
<tr>
<td>2028</td>
<td>104,471</td>
<td>2.6</td>
</tr>
<tr>
<td>2029</td>
<td>107,259</td>
<td>2.7</td>
</tr>
</tbody>
</table>

4.4 FORECAST RESULTS FOR BULK PLANNING PURPOSES

From a bulk transmission planning perspective, the AESO has defined five primary regions in Alberta. There are also two large urban centres: Calgary and Edmonton.

Figure 4.4-1 shows the forecast regional winter peaks for 2009, 2019 and 2029 and Figure 4.4-2 shows the regional summer peaks for the same periods. In this case, the winter season is the period from November 1 to April 30 and the summer season is from May 1 to October 31.

Strong growth in the Northeast, Calgary, and South Central regions is driven mainly by oilsands and upgrading production forecasts for the northeast, and by increasing pipeline demand from Hardisty south into the U.S. in the Calgary and South Central regions.
Figure 4.4-1: Region Demand at Time of Winter All Peak Demand

<table>
<thead>
<tr>
<th>Region</th>
<th>2009</th>
<th>2019</th>
<th>2029</th>
</tr>
</thead>
<tbody>
<tr>
<td>Northwest</td>
<td>1,058</td>
<td>1,498</td>
<td>1,852</td>
</tr>
<tr>
<td>Northeast</td>
<td>2,063</td>
<td>4,035</td>
<td>5,140</td>
</tr>
<tr>
<td>Edmonton &amp; North Central</td>
<td>2,147</td>
<td>2,916</td>
<td>3,630</td>
</tr>
<tr>
<td>Calgary &amp; South Central</td>
<td>3,354</td>
<td>4,741</td>
<td>6,136</td>
</tr>
<tr>
<td>Edmonton Only</td>
<td>1,151</td>
<td>1,543</td>
<td>1,891</td>
</tr>
<tr>
<td>Calgary Only</td>
<td>1,450</td>
<td>1,997</td>
<td>2,724</td>
</tr>
<tr>
<td>South (w/o Stavely)</td>
<td>877</td>
<td>1,157</td>
<td>1,415</td>
</tr>
</tbody>
</table>
Figure 4.4-2: Region Demand at Time of Summer All Peak Demand

Note: figures in colour denote actuals
4.5 FORECAST RESULTS FOR REGIONAL PLANNING PURPOSES

The Province of Alberta covers over 661,100 square kilometres. This represents approximately seven per cent of Canada’s total land mass. Given the considerable size of the province, it is reasonable to expect the geography, economics and climate will vary from one region to another. This geographical diversity is apparent in the AESO’s load forecast as seen in the tables that follow. Figure 4.5-1 shows the province divided into areas. These areas can be added together to explore electric power needs unique to that particular region.

For regional planning purposes, areas have been grouped to represent six regions: South, Calgary, Central, Edmonton, Northeast and Northwest.

The following tables show regional peak demand coincident for both the summer and winter seasons. The FC2009 results are compared to the forecast numbers for 2014, 2019 and 2029.
Figure 4.5-1: Grouping of Areas for Regional Planning Purposes

[Map showing grouping of areas for regional planning purposes with region names and codes.]
South Region
The South region includes the Medicine Hat, Sheerness, Brooks, Empress, Stavely, Vauxhall, Fort MacLeod, Lethbridge and Glenwood planning areas.

Table 4.5-1: Coincident Peak Demand (MW) for South Region

<table>
<thead>
<tr>
<th>South</th>
<th>FC2009 2009</th>
<th>FC2009 2014</th>
<th>Average Annual Growth (%)</th>
<th>FC2009 2019</th>
<th>Average Annual Growth (%)</th>
<th>FC2009 2029</th>
<th>Average Annual Growth (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td>924</td>
<td>1,034</td>
<td>2.3</td>
<td>1,221</td>
<td>2.6</td>
<td>1,495</td>
<td>2.4</td>
</tr>
<tr>
<td>Summer</td>
<td>1,004</td>
<td>1,108</td>
<td>2.0</td>
<td>1,311</td>
<td>2.7</td>
<td>1,588</td>
<td>2.3</td>
</tr>
</tbody>
</table>

Calgary Region
Included in this region are the Calgary, Strathmore/Blackie, Seebe, High River and Airdrie planning areas. The ENMAX metering points – as supplied by ENMAX – also provide a forecast for the City of Calgary.

Table 4.5-2: Coincident Peak Demand (MW) for Calgary Region

<table>
<thead>
<tr>
<th>Calgary</th>
<th>FC2009 2009</th>
<th>FC2009 2014</th>
<th>Average Annual Growth (%)</th>
<th>FC2009 2019</th>
<th>Average Annual Growth (%)</th>
<th>FC2009 2029</th>
<th>Average Annual Growth (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Calgary Area</td>
<td>1,965</td>
<td>2,323</td>
<td>3.4</td>
<td>2,759</td>
<td>3.4</td>
<td>3,721</td>
<td>3.2</td>
</tr>
<tr>
<td>City of Calgary (ENMAX)</td>
<td>1,440</td>
<td>1,697</td>
<td>3.3</td>
<td>1,997</td>
<td>3.3</td>
<td>2,747</td>
<td>3.3</td>
</tr>
<tr>
<td>Summer</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Calgary Area</td>
<td>1,937</td>
<td>2,268</td>
<td>3.2</td>
<td>2,689</td>
<td>3.3</td>
<td>3,586</td>
<td>3.1</td>
</tr>
<tr>
<td>City of Calgary (ENMAX)</td>
<td>1,462</td>
<td>1,714</td>
<td>3.2</td>
<td>2,024</td>
<td>3.3</td>
<td>2,738</td>
<td>3.2</td>
</tr>
</tbody>
</table>

Central Region
The Central region is considered to be between Edmonton and Calgary. Included are the Lloydminster, Hinton/Edson, Drayton Valley, Wainwright, Abraham Lake, Red Deer, Alliance/Battle River, Provost, Caroline, Didsbury, Hanna and Vegreville planning areas.

Table 4.5-3: Coincident Peak Demand (MW) for Central Region

<table>
<thead>
<tr>
<th>Central</th>
<th>FC2009 2009</th>
<th>FC2009 2014</th>
<th>Average Annual Growth (%)</th>
<th>FC2009 2019</th>
<th>Average Annual Growth (%)</th>
<th>FC2009 2029</th>
<th>Average Annual Growth (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td>1,598</td>
<td>1,900</td>
<td>3.5</td>
<td>2,224</td>
<td>3.4</td>
<td>2,694</td>
<td>2.6</td>
</tr>
<tr>
<td>Summer</td>
<td>1,438</td>
<td>1,664</td>
<td>3.0</td>
<td>1,975</td>
<td>3.2</td>
<td>2,387</td>
<td>2.6</td>
</tr>
</tbody>
</table>
Edmonton Region

Acting as a transmission hub, the Edmonton region includes the Wetaskiwin, Fort Saskatchewan, Wabamun and Edmonton planning areas. The EPCOR metering points – as supplied by EPCOR – also provide a forecast for the City of Edmonton.

Table 4.5-4: Coincident Peak Demand (MW) for Edmonton Region

<table>
<thead>
<tr>
<th>Edmonton</th>
<th>FC2009</th>
<th>FC2009</th>
<th>Average Annual Growth (%)</th>
<th>FC2009</th>
<th>FC2009</th>
<th>Average Annual Growth (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Edmonton Area</td>
<td>2,461</td>
<td>2,825</td>
<td>2.8</td>
<td>3,246</td>
<td>2.8</td>
<td>3,935</td>
</tr>
<tr>
<td>City of Edmonton (EPCOR)</td>
<td>1,199</td>
<td>1,335</td>
<td>2.2</td>
<td>1,572</td>
<td>2.7</td>
<td>1,906</td>
</tr>
<tr>
<td>Summer</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Edmonton Area</td>
<td>2,457</td>
<td>2,704</td>
<td>1.9</td>
<td>3,134</td>
<td>2.5</td>
<td>3,788</td>
</tr>
<tr>
<td>City of Edmonton (EPCOR)</td>
<td>1,203</td>
<td>1,340</td>
<td>2.2</td>
<td>1,584</td>
<td>2.8</td>
<td>1,932</td>
</tr>
</tbody>
</table>

Northeast Region

The Northeast region is forecast to experience the greatest demand and energy growth over the next 10 years. This is due in large part to the oilsands industry. The Northeast region includes the Fort McMurray, Athabasca/Lac La Biche and Cold Lake planning areas.

Table 4.5-5: Coincident Peak Demand (MW) for Northeast Region

<table>
<thead>
<tr>
<th>Northeast</th>
<th>FC2009</th>
<th>FC2009</th>
<th>Average Annual Growth (%)</th>
<th>FC2009</th>
<th>FC2009</th>
<th>Average Annual Growth (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Winter</td>
<td>1,778</td>
<td>2,766</td>
<td>9.2</td>
<td>3,602</td>
<td>7.3</td>
<td>4,752</td>
</tr>
<tr>
<td>Summer</td>
<td>1,657</td>
<td>2,526</td>
<td>8.8</td>
<td>3,358</td>
<td>7.3</td>
<td>4,413</td>
</tr>
</tbody>
</table>

Northwest Region

The Northwest region includes the Rainbow Lake, High Level, Peace River, Grande Prairie, High Prairie, Grand Cache, Valleyview, Fox Creek and Swan Hills planning areas.

Table 4.5-6: Coincident Peak Demand (MW) for Northwest Region

<table>
<thead>
<tr>
<th>Northwest</th>
<th>FC2009</th>
<th>FC2009</th>
<th>Average Annual Growth (%)</th>
<th>FC2009</th>
<th>FC2009</th>
<th>Average Annual Growth (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Winter</td>
<td>1,100</td>
<td>1,363</td>
<td>4.4</td>
<td>1,570</td>
<td>3.6</td>
<td>1,898</td>
</tr>
<tr>
<td>Summer</td>
<td>1,059</td>
<td>1,255</td>
<td>3.5</td>
<td>1,459</td>
<td>3.3</td>
<td>1,740</td>
</tr>
</tbody>
</table>
5.0 Other Load Forecasting Considerations

In addition to the uncertainty associated with economic and demographic variables, there are other significant challenges in developing a long-term load forecast for Alberta. Many of these are addressed implicitly by the AESO’s load forecasting models. Although the factors discussed below are not explicitly included in the load forecasting models, they are examined by the AESO on a regular basis to inform the load forecasting process.

5.1 DEMAND RESPONSIVE LOAD AND CONSERVATION

The potential impact of conservation and efficiency (that will drive or be driven by the advancement of new technologies), and demand responsive load programs represents an additional source of uncertainty and challenge for the AESO’s load forecast. In general, these can be programs that encourage conservation and efficiency, or programs that allow consumers to respond to market signals and voluntarily reduce electricity consumption based on market prices. Another change affecting the forecast relates to the direction given by the system controller to facility owners during unexpected events such as supply shortfall in the form of operational policy and procedures. With such programs, there is potential to reduce or shift the timing of Alberta system peaks and energy requirements.

Current Alberta market design relies primarily on price signals to provide consumer incentives for economically efficient electricity consumption and production decisions. Price responsive load has been seen primarily from industrial customers that have flexible production such that they can turn down operations and respond to high market prices. Depending on the market price, the amount of price responsive load has ranged from 175 to 300 MW.
The AESO has implemented a combination of demand response programs to assist in managing or preventing emergency system operating conditions. These include:

- **Voluntary load curtailment protocol (VLCP)** – a demand response program based on a pre-arranged contract.
- **Demand opportunity service (DOS)** – an opportunity transmission service with regulated rates for each level of interruption (seven minutes and one hour).
- **Frequency load shed service (FLSS)** – load shed instantaneously during system events.
- **Supplemental operating reserves (SUP)** – Ancillary service available to arrest frequency decline but not required to respond directly to frequency deviations. This can be a load or generator service.

The net impact of these programs is captured in the AESO’s long-term load forecast modelling processes. The forecasting models, which are based upon historical values, reflect the historical effect of these programs. As a result, forecasted energy and peak demand values implicitly include the effect of demand response programs.

There is a major emphasis on energy efficiency and conservation programs in various North American jurisdictions, which are encompassed by the term demand side management (DSM). DSM generally refers to activities that occur on the demand side of the meter, and are implemented by the customer directly or by load serving entities. DSM initiatives are aimed at achieving energy savings as a result of conservation, energy efficiency and load displacement programs. A substantial portion of these energy savings has resulted from appliance and building standards. Another major portion of savings are utility programs mandated by governments and regulators, including efficiency services in the form of energy audits, financial incentive, load-shifting activities and rate design.

Several jurisdictions are implementing very aggressive DSM programs including California, the U.S. Pacific Northwest and B.C. For example, BC Hydro is required to acquire 50 per cent of its incremental resource needs through conservation (DSM) by 2020. The approach adopted to load forecasting in these jurisdictions typically involves a detailed assessment of the impact of DSM programs and price effects on electricity demand. These analytical requirements characteristically necessitate an extremely detailed end-use approach to demand forecasting.

To date, load-serving entities or retailers in Alberta have not developed price responsive, efficiency or conservation programs in the same way as other jurisdictions, especially those that rely on the traditional integrated utility model. Consequently, reduction in demand opportunities from this sector to date have been negligible. The potential impacts of demand response and DSM-type programs are not explicitly included in the AESO’s load-forecasting models, given that such programs are not widespread and future programs are unknown at this time. The AESO will continue to evaluate appropriate programs related to DSM.
5.2 COMPOSITION OF LOAD

Industrial load represents a very high percentage of total load in Alberta. This can be expected to contribute to future uncertainty in the load forecast.

Unlike the residential and commercial sectors, where electricity use is relatively similar in different houses or buildings, industrial use of electricity is diverse. It is difficult to generalize about the uses of electricity in a typical industrial plant. Electricity consumption per site is greater in this sector than other sectors. Alberta’s industrial electricity consumption is tied closely to economic activity and world oil and gas market conditions. Beyond the general risk of higher or lower than expected economic growth materializing, a significant risk to the industrial load forecast pertains to discrete one-time, unforeseen changes in load that are the result of corporate decisions that impact the opening, timing, restarting or closing of major facilities.

The oilsands industry in particular, which drives behind-the-fence (BTF) load in Alberta, is very dynamic. These projects have unique attributes in terms of the size, cost, location, labour and electricity requirements. Since oilsands producers are expected to behave differently than the rest of the industrial sector, they are a potential source of uncertainty in the long-term load forecast. This includes the development of specific major oilsands projects, which have announced on-site generation, and projects that are likely to do so. Given the many options available to developers, the volatility of oil prices, and the variability of labour and material costs for constructing new projects, load growth in the oilsands industry is not expected to occur in a smooth, easily predictable manner.
5.3 DISTRIBUTED GENERATION

Distributed generation involves the installation of small-scale power sources at or near a customer’s site to provide an alternative to, or an enhancement of, the traditional electric power system.

For generation smaller than 150 kW, modelling and forecasting of this generation and the load that it offsets is not specifically tracked. Advanced Metering Infrastructure (AMI) and smart grid could facilitate specific tracking of micro and other generation. It is assumed that the impact of any potential drop in load caused by distributed generation will be captured through trends seen in the econometric modelling of electricity consumption by sector. Major shifts can be addressed as they are identified.

5.4 ENVIRONMENTAL COSTS

The costs of meeting environmental requirements are expected to rise across North America, particularly for large greenhouse gas (GHG) emitters. While this may have an impact on the in-service dates for some oilsands and upgrader projects, at this time there is no basis for assuming these costs will significantly slow expansion in Alberta’s energy producing sectors. Because it is unlikely that reduction in GHG emissions will occur without cost, future climate control policy is a risk of uncertain magnitude and timing to the load forecast. Load forecasting models used in other jurisdictions generally tend to use a fuel carbon content tax as a proxy for the cost of mandated GHG reductions, whatever the means of implementation.

It can be expected that any costs associated with meeting environmental requirements for electricity generation facilities in the future will ultimately be reflected in electricity prices. As previously discussed, the AESO’s load-forecasting models do not explicitly include the influence of electricity prices on electricity demand. However, any changes in demand patterns are captured through the modelling process that accounts for historic trends that capture various econometric drivers.
5.5 CHALLENGES ON THE HORIZON

This year a number of future challenges have been identified:

- New DSM initiatives, including demand response programs.
- New technology with different electricity intensities.
- New environmental regulations around GHG.
- New vehicle technology, including plug-in electric cars.

Each of these challenges will be explored in the coming year to determine their significance with respect to the fundamental relationships that form the basis of the AESO’s Future Demand and Energy Outlook (2009 – 2029).
6.0 Historical and Past Forecast Results

In the process of preparing the long-term load forecast, the AESO assesses past forecasts along with Alberta’s actual demand and electricity usage to verify methodology and identify variances that could impact the current forecast.

6.1 PAST FORECAST VARIANCES

<table>
<thead>
<tr>
<th>Year</th>
<th>Actuals (GWh)</th>
<th>Year-over-Year Change</th>
<th>FC2005 (%)</th>
<th>FC2006 (%)</th>
<th>FC2007 (%)</th>
<th>FC2008 (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006</td>
<td>69,371</td>
<td>-</td>
<td>-1</td>
<td>+1.</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2007</td>
<td>69,660</td>
<td>+290</td>
<td>-3</td>
<td>-1</td>
<td>-1</td>
<td>-</td>
</tr>
<tr>
<td>2008</td>
<td>69,947</td>
<td>+286</td>
<td>-7</td>
<td>-4</td>
<td>-4</td>
<td>-1</td>
</tr>
<tr>
<td>2009</td>
<td>70,150</td>
<td>+204</td>
<td>-9</td>
<td>-7</td>
<td>-8</td>
<td>-4</td>
</tr>
</tbody>
</table>

As noted in Section 3.7, a reduction in demand at 10 industrial sites contributed to a reduction in energy growth in the province at the same time as strong growth in the oilsands and a strong economy created energy growth in other customer sectors and industries. To quantify the effect this drop in electricity consumption has had on energy growth, the AESO adjusted historical energy values by adding an Adjustment Factor equal to the difference between the sum of energy at these sites in 2005 minus the sum of energy at these sites in each historical year. The year 2005 was used as a representative year in this analysis to calculate a baseline. The results are shown in Table 6.1-2.
Table 6.1-2: Historical Energy with Adjustments for 10 Industrial Sites’ Reduction in Load

<table>
<thead>
<tr>
<th>Year</th>
<th>Adjusted Actuals (GWh)</th>
<th>Adjustment Factor (GWh)</th>
<th>Adjustment Year over Growth (%)</th>
<th>5-year Adjustment Average Growth (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2003</td>
<td>62,716</td>
<td>–</td>
<td>5.5</td>
<td>–</td>
</tr>
<tr>
<td>2004</td>
<td>65,259</td>
<td>–</td>
<td>4.1</td>
<td>–</td>
</tr>
<tr>
<td>2005</td>
<td>66,268</td>
<td>–</td>
<td>1.5</td>
<td>–</td>
</tr>
<tr>
<td>2006</td>
<td>69,794</td>
<td>+423</td>
<td>5.3</td>
<td>+5.1</td>
</tr>
<tr>
<td>2007</td>
<td>71,383</td>
<td>+1,724</td>
<td>2.3</td>
<td>+3.7</td>
</tr>
<tr>
<td>2008</td>
<td>72,322</td>
<td>+2,375</td>
<td>1.3</td>
<td>+2.9</td>
</tr>
</tbody>
</table>

Table 6.1-3 examines the variance between actual peak demand and forecast peak demand. The winter peak demand in 2005/06 and 2009/10 was higher than forecast, while the winter peak demand for both 2006/07 and 2007/08 was lower than forecast.

Table 6.1-3: Peak Forecast Variance History

<table>
<thead>
<tr>
<th>Year/Season</th>
<th>Actuals (MW)</th>
<th>Year-over-Year Change</th>
<th>Season-over-Season</th>
<th>FC2005 (%)</th>
<th>FC2006 (%)</th>
<th>FC2007 (%)</th>
<th>FC2008 (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005/06 Winter</td>
<td>9,580</td>
<td>–</td>
<td>–</td>
<td>+0.5</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>2006 Summer</td>
<td>9,050</td>
<td>–</td>
<td>-530</td>
<td>-2.4</td>
<td>+2.3</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>2006/07 Winter</td>
<td>9,661</td>
<td>+81</td>
<td>+611</td>
<td>-4.0</td>
<td>-3.8</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>2007 Summer</td>
<td>9,321</td>
<td>+271</td>
<td>-340</td>
<td>-2.6</td>
<td>+2.4</td>
<td>+1.0</td>
<td>–</td>
</tr>
<tr>
<td>2007/08 Winter</td>
<td>9,710</td>
<td>+49</td>
<td>+389</td>
<td>-5.6</td>
<td>-5.4</td>
<td>-3.2</td>
<td>–</td>
</tr>
<tr>
<td>2008 Summer</td>
<td>9,541</td>
<td>+220</td>
<td>-169</td>
<td>-4.0</td>
<td>+1.2</td>
<td>+0.3</td>
<td>+1.0</td>
</tr>
<tr>
<td>2008/09 Winter</td>
<td>9,806</td>
<td>+96</td>
<td>+265</td>
<td>-8.1</td>
<td>-8.0</td>
<td>+6.3</td>
<td>-0.3</td>
</tr>
<tr>
<td>2009 Summer</td>
<td>9,108</td>
<td>-433</td>
<td>-698</td>
<td>-10.5</td>
<td>-6.2</td>
<td>-8.9</td>
<td>-8.0</td>
</tr>
<tr>
<td>2009/010 YTD Winter</td>
<td>10,236</td>
<td>+430</td>
<td>+1,128</td>
<td>-6.5</td>
<td>-6.2</td>
<td>-5.2</td>
<td>+0.3</td>
</tr>
</tbody>
</table>
Appendix A:
Confidence Band Intervals for the
Future Demand and Energy Outlook
(2009 – 2029)

Executive Summary

This appendix describes the methodology and results of constructing confidence band intervals around the Alberta electric system’s long-term load forecast, as laid out in Future Demand and Energy Outlook (2009 – 2029) (FC2009).

The FC2009 is the Alberta Electric System Operator’s (AESO) long-term load forecast. The FC2009 describes the assumptions, methodology, and processes that the AESO uses to assess Alberta’s most likely future demand and energy requirements.

The FC2009 includes a 20-year peak demand and electricity consumption forecast for Alberta. The load forecast is generated from economic growth (GDP), oilsands production forecasts and population projections by select customer sectors in conjunction with regional adjustments based on historical results and customer-driven growth expectations.

The report shows confidence intervals on a sector-by-sector basis at the 80 per cent (P10 to P90) and 95 per cent (P2.5 to P97.5) confidence levels. The confidence intervals are derived using a Monte Carlo simulation model where inputs into the forecasting model are varied according to a predetermined probability distribution multiple times. Output from the model is then analyzed for statistical properties.

The results of the Monte Carlo approach show P10/90 low/high peak demand values of 13,510 MW (-8.5 per cent) and 16,133 MW (+9.3 per cent) respectively by 2019, as compared to the most likely forecast of 14,759 MW. The results for 2029 show a wider spread for the P10/P90 of 17,001 MW (-9.1 per cent) and 20,560 MW (+10.0 per cent) respectively as compared to the most likely forecast of 18,695 MW.
1.0 Introduction

The AESO’s long-term load forecast is a study of past energy use patterns and future economic indicators that are combined to produce a future energy forecast. The AESO annually updates this energy forecast with a 20-year outlook of Alberta’s electric consumption and peak demand. The estimates of future electricity market needs are one of the drivers the AESO uses in analyzing and planning the timely development of the transmission system. The annual forecast is based on economic, demographic and customer information collected from January through June of 2009.

The FC2009 describes the assumptions, methodology and processes that the AESO employs to assess Alberta’s most likely future demand and energy requirements.

Along with its long-term load forecast, the AESO requires high and low confidence bands that reflect a reasonable expected range of the forecast. Potential sources of error exist with any forecast and it is important to recognize and attempt to measure the potential effect that any error may have on the forecast. The assumptions used and the underlying methodology of forecasting are explained to justify why the confidence bands represent a relatively likely forecast.

Forecasts cannot precisely predict the future. Variation in the key factors that drive electrical usage may deviate actual demand from forecast demand in any given year. To account for this, the AESO reports its energy and demand forecast as a baseline or most likely outcome, as well as a range of possible outcomes based on probabilities around the base case. For planning and analytical purposes, it is useful to have an estimate not only of the most likely case but also of the distribution of probabilities around the forecast.

The AESO developed upper and lower confidence bands around the 2009 load forecast for each sector. The P2.5/P97.5 confidence band corresponds to a 95 per cent confidence interval. This means there is a 95 per cent chance that the actual energy demand will fall within this interval and there is a five per cent chance actual demand will fall outside this interval. Similarly, the P10/P90 confidence band corresponds to an 80 per cent confidence interval for which there is an 80 per cent chance that the forecast will fall within its bands.

A Monte Carlo simulation method was used to calculate confidence band intervals for each sector as well as for total Alberta internal load (AIL) and peak demand. Monte Carlo simulations vary the inputs into the forecasting models according to a calculated probability distribution based on historical data. Output results from the model are then analyzed for their statistical properties to determine the confidence intervals. This method of determining confidence bands has the advantage of varying all the factors that affect electricity use and demand according to their historical tendencies multiple times so actual variation in the forecast can be measured and analyzed.
2.0 Monte Carlo Analysis

Monte Carlo simulations were performed individually on all five sector models as well as on an aggregated model, which combines all the sectors together. Within the models there are econometrically forecasted coefficients as well as externally-forecast values of input variables. All variables are allowed to vary according to defined probability distributions that are based on historical data wherever possible. It should be noted that in many instances historical data was not available, or was not adequate to produce a reasonable probability distribution estimate. In these instances, the AESO formulated its own estimate of probability distribution using the forecast values plus a reasonable assessment of potential variation for those forecast values.
2.1 INDUSTRIAL (WITHOUT OILSANDS) CUSTOMER SECTOR

The industrial sector is the largest sector in terms of electricity consumption, comprising roughly 45 per cent of total AIL energy. The forecast for this sector is a function of real economic growth and historical usage.

The industrial forecast was completed using an Ordinary Least Squares (OLS) econometric regression, which included Alberta mining, oil and gas GDP, previous industrial sales and control variables. The inputs into the industrial (without oilsands) model consist of the estimated coefficients from the econometric regression plus The Conference Board of Canada’s mining, oil and gas GDP forecast. A normal distribution was assumed for both the regression coefficients and the growth rates of the GDP forecast in each year. There are 26 total input variables that received a probability distribution. A random sample from each of those 26 probability distributions was put into the model to calculate the corresponding forecast value. This process was repeated 100,000 times providing 100,000 forecast values for each year of the forecast. Using these values, the 80 per cent and 95 per cent forecast confidence band intervals were calculated. These values are shown in Figure 2.1-1.

Figure 2.1-1: Industrial (without Oilsands) Sector Confidence Intervals

![Figure 2.1-1: Industrial (without Oilsands) Sector Confidence Intervals](image)

Source: AESO and ERCB
2.2 OILSANDS CUSTOMER SECTOR

The oilsands model has several variable inputs. Production from the oilsands is broken into mining, in situ and upgraded bitumen production. Using historical data, estimates are made on the energy intensity of the three production types. Production estimates for each production type are then combined with the estimated energy intensity to produce an oilsands forecast.

As outlined in the FC2009, the oilsands production estimates up to 2025 are based on the Canadian Association of Petroleum Producers’ (CAPP) moderate growth oilsands production forecast. Thereafter, the AESO estimates of growth are used. Probability distributions are estimated for the growth of each year with mean equal to the forecast growth rate.

The AESO estimates the energy intensities of the three oilsands production types. However, it is unknown how these intensities may change over time. Therefore, the energy intensities are permitted to vary using a normal probability distribution that allows both increases and decreases in energy intensity. This allows the confidence bands to incorporate the possibility that energy intensity of mining, in situ or bitumen upgrading may independently increase or decrease over time. 100,000 random samples were taken from each probability distribution of each input variable and put into the model to calculate the corresponding forecast values, which were used to calculate the confidence intervals. Figure 2.2-1 shows the calculated 80 per cent and 95 per cent confidence band intervals.

Figure 2.2-1: Oilsands Sector Confidence Intervals

Source: AESO and ERCB
2.3 COMMERCIAL CUSTOMER SECTOR

The commercial sector represents approximately 19 per cent of total energy in Alberta. The commercial sector forecast assumes commercial energy use is a function of Alberta’s economic growth and historical commercial sales.

Commercial electricity consumption is forecast by the AESO using an econometric regression, which includes Alberta GDP, historical commercial sales and control variables. The Conference Board of Canada’s forecast of Alberta GDP is also used as an input.

For the Monte Carlo simulation, the regression coefficients are assumed to be normally distributed. The annual GDP growth rates are also assumed to have a normal distribution with the mean centered on the forecast values. The standard deviation used is calculated from historical values. Similar to the other sectors, 100,000 samples are taken from each input’s distribution, which are put through the model and used to calculate the forecast confidence intervals. These calculated confidence intervals are displayed in Figure 2.3-1.

Figure 2.3-1: Commercial Sector Confidence Intervals

Source: AESO and ERCB
2.4 RESIDENTIAL CUSTOMER SECTOR

Residential energy use represents approximately 13 per cent of AIL energy. As outlined in the FC2009, the residential model is an econometric regression combined with The Conference Board of Canada’s growth forecasts of population and disposable income per person. The coefficients of the regression are assumed to be normal for the Monte Carlo simulation. Population and disposable income per person growth rates are also assumed to be normally distributed and are based on historical trends.

In a similar fashion to the other sectors, a Monte Carlo simulation of the residential forecast was used to estimate confidence band intervals at 80 per cent and 95 per cent. These estimates are shown in Figure 2.4-1.

Figure 2.4-1: Residential Sector Confidence Intervals

Source: AESO and ERCB
2.5 FARM CUSTOMER SECTOR

The farm sector is the smallest of the forecast sectors, representing approximately three per cent of total AIL energy. As outlined in the FC2009, no growth is forecast from the farm sector over the next 20 years. However, based on historical recorded values and variance, a normal growth rate probability distribution was applied to farm sales for the Monte Carlo simulation, which allows for yearly variation as well as the possibility of technological change to agricultural and irrigation techniques.

Repeatedly taking samples from the growth rate probability distribution allowed the construction of the farm forecast confidence intervals, which are shown in Figure 2.5-1.

Figure 2.5-1: Farm Sector Confidence Intervals
3.0 Total Energy and Peak Demand

Total provincial energy use and peak demand were also calculated using the Monte Carlo simulation, which took inputs from each sector and combined them in a comprehensive model to produce a total energy forecast. This total energy forecast was converted into peak demand using the FC2009 load factor estimate, which was also varied using historical trends.

3.1 MONTE CARLO RESULTS

For the Monte Carlo simulation, the five sector models were combined into one model to calculate total AIL energy as well as the corresponding peak demand. The transmission and distribution losses were each permitted to vary based upon historical fluctuations in losses as a percentage of sector energy. The ‘Other’ category was not varied as part of the Monte Carlo simulation. The forecast values remain calculated in the same way. However, the input variables of all five models are permitted to vary simultaneously according to the distributions outlined in Section 2.0. By varying all sector inputs simultaneously, the confidence bands for total AIL peak demand and energy are dependent on the variation of all inputs. The calculated AIL confidence bands and their corresponding peak demand and energy confidence intervals are displayed in Figures 3.1-1 and 3.1-2.

Figure 3.1-1: AIL Energy Confidence Intervals

Source: AESO and ERCB
Tables 3.1-1 and 3.1-2 report the confidence interval results from the Monte Carlo simulation on AIL energy and peak demand respectively. The results of the Monte Carlo approach show P10/90 low/high peak demand values of 13,510 MW (-8.5 per cent) and 16,133 MW (+9.3 per cent) respectively by 2019 as compared to the most likely forecast of 14,759 MW. The results for 2029 show a wider spread for the P10/P90 of 17,001 MW (-9.1 per cent) and 20,560 MW (+10.0 per cent) respectively as compared to the most likely forecast of 18,695 MW.
Additional analysis indicates that by 2029, the largest source of variation in the AIL energy forecast will come from the industrial sector. Specifically, the coefficient on the mining, oil and gas GDP contributes most to overall variation. While statistically significant, the coefficient had a relatively high standard error resulting both from fairly low degrees of freedom (because of a relatively low number of annual observations) and from a recent historical divergence of industrial energy use and mining, oil and gas GDP. As discussed in the FC2009, the decrease in industrial energy use resulted from the exit and decrease in activity of several non-oil and gas-related firms that are not part of mining, oil and gas GDP.

Going forward, it is expected that industrial energy use will continue to increase with mining, oil and gas GDP since the majority of industrial energy use is by the oil and gas sector. However, because of the recent industrial decline, certainty surrounding the coefficient on mining, oil and gas GDP is less assured. This creates additional variation in the industrial (without oilsands) sector confidence bands. Since the industrial (without oilsands) sector is the largest component of AIL energy, it also creates the largest source of variation in the total AIL energy forecast confidence bands. Given the difficulty to predict the exit or decrease in activity of industrial firms, this higher variation seen in the industrial sector seems appropriate.
<table>
<thead>
<tr>
<th></th>
<th>FC2009 (GWh)</th>
<th>P97.5 (GWh)</th>
<th>P90 (GWh)</th>
<th>P10 (GWh)</th>
<th>P2.5 (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>70,184</td>
<td>74,391</td>
<td>72,903</td>
<td>67,426</td>
<td>66,001</td>
</tr>
<tr>
<td>2010</td>
<td>72,459</td>
<td>78,845</td>
<td>76,573</td>
<td>68,466</td>
<td>66,423</td>
</tr>
<tr>
<td>2011</td>
<td>75,312</td>
<td>83,270</td>
<td>80,438</td>
<td>70,451</td>
<td>67,961</td>
</tr>
<tr>
<td>2012</td>
<td>78,963</td>
<td>88,164</td>
<td>84,866</td>
<td>73,416</td>
<td>70,577</td>
</tr>
<tr>
<td>2013</td>
<td>82,877</td>
<td>93,101</td>
<td>89,459</td>
<td>76,738</td>
<td>73,632</td>
</tr>
<tr>
<td>2014</td>
<td>86,965</td>
<td>98,221</td>
<td>94,160</td>
<td>80,289</td>
<td>76,922</td>
</tr>
<tr>
<td>2015</td>
<td>90,900</td>
<td>103,019</td>
<td>98,638</td>
<td>83,779</td>
<td>80,190</td>
</tr>
<tr>
<td>2016</td>
<td>95,335</td>
<td>108,284</td>
<td>103,556</td>
<td>87,740</td>
<td>83,877</td>
</tr>
<tr>
<td>2017</td>
<td>98,870</td>
<td>112,585</td>
<td>107,593</td>
<td>90,867</td>
<td>86,827</td>
</tr>
<tr>
<td>2018</td>
<td>102,220</td>
<td>116,613</td>
<td>111,369</td>
<td>93,831</td>
<td>89,642</td>
</tr>
<tr>
<td>2019</td>
<td>105,344</td>
<td>120,318</td>
<td>114,887</td>
<td>96,640</td>
<td>92,260</td>
</tr>
<tr>
<td>2020</td>
<td>108,638</td>
<td>124,304</td>
<td>118,598</td>
<td>99,619</td>
<td>95,059</td>
</tr>
<tr>
<td>2021</td>
<td>111,208</td>
<td>127,305</td>
<td>121,479</td>
<td>101,866</td>
<td>97,144</td>
</tr>
<tr>
<td>2022</td>
<td>113,923</td>
<td>130,567</td>
<td>124,516</td>
<td>104,264</td>
<td>99,478</td>
</tr>
<tr>
<td>2023</td>
<td>116,691</td>
<td>133,939</td>
<td>127,608</td>
<td>106,731</td>
<td>101,722</td>
</tr>
<tr>
<td>2024</td>
<td>119,261</td>
<td>136,845</td>
<td>130,501</td>
<td>109,051</td>
<td>103,890</td>
</tr>
<tr>
<td>2025</td>
<td>121,640</td>
<td>139,811</td>
<td>133,207</td>
<td>111,164</td>
<td>105,845</td>
</tr>
<tr>
<td>2026</td>
<td>124,355</td>
<td>143,038</td>
<td>136,247</td>
<td>113,528</td>
<td>108,115</td>
</tr>
<tr>
<td>2027</td>
<td>127,096</td>
<td>146,394</td>
<td>139,288</td>
<td>115,957</td>
<td>110,401</td>
</tr>
<tr>
<td>2028</td>
<td>129,911</td>
<td>149,609</td>
<td>142,463</td>
<td>118,451</td>
<td>112,687</td>
</tr>
<tr>
<td>2029</td>
<td>132,746</td>
<td>153,145</td>
<td>145,620</td>
<td>120,979</td>
<td>115,096</td>
</tr>
<tr>
<td></td>
<td>FC2009 MW</td>
<td>P97.5 MW</td>
<td>P90 MW</td>
<td>P10 MW</td>
<td>P2.5 MW</td>
</tr>
<tr>
<td>----------</td>
<td>-----------</td>
<td>----------</td>
<td>--------</td>
<td>--------</td>
<td>--------</td>
</tr>
<tr>
<td>2009/10</td>
<td>9,846</td>
<td>10,519</td>
<td>10,284</td>
<td>9,422</td>
<td>9,201</td>
</tr>
<tr>
<td>2010/11</td>
<td>10,170</td>
<td>11,124</td>
<td>10,788</td>
<td>9,579</td>
<td>9,281</td>
</tr>
<tr>
<td>2011/12</td>
<td>10,577</td>
<td>11,746</td>
<td>11,328</td>
<td>9,866</td>
<td>9,503</td>
</tr>
<tr>
<td>2012/13</td>
<td>11,076</td>
<td>12,418</td>
<td>11,938</td>
<td>10,270</td>
<td>9,870</td>
</tr>
<tr>
<td>2013/14</td>
<td>11,664</td>
<td>13,155</td>
<td>12,620</td>
<td>10,776</td>
<td>10,329</td>
</tr>
<tr>
<td>2014/15</td>
<td>12,162</td>
<td>13,782</td>
<td>13,200</td>
<td>11,201</td>
<td>10,718</td>
</tr>
<tr>
<td>2015/16</td>
<td>12,801</td>
<td>14,553</td>
<td>13,923</td>
<td>11,774</td>
<td>11,260</td>
</tr>
<tr>
<td>2016/17</td>
<td>13,382</td>
<td>15,254</td>
<td>14,576</td>
<td>12,288</td>
<td>11,730</td>
</tr>
<tr>
<td>2017/18</td>
<td>13,856</td>
<td>15,828</td>
<td>15,113</td>
<td>12,704</td>
<td>12,132</td>
</tr>
<tr>
<td>2018/19</td>
<td>14,351</td>
<td>16,419</td>
<td>15,671</td>
<td>13,146</td>
<td>12,537</td>
</tr>
<tr>
<td>2019/20</td>
<td>14,759</td>
<td>16,923</td>
<td>16,133</td>
<td>13,510</td>
<td>12,883</td>
</tr>
<tr>
<td>2020/21</td>
<td>15,162</td>
<td>17,394</td>
<td>16,590</td>
<td>13,872</td>
<td>13,221</td>
</tr>
<tr>
<td>2021/22</td>
<td>15,618</td>
<td>17,944</td>
<td>17,098</td>
<td>14,271</td>
<td>13,588</td>
</tr>
<tr>
<td>2022/23</td>
<td>15,994</td>
<td>18,397</td>
<td>17,520</td>
<td>14,607</td>
<td>13,911</td>
</tr>
<tr>
<td>2023/24</td>
<td>16,369</td>
<td>18,838</td>
<td>17,942</td>
<td>14,943</td>
<td>14,225</td>
</tr>
<tr>
<td>2024/25</td>
<td>16,725</td>
<td>19,254</td>
<td>18,341</td>
<td>15,259</td>
<td>14,532</td>
</tr>
<tr>
<td>2025/26</td>
<td>17,114</td>
<td>19,741</td>
<td>18,782</td>
<td>15,600</td>
<td>14,848</td>
</tr>
<tr>
<td>2026/27</td>
<td>17,505</td>
<td>20,203</td>
<td>19,221</td>
<td>15,957</td>
<td>15,173</td>
</tr>
<tr>
<td>2027/28</td>
<td>17,855</td>
<td>20,638</td>
<td>19,608</td>
<td>16,257</td>
<td>15,465</td>
</tr>
<tr>
<td>2028/29</td>
<td>18,196</td>
<td>21,032</td>
<td>19,999</td>
<td>16,561</td>
<td>15,747</td>
</tr>
<tr>
<td>2029/30</td>
<td>18,695</td>
<td>21,625</td>
<td>20,560</td>
<td>17,001</td>
<td>16,156</td>
</tr>
</tbody>
</table>
List of Reference Documents

Alberta Employment, Immigration, and Industry (December 2008)
   Monthly Economic Review

Energy Resources and Conservation Board

Energy Resources and Conservation Board
   Table 11: Electric Energy Distribution Sales and Number of Customers

Canadian Association of Petroleum Producers (June 2009)
   Crude Oil Forecast, Markets and Pipeline Expansions

The Conference Board of Canada (2009)
   Provincial Outlook Long-term Economic Forecast: 2009

The Conference Board of Canada (2009)
   Provincial Outlook Spring 2009

National Energy Board (June 2006)
   Canada’s Oil Sands – Opportunities and Challenges to 2015: An Update. (Review only)

Statistics Canada (December 2008)
   Retail Sales by Industry (monthly)

Statistics Canada (March 2009)
   Alberta Gross Domestic Product at Basic Prices by Industry (annual)

Statistics Canada (March 2009)
   Alberta Population (annual)
Glossary

Alberta Interconnected Electric System (AIES): the system of interconnected transmission power lines and generators.

Alberta internal load (AIL): the total electricity consumption including behind-the-fence, the City of Medicine Hat and losses (transmission and distribution).

Behind-the-fence load (BTF): industrial load characterized by being served in whole, or in part, by on-site generation.

Bulk transmission system: the integrated system of transmission lines and substations that delivers electric power from major generating stations to load centers. The bulk system, which generally includes the 240 kV and 500 kV transmission lines and substations, also delivers/receives power to and from adjacent power systems.

Capacity: amount of electric power delivered or required for a generator, turbine, transformer, transmission circuit, substation or system as rated by the manufacturer.

Customer sectors: used to classify types of load. For the purposes of this report, five sectors were used: industrial (without oilsands), oilsands, residential, commercial and farm.

Demand (coincident demand): a maximum electricity load in a given period of time for a defined area with the units kW (kilowatt) or MW (megawatt).

Demand responsive load or price responsive load: large commercial and industrial customers with flexibility in their operations that enables them to reduce load or demand in response to market price signals or other directions from a system controller.

Demand side management (DSM): generally refers to activities that occur on the demand side of the meter that are implemented by the customer directly or by load serving entities.

Energy: electricity consumption over a given period of time for a defined area with the units kWh (kilowatt hour), MWh (megawatt hour) or GWh (gigawatt hour).

Gigawatt hour (GWh): one billion watt hours.
**Gross domestic product (GDP):** one of the measures of national income and output for a given country’s economy. GDP is defined as the total market value of all final goods and services produced within the country in a given period of time (usually a calendar year). It is also considered the sum of a value added at every stage of production (the intermediate stages) of all final goods and services produced within a country in a given period of time, and it is given a monetary value.

**Load factor:** ratio of average power demand (load) to peak load during a specified period of time; sometimes expressed as a per cent.

**Megawatt (MW):** one million Watts.

**Metering point identifier (MP_ID):** defined point of connection on the transmission provider’s system where capacity and/or energy are made available to the end user.

**Seasonal coincident peak:** a coincident peak measured within a specific period of time defined as a season; typically summer and winter are used but fall and spring can be included as well.

**Substation/switching station:** a facility where equipment is used to tie together two or more electric circuits through switches (circuit breakers). The switches are selectively arranged to permit a circuit to be disconnected or to change the electric connection between the circuits.

**Transmission losses:** energy that is lost through the process of transmitting electrical energy.

**Transmission system (electric):** an interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers, or is delivered to other electric systems.
This page intentionally left blank.
Appendix E
Generation Outlook 2009 – 2029

This section presents the baseline generation scenario and test generation scenarios that are used in the development of the Long-term Transmission Plan (filed June 2012) – also referred to as the LTP or the Plan. It is recognized that generation development in Alberta is a non-regulated, competitive business and it is not possible to definitively describe the timing and location of generation facilities 20 years into the future. The AESO has created a baseline generation scenario that represents the most likely outcome. In addition, to capture the major uncertainties affecting generation development additional generation scenarios are created, against which the transmission system can be tested to identify where future reinforcements are required if generation development deviates from the baseline.

The generation scenarios are based on the transmission policy and market structure currently in place and the assumption that transmission is not a constraint in locating new generation. The generation scenarios do, however, anticipate future changes in the market related to environmental standards, technology development, increasing fuel costs and changing capital and operating costs.

- **Section 1.0** Key drivers describe a number of key drivers that have an impact on the development of generation.
- **Section 2.0** Generation technology options details the generation resources available for development in Alberta.
- **Section 3.0** Comparative costs of generation technology options.
- **Section 4.0** Baseline generation and scenarios describe the baseline generation outlook and generation scenarios to meet future capacity requirements.
1.0 KEY DRIVERS

There are many factors that affect generation developers’ decisions regarding when and where new power plants are built in Alberta. These include resource availability, the state of technology development, relative generation costs, environmental constraints, market structure, intertie capacity, and the ability to finance projects in a competitive marketplace.

In Alberta, generation developers have diverse resources available for power projects. These include coal, natural gas, hydro, wind, biomass and other renewables. The availability and relative costs of the different resources and technologies are a key factor in generation development. These factors are investigated in more detail throughout Sections 3.0 and 4.0. Environmental policies, and their future requirements, have an impact on the relative costs of generation. Climate change policy and estimated costs to meet emission standards are incorporated into the relative costs calculated in Section 4.0.

While Alberta’s energy-only market structure presents challenges for financing power generation projects that are large capacity and high capital cost types of investments, large projects remain viable options in the province. The capability of interties with other jurisdictions is another important consideration for power generation developers. Alberta is one of the least interconnected jurisdictions in Canada. Additional interties increase the ability for Alberta generators to sell surplus energy during off-peak periods. New interties also provide access to more sources of supply during on-peak periods. These benefits can promote generation investment in Alberta and reduce price volatility in the market.

Technology options, relative costs of generation and environmental factors are discussed in the following sections and are considered in the development of the generation scenarios.

2.0 GENERATION TECHNOLOGY OPTIONS

Alberta generation opportunities available for development are influenced by the resources within the province. Alberta has many resources that are available and this can allow for a diverse mix of technologies. Further, the location of resources within Alberta will in most cases dictate where generation development will occur.

There are large amounts of coal in central Alberta, wind resources in southern and central Alberta, forest wood waste energy available in the northwest portion of the province, and the potential for hydro energy on some of the large waterways. Besides these natural resources, an extensive network of pipelines allows gas-fired generation to be located throughout the province. Industrial growth in the province, especially related to oilsands, will allow for the potential of cogeneration units to be built. Smaller scale sources of energy such as solar and waste heat are other sources of energy available in Alberta.

With a variety of resources in Alberta, there are many options for generation development. This section describes these resources, focusing on the applicable generation technologies to convert the resources into electricity, and describes the current generation fleet and the potential for future development. This information is one of the major inputs used in the development of the generation baseline and scenarios.
Figure 2-1: Geographic location of available resources

- Existing transmission lines
- Lakes and rivers
- Oilsands development leases
- Coal fields
- Forestry management areas
- Wind resources
**Hydroelectric power**

Alberta has a total installed capacity of 879 megawatts (MW) of hydroelectric generation that represents seven per cent of the total installed capacity in the province. A majority of the total hydro system in Alberta is from the Bow River hydro system, the Brazeau hydro plant and the Bighorn hydro plant. These plants total 790 MW and are a major source of operating reserves and peaking capacity. The remaining hydro capacity totals 89 MW, and is located in the south from plants ranging in size from the seven MW Irricana project to the 32 MW Oldman River project. These relatively small hydro projects either do not have significant storage, or use the storage they do have primarily for irrigation during the summer months.

There are five main rivers basins where additional hydroelectric generation could be developed. These river basins are the Athabasca River Basin, the Peace River Basin, the Slave River Basin, the North Saskatchewan River Basin and the South Saskatchewan River Basin. Of these, the Athabasca, Peace and Slave River basins contain a majority of the resource potential in the province. The Athabasca River Basin runs from the Rocky Mountains east of Edmonton northeast to Athabasca Lake in the northeastern part of the province. The Peace River Basin is located north of the Athabasca River Basin, starting in the Rocky Mountains and running northeast to the northeast corner of the province. The Slave River Basin is located in the northeast at the border with the Northwest Territories.

Two potential hydro projects on the Peace and Slave systems have been considered by project proponents. The first is the Dunvegan Hydroelectric Project that is proposed by TransAlta on the Peace River. This is a 100 MW run-of-river project and has received regulatory approval. Construction of this project would take about three to four years, would consist of 40 turbine units, and could provide approximately 600,000 megawatt hours per year. The second project on the Slave River is near the boundary of Alberta and the Northwest Territories. A feasibility study of the Slave River Hydro Project sponsored by the Alberta government was completed in 1982. The preferred alternative identified in the feasibility study included a dam located about a kilometre south of the Alberta/N.W.T. border. The installed capacity of this Slave River project proposal would be approximately 1,500 MW and have an estimated capacity factor of 56 per cent. This project was investigated by TransCanada and ATCO but was recently halted. The resources are still available and could be developed in the future.
Figure 2-2: Geographic location of hydroelectric resources
Coal-fired generation

Coal-fired generation is baseload generation and produces approximately 60 per cent of the electricity produced in Alberta. A typical coal plant in Alberta will run at around an 80 per cent capacity factor. This baseload energy is important as it provides large amounts of reliable power to consumers. Alberta has six coal-fired power generation plants with a total installed capacity of 5,782 MW. This represents 44 per cent of the installed capacity and is the largest source of energy in Alberta. The largest plant is the 2,151 MW Sundance facility, which contains six units ranging in size from 288 MW to 406 MW. The Sundance facility is located in central Alberta west of Edmonton. In February 2011, TransAlta issued a notice of termination for destruction of units 1 and 2 after determining that the units cannot be economically restored to service. Other facilities located in the central area are the 780 MW Keephills and the 1,230 MW Genesee facilities. A new unit is currently under construction at the Keephills plant. The new 450 MW Keephills 3 unit is expected to be energized in 2011. Southern coal plants include the 780 MW Sheerness and 697 MW Battle River facilities that are located east of Red Deer. The 144 MW H.R. Milner facility is located in the northwest part of Alberta and is the smallest facility. In March 2010, the last of TransAlta’s Wabamun coal-fired generation units, 279 MW, Wabamun 4, was decommissioned after 54 years of service.

The new coal-fired technology applied in Alberta is supercritical pulverized coal. This technology crushes coal into a fine dust that is burned at high temperatures and pressure to produce steam that powers a turbine. The higher temperatures create a more efficient process than previous subcritical coal technologies. The higher efficiencies of these supercritical units reduce their coal consumption and carbon dioxide (CO₂) emissions per megawatt hour (MWh) produced. Whereas subcritical units, such as units 1 and 2 at Keephills and Genesee, have CO₂ emissions of about one tonne/MWh, the supercritical units are about 10 per cent lower at 0.9 tonnes/MWh. Ultra supercritical units, which achieve higher efficiencies and are starting to be built in parts of the world, further reduce CO₂ emissions to about 0.75 tonne/MWh.

Alberta’s large coal resources are estimated to be 34 billion tonnes, equivalent to 1,000 years of supply at the province’s current production rate of just over 30 million tonnes per year. A significant portion of the 34 billion tonnes of reserves can be mined using open-pit methods. The large amount of coal resources could provide Alberta with future energy requirements. These coal reserves form a large arc from northwest of Edmonton to southeast of Calgary, with coal quality declining from northwest to southeast. Not all of the coal in Alberta would be economically viable for power production.

In June 2010 the Government of Canada made an announcement of proposed regulations on coal-fired emission requirements. The emission regulations would apply to new coal-fired units and units that have reached the end of their economic life and would require these units to meet an emissions intensity level of a natural gas combined cycle unit. Units that incorporate carbon capture and storage would be exempted from the performance standard until 2025. This regulation was announced to be implemented in mid-2015. It is expected that such emission standards would make coal-fired generation prohibitively expensive for new additions in the next decade.
Figure 2-3: Geographic location of coal resources
Alberta is providing funding to advance clean coal and carbon capture and storage (CCS). Two projects described below have received approval for funding to support their development. Of $2 billion allocated by the province for CCS projects, $721 million has been provided to these projects.

Project Pioneer will be a CCS project that will be retrofitted onto the Keephills 3 coal-fired power plant that is being developed east of Edmonton. The project will capture and store up to one million tonnes of CO\(_2\) per year using Alstom’s proprietary chilled ammonia process. The project is expected to be operational in 2015. The captured CO\(_2\) will either be injected about 2,700 metres below the surface for permanent storage or used in enhanced oil recovery. This project is also in partnership with the Global CCS Institute and the information gathered from this project will be shared around the world.

A second project approved for funding is the in-situ coal gasification (ISCG) Swan Hills ISCG Power Project. This technology involves the controlled combustion of deeply buried coal to produce synthetic gas (syngas). The produced syngas can be used as fuel similar to natural gas for power generation. The Swan Hills ISCG Power Project has been proposed for northern Alberta near Swan Hills and would create syngas from deep unminable coal. The project would also capture CO\(_2\) that could then be used for enhanced oil recovery. The syngas created would be used to power a 300 MW combined cycle facility, providing a stable form of baseload power to the province. The project developer has identified additional coal resources in the province that could be developed with this technology. A second 300 MW opportunity has been identified as phase two.

Source: Swan Hills Synfuels Website

- **300 MW Clean Electricity Generation**
- **1.3 million tonnes per year CO\(_2\) sequestration**
Natural gas
Gas-fired generation plays an important role in the Alberta electricity market by providing reliable baseload, flexible mid range, and peaking capacity. Currently there is 5,371 MW of gas-fired generation in Alberta. This capacity includes simple cycle, combined cycle and cogeneration plants and represents 41 per cent of the total installed capacity. Many of the gas plants in Alberta have been built in the last ten years and the growth of gas-fired generation is expected to continue. Gas-fired generation can be located in most areas of the province as pipeline infrastructure makes the fuel source flexible.

Simple cycle gas turbines
Simple cycle gas turbines’ short start-up time and ability to ramp up and down rapidly make them well suited for providing peaking capacity, operating reserves, and for wind following. An example of a peaking turbine in Alberta is the GE LM6000, which can produce approximately 45 MW of electricity. Since 2008 there have been four peaking facilities added in Alberta. Three of these new facilities are located in northern Alberta and include the 50 MW Valleyview 2 unit in northwest Alberta, the 250 MW Clover Bar facility within Edmonton, and the 93 MW Northern Prairie Power Project unit in the County of Grande Prairie No. 1. The 120 MW Crossfield Energy Centre has also recently been energized and is located just north of Calgary.

Combined cycle plants
Combined cycle plants utilize a gas turbine’s waste heat to create steam that generates electricity in a steam turbine, achieving higher efficiencies than other technologies such as pulverized coal and simple cycle turbines. This higher level of efficiency makes combined cycle plants competitive in mid-range, and in some instances, baseload operation. The higher efficiency, together with the higher proportion of hydrogen in natural gas compared to coal, results in CO₂ emissions of 0.4 tonne/MWh, which is substantially below a supercritical pulverized coal plant’s emissions of 0.9 tonne/MWh. The 300 MW Calgary Energy Centre located on the northern boundary of Calgary is an example of a combined cycle plant in Alberta. Given the expectations for greenhouse gas (GHG) restrictions on coal-fired generation and stable natural gas prices, a large amount of combined cycle capacity is being proposed in Alberta. Two large combined cycle projects that have been proposed are the ENMAX Shepard Energy Centre and the TransAlta Sundance 7. These two projects would have enough capacity to replace four large coal units. In addition to these projects, there is the potential for further combined cycle plant additions given less GHG cost risk, guaranteed capital costs and low natural gas prices.

Cogeneration
Cogeneration plants use energy efficiently by producing electricity in addition to generating heat or steam required for an industrial process. Cogeneration is well suited for industrial processes in Alberta such as oilsands extraction and upgrading. These processes require large amounts of heat and steam, along with electricity. Many oilsands producers such as Suncor, Syncrude, and CNRL use cogeneration in their processes. The addition of cogeneration units in northeast Alberta is expected to continue as the development of the oilsands continues. In May 2010, the Oilsands Developers Group released a survey on the use of cogeneration in the Alberta oilsands developments. The survey estimates 1,500 MW of cogeneration additions would be developed by 2019 in the most probable case. A majority of this capacity, about 59 per cent, is expected to be developed with in-situ projects.
Wind power

There are 14 transmission connected wind farms operating in Alberta with a total capacity of 777 MW. This represents six per cent of the installed capacity. A majority of the wind farms are located in southern Alberta around the Pincher Creek area. In late 2010, the 82 MW Ghost Pine wind farm was completed which is located in central Alberta east of Red Deer.

Alberta wind resources are attractive for development. There are three areas where wind speeds indicate the attractive development areas for wind facilities. These locations are mainly in the southern and central regions of the province, and a smaller area in the northwest. The southern region of Alberta has seen substantial wind development in the last two years with the addition of three new wind farms totalling almost 200 MW of capacity. The newly developed wind farms include the Ardenville, Blue Trail and Summerview 2 facilities. The Central region of Alberta saw the Ghost Pine wind facility commence operation at the end 2010. Both the south and central areas of the province are expected to see continued wind development as wind resources are regarded as excellent. The northwest area of the province also has wind resources and there exists the potential for development in the area. As of April 30, 2011 there are over 40 wind projects totalling over 6,500 MW in the interconnection queue. Wind projects have continued to move forward in the last two years securing regulatory approvals and financing. Approximately 1,600 MW of wind projects have either applied to or received Alberta Utilities Commission (AUC) power plant approval. This progress highlights the strong interest in the development of wind resources in Alberta.

The economics of wind energy in Alberta is dependent on the Alberta pool price and clean energy incentives. The Canadian government has provided financial incentives for power produced from renewable fuel sources, including wind power. The federal ecoENERGY for Renewable Power Program provided an incentive of one cent per kilowatt hour (kWh) for up to 10 years for renewable projects built between April 1, 2007 and March 31, 2011. Renewable energy credits and credits under the Alberta Specified Gas Emitters Regulation are another way for wind projects to support the development.

With the interest of wind development in Alberta, the AESO has continued to collaborate with industry to facilitate wind development. Recently, technical standards have been developed for the connection of wind to the transmission grid, a first in North America. The AESO has also completed a sophisticated wind forecasting study using international vendors and a resulting six day ahead wind power forecast is now published for the use of all interested stakeholders.

The AESO connection queue is updated monthly to reflect the progress projects are making. For the most up to date queue follow the path www.aeso.ca > Customer Connections > Connection Queue
Figure 2-4: Geographic location of wind resources
**Nuclear**

Globally, there are approximately 435 nuclear reactors currently in operation with a total capacity of 370 GW and another 55 reactors under construction. Within Canada, there are 17 nuclear reactors, all of which are located in eastern parts of Canada. Nuclear power provides the benefits of supplying large amounts of baseload energy while helping to address the increased pressure to reduce GHG emissions.

An expert panel appointed by the Government of Alberta released a report on nuclear energy in March 2009. Issues such as environment, health and safety, waste management, and social issues and concerns were examined. As a result of the report and consultation, the Government of Alberta decided to maintain its existing policy where power generation options are proposed by the private sector in the province, and any nuclear power proposal would be considered on a case-by-case basis.

Alberta has seen limited interest in nuclear development. In 2008, Bruce Power Alberta filed an application with the Canadian Nuclear Safety Commission to prepare a site in the Peace River area near Lac Cardinal. This application would have been western Canada’s first nuclear power plant and could have produced up to 4,000 MW. The application was later withdrawn in January 2009 and no new applications have been submitted.

In addition to current nuclear facilities, small modular nuclear reactors could be developed. These units could deliver relatively small amounts of energy and be small enough for transportation by ship, truck, or rail. An example of this technology is the Hyperion Power Module (HPM). The HPM utilizes the energy of low-enriched uranium fuel. Each unit produces 27 MW of electricity when connected to a steam turbine, or 70 MW of thermal energy, for a period of seven to 10 years. After five years, the HPM would be removed and refuelled at the original factory. This technology is currently in early regulatory stages and is not expected to be available in the next ten years.

**Biomass**

Alberta currently has five biomass power facilities with a total capacity of 180 MW. Biomass fuel resources are available in Alberta from the forestry industry (industrial and commercial wood residues) and the agricultural sector (crop and livestock waste). Power production from biomass power facilities typically runs as a baseload generator. Generation from biomass is generally restricted to locations at the source of the fuel due to transportation costs.

There have been a number of biomass projects proposed throughout the province. The Lethbridge biomass project will be capable of treating 10,000 metric tonnes of organic resources from livestock operations and the ag-related food industry annually. The facility will be able to produce three MW of power. This project has received $8.2 million in provincial funding. Mustus Energy Limited has proposed a 35 MW biomass power plant that would produce electricity from waste wood and Weyerhaeuser is replacing an existing turbine with a more efficient unit.

The potential for new biomass generation is expected to be from relatively small installations and overall capacity is not expected to be significant. The costs for biomass power plants are expected to be high and would not be economic compared to other technologies. Government funding for this type of renewable energy is making a number of projects viable and continued funding would increase the capacity installed in Alberta.
Figure 2-5: Geographic location of forestry resources
Other renewables

Electricity from renewable resources is becoming increasingly important as the effort to improve environmental performance continues to grow. Technologies such as solar, geothermal and waste heat are all technologies that could contribute to Alberta’s generation mix. These technologies are still developing and the costs and efficiencies are likely to improve over time. Government policies at both the federal and provincial levels have provided benefits that will help with the development and integration of these renewable energy sources. The following technologies will continue to be tracked and incorporated into system plans as required.

Solar

Solar technologies available for energy production can be separated into two technologies. The first is photovoltaic (PV) panels that produce power directly from the sun. The second is concentrating solar power that reflects solar rays to a single point and the resulting heat is used to create electricity.

There are two large initiatives in Alberta that are focusing on solar technologies. The City of Medicine Hat has received funding for a one-MW demonstration concentrating solar thermal power project. This project would use a solar-powered steam generation system and would be integrated with an existing natural gas power plant. Commercial operation is expected in August 2012 and the final outcome of the demonstration project is expected in late 2013. ENMAX has received $14.5 million in funding from the Climate Change and Emissions Management Corporation for home generation using solar panels and micro wind turbines. This project began roll out to consumers in 2011.

It is expected that solar technologies will be installed as a result of microgeneration policies and other government incentives. These policies would incent small-scale installations, and it is not expected to be large capacity additions. While Alberta receives a large amount of sunlight each year, the intensity of the sunlight is low and results in a reduced amount of expected solar capacity.
**Geothermal**

Geothermal power generation uses heat from within the Earth to power a steam turbine. This generation technology would provide reliable baseload energy to the Alberta system. The Canadian Geothermal Energy Association has estimated that Alberta and the N.W.T. have the combined potential of 500 MW to 1,000 MW of geothermal energy. Currently, work is being done on a project northwest of Edmonton that will produce geothermal power from hot water within mature oil wells. If this project proceeds it will be able to produce two MW of electricity.

The geothermal heat resources in Alberta are relatively small compared to other areas in Canada. It is likely that developers of large-scale geothermal projects would choose provinces such as British Columbia and the Yukon for development rather than Alberta. These provinces have hotter and shallower heat resources than Alberta. Development of geothermal projects in these provinces could serve as a barometer for potential development in Alberta. There does exist the potential for geothermal energy to be extracted from mature oil and gas wells. These small-scale projects will be monitored.

**Waste heat**

Heat from industrial processes can be captured to create steam, which can power a turbine to create electricity. Given Alberta’s industrial economy, small installations of this type of power generation may arise as overall energy efficiency becomes increasingly important. Currently Alberta has a small amount of waste-heat generation on the transmission system. An example of a current installation is the Cancarb Waste Heat Recovery Power Plant in the City of Medicine Hat. This plant has a capacity of 26 MW. Another potential project is NRGreen Power’s proposition to construct the Windfall Power Generating Station that will use waste-heat to create electricity. The project will be able to produce approximately 16 MW of power from two waste-heat generating units.

Interest in development of waste-heat applications has been seen through projects seeking regulatory approvals, implying the technology will likely see modest development in the province. The use of waste-heat as a source of electricity will be limited to small-scale installations scattered throughout the province at locations such as pipeline compressors. As the units are of small capacity, the impact on the transmission system will be limited.
Storage
Energy storage can play an important role in reducing swings in demand and generation. A typical daily load shape of low demand during the night and high demand during the day can partially be offset with energy storage by storing energy during the evening, increasing demand, and releasing the energy during the day. Likewise, with variable generation such as wind, during high electricity production times from wind, energy storage units could use the surplus power to store energy and release this energy when wind electricity production is low.

Current energy storage technologies include large-scale storage such as pumped hydro storage and compressed energy storage, to small-scale storage such as batteries and flywheels. With extensive underground reservoirs and aquifers in Alberta, compressed air energy storage could potentially be used within the province. This technology stores compressed air underground, and then uses the compressed air in a turbine at a later time to increase the efficiency of electricity production. New developments in this technology are looking at above ground methods of storing the compressed air.

The energy storage project currently under development in Alberta is a very small pilot project, and it is not expected that any substantial (greater than 10 MW) energy storage project will be developed in Alberta in the next ten years.

3.0 COMPARATIVE COSTS OF GENERATION TECHNOLOGY OPTIONS

Each of the generation technologies discussed in the previous section has unique financial and technical characteristics. When developing the generation baseline and scenarios, the relative cost of the different generation technologies is considered. This section estimates the comparative cost of several generation technologies, an exercise that is used to consider which technologies will be attractive to developers and is not a reflection of the overall merits of any specific generation project.

The levelized unit electricity cost (LUEC) is used to assess the relative economic merits of different generation technologies. The comparative cost represented by the LUEC is the constant electricity price required to cover all costs, including a specified rate of return, over the entire life of the project. Specifically, the LUEC is derived by using a discounted cashflow approach, which sets the present worth of revenue equal to the present worth of expenses, determining the constant price required to cover all expenses. The costs included in the calculation are capital, financing, operating and maintenance (O&M), fuel, emission, and taxes, giving a busbar cost that excludes transmission related charges.

The assumptions used in the calculation of the LUEC are Alberta-specific based on public information adjusted through consultation with generation developers as well as industry stakeholders.
Selection of technology options and their characteristics

The LUEC calculation is undertaken for generation technologies of a substantial size (greater than 20 MW) that are likely to be developed in Alberta in the next 10 years. The technologies examined in the LUEC analysis include:

- Simple cycle gas turbine with a net capacity of 45 MW and a capacity factor of 20 per cent.
- Combined cycle gas-fired plant with a net capacity of 500 MW and a capacity factor of 60 per cent.
- High efficiency cogeneration plant (GE 7EA) with a net capacity of 85 MW and a capacity factor of 90 per cent.
- Wind power generation with a net capacity of 150 MW and a capacity factor of 35 per cent.
- Supercritical pulverized coal (SCPC) plant without carbon capture at a brownfield site. It is assumed to be similar to the Keephills Unit 3, which has a net capacity of 450 MW. Its capacity factor is assumed to be 92 per cent.

The characteristics of the technologies assessed are listed in Table 1.

<table>
<thead>
<tr>
<th>Technology Description</th>
<th>Simple cycle</th>
<th>Combined cycle</th>
<th>Cogen²</th>
<th>Wind</th>
<th>SCPC without carbon capture</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net power production (MW)</td>
<td>45</td>
<td>300</td>
<td>85</td>
<td>150</td>
<td>450</td>
</tr>
<tr>
<td>Heat rate (GJ/MWh)</td>
<td>9.8</td>
<td>7.1</td>
<td>12.6</td>
<td>0</td>
<td>9.4</td>
</tr>
<tr>
<td>Average capacity factor</td>
<td>20%</td>
<td>60%</td>
<td>90%</td>
<td>35%</td>
<td>92%</td>
</tr>
<tr>
<td>Emission intensity (t/MWh)</td>
<td>0.5</td>
<td>0.37</td>
<td>0.241</td>
<td>0</td>
<td>0.9</td>
</tr>
<tr>
<td>Project life (years)</td>
<td>25</td>
<td>30</td>
<td>30</td>
<td>30</td>
<td>35</td>
</tr>
</tbody>
</table>

Other technologies were not included in the LUEC estimation either due to data limitations or the project specific nature of costs.

² In the case of cogeneration, the parameters presented are for the whole facility. All costs are included in the calculation and a revenue stream for steam production is subtracted from the LUEC. The heat rate is based on total gas consumption of the facility and the net electricity output, it does not represent the market heat rate of cogeneration which accounts for the gas used in steam production. The emission intensity is based on the total emissions of the facility over the total electrical and thermal output.
Cost assumptions

The following section delineates the cost components of the levelized cost and summarizes the inputs and assumptions used. All costs are expressed in 2010 Canadian dollars and assume a 2010 construction start date for all technologies.

Capital cost and financing costs

The capital cost is the initial investment necessary to plan, permit, construct and start up a plant. Table 2 lists the 2010 overnight capital cost and construction time for the technologies. Overnight capital cost does not include the financing cost incurred during construction; rather, it is the cost of a construction project if no interest was incurred during construction, as if the project was completed overnight. The interest charges accumulated during construction are accounted for separately within the LUEC calculation.

Table 3-2: Generation technology overnight capital costs and construction time

<table>
<thead>
<tr>
<th></th>
<th>Simple cycle</th>
<th>Combined cycle</th>
<th>Cogen</th>
<th>Wind</th>
<th>SCPC without carbon capture</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overnight capital cost (2010 $/kW)</td>
<td>$1,050</td>
<td>$1,435</td>
<td>$1,800</td>
<td>$2,500</td>
<td>$3,500</td>
</tr>
<tr>
<td>Construction (years)</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>2</td>
<td>4</td>
</tr>
</tbody>
</table>

For the purposes of cost comparison, common assumptions are used for financing costs, recognizing that each project will have unique ownership structures and financial circumstances. It is assumed that all plants are financed 60 per cent by debt and 40 per cent by equity. The debt ratio is held constant during the construction year(s). It is assumed that the projects require a seven per cent rate of return on debt and a 15 per cent rate of return on equity. With a tax rate of 28 per cent, this implies a weighted average cost of capital (WACC) of nine per cent. The inflation rate used is two per cent over the lifetime of the project. During the construction, the capital cost escalates at two per cent each year.
**Operation and maintenance costs**

O&M costs for each of the technologies are shown in Table 3. Fixed O&M costs are reported in 2010 dollars per net kW of capacity per year. Variable O&M costs are reported in 2010 dollars per MWh. The operating capital required for technologies periodically throughout their lifetime is included in the fixed O&M costs. For all technologies, O&M costs are projected to remain constant, in constant dollars, during the entire economic lifetime of the plant.

<table>
<thead>
<tr>
<th></th>
<th>Simple cycle</th>
<th>Combined cycle</th>
<th>Cogen</th>
<th>Wind</th>
<th>SCPC without carbon capture</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed O&amp;M (2010 $/kW-yr)</td>
<td>12.60</td>
<td>13.70</td>
<td>13.70</td>
<td>41.00</td>
<td>31.50</td>
</tr>
<tr>
<td>Variable O&amp;M (2010 $/MWh)</td>
<td>4.20</td>
<td>4.20</td>
<td>4.20</td>
<td>2.00</td>
<td>6.30</td>
</tr>
</tbody>
</table>

**Fuel costs**

Fuel costs include all fuel supply costs at the power plant. Natural gas and coal are the only purchased fuels considered in the technologies investigated in this section. The AECO-C gas forecast (see Figure 3-6) for the period 2010 to 2020 prepared in March 2011 by Sproule Associates Limited is used to calculate the cost of natural gas for the combined cycle, cogeneration and simple cycle gas turbine plants. After 2020, a constant escalation factor of two per cent per year is used.

**Table 3-3: Generation technology operation and maintenance costs**

**Figure 3-6: Alberta AECO-C natural gas price forecast**

Source: Sproule Associates Limited
In the case of cogeneration, steam produced is considered to be sold as a source of revenue and is deducted, for simplicity, from the fuel cost. The price of steam is estimated to be 60 per cent of the cost of producing steam from a natural gas-fired once through steam generator, averaging $5.4 per gigajoule (GJ). The actual cost of steam from specific cogeneration units is determined through contractual agreements, and has an impact on the cost of electricity from the cogeneration plant.

The price for coal in Alberta for power generation is generally stipulated under long-term, cost of service arrangements and is relatively stable. Based on the available public information and discussions with generation developers, coal prices at brownfield sites are assumed to remain constant in real terms at an estimated $1.5/GJ.

**Greenhouse gas offset costs/credits**

The environmental costs and credits related to GHG emission constraints will affect the cost of different generation technologies in different ways. Non-emitting power plants could gain an economic advantage over emitting power plants depending on the level of the constraints.

The current cost of emitting greenhouse gases in Alberta under the Specified Gas Emitters Regulation is at most $15/tonne of CO$_2$e for 12 per cent of output for large emitters. This amounts to an effective current CO$_2$e price of $1.80/tonne.\(^3\) In the future, the costs of emitting GHG may increase as Alberta raises the cost of compliance or increases the fraction of emissions covered under the regulation. At this time, no schedule has been announced for any increases to the effective GHG price in Alberta, and the potential for national GHG prices is also uncertain.

For the purposes of estimating the LUEC of the various generation technologies, a set of assumptions on the cost of emitting and the fraction of emissions that need to be accounted for is defined and presented in Figure 3-1. The plot on the top shows the projected compliance costs for emitting GHG as well as the fraction of CO$_2$e emissions assumed to be covered in the baseline outlook. The bottom plot shows the effective GHG price (after accounting for both the GHG compliance cost and the fraction covered), which is used in the LUEC estimation.

The AESO has assumed the cost per tonne of GHG will remain at $15/tonne of CO$_2$e until 2014, after which the price begins to rise. It was also assumed that the fraction of emissions covered under the regulation remains at 12 per cent until 2014, after which the portion of emissions covered increased by an additional two per cent per year until the unit reaches an emission intensity of 0.2 t/MWh.

---

\(^3\) On average the overall GHG price may be a bit lower if lower-cost emissions reductions or offsets are available. Specifically, emitters may comply with the regulation by reducing per-unit GHG output by 12 per cent, procuring offsets from emitters that reduced per-unit GHG output by more than 12 per cent, purchasing Alberta-based GHG offsets, or make a technology fund contribution of $15/tonne.
The value of GHG credits for renewable power in Alberta is continually changing; the products that can be sold and the markets and prices at which the products are sold are still evolving with policy development in various jurisdiction. To provide a transparent view of the value of these credits to a wind project's LUEC, revenue from the ‘green’ attributes of a wind project have been excluded from the LUEC calculation and are addressed instead as a sensitivity of wind generation costs at the end of this section.
**Summary of levelized unit electricity costs**

The LUECs are calculated in constant dollars (uninflated) by cost components: capital cost, O&M cost, fuel cost, GHG offset cost and taxes. As shown in Figure 3-2, the LUECs for cogeneration, SCPC, and combined cycle plants are similar, within the $70-$80/MWh range. The LUEC estimate of $99/MWh for wind plants excludes any potential revenue received through the sale of green attributes or emission credits. The potential revenue from offsets or credits will make wind power more cost effective. For simple cycle gas turbines, the LUEC is higher than other generation options as they are generally peaking units with low capacity factors that run only during high priced hours. In this case a capacity factor of 20 per cent was assumed.

**Figure 3-2: Comparative levelized generation costs**

![Figure 3-2: Comparative levelized generation costs](image)

There is uncertainty associated with the inputs into the LUEC calculation, specifically natural gas prices, capital costs, future climate change policy and its compliance costs/credits, and capacity factors. To quantify the uncertainty of these assumptions on the LUEC of different generation technologies sensitivity analysis was undertaken. The following variations were considered: a -20%/+50% variation from the natural gas forecast, a -75%/+100% variation for the GHG cost estimates, a -20%/+20% capital cost variation for SCPC, and a -5%/+5% variation in the wind capacity factor. Also a potential $5-$10/MWh carbon credit (constant dollar) for wind power is also included. The cost ranges under these sensitivities for different technologies are presented in Figure 3-3. The sensitivity bands on the LUECs for cogeneration, combined cycle and SCPC cover a similar range.
The cogeneration unit, under the defined configuration, has the lowest LUEC due to its high efficiency, low emission costs and assumed steam revenue. However the decision to develop cogeneration within an industrial process is also dependent on factors other than the cost of generating electricity. These include the availability of a steam host, the increased operational complexity added to the industrial site, increased capital costs for the operation, increased natural gas consumption for the operation and finalizing contractual agreements.

A high portion of the combined cycle levelized generation cost is the fuel cost. As future natural gas prices are forecast to be moderate and stable, and climate change policy remains uncertain, combined cycle generation is an appealing development option. The comparative levelized generation costs leads to the conclusion that combined cycle generation will become the dominant form of baseload additions in the short term. While climate change policy evolves, clean coal technology advances and long lead time projects such as hydro and nuclear can develop.

![Figure 3-3: Sensitivity analysis of levelized generation costs](image-url)
The cost advantage of coal-fired power is reduced as natural gas prices decline and carbon costs rise. With current natural gas price expectations and the uncertainty of future climate change policy, the attractiveness of developing new coal-fired generation becomes challenged. Future restrictions on emissions from coal-fired generation have been announced but remain to be finalized. If coal plants are able to purchase offsets to meet their requirements it leads to an increased cost, if they are not able to purchase offsets technologies to reduce or capture emissions would be required. These technologies currently face technical challenges and substantial cost. The incremental cost to capture emissions from coal plants varies according to efficiency losses. Estimates peg adding carbon capture to a coal plant to raise the cost of producing electricity by about 30 per cent to 55 per cent, with considerable uncertainty. The commercialization development of clean coal power plants is progressing with the development of a number of pilot projects worldwide, but economic commercialization depends on technology development, cost reduction and an aggressive strong price signal for carbon emissions.

Wind power relies on environmental initiatives to become attractive. As more wind power is added to the system, fast ramping simple cycle gas turbines will also be an appealing development option as they are a strong candidate to provide ancillary services and to capture the scarcity pricing.

Overall, the LUEC provides an indication of the relative costs of the different generation technologies. As the cost for developing cogeneration, combined cycle and SCPC are within a similar range, other drivers will determine how much of each generation type is developed. Specifically for cogeneration, the propensity of industrial developers to include cogeneration within their projects will determine the amount of cogeneration to be added to the system. The uncertainty surrounding future emission requirements for coal generation will limit its development in the near term until policy is firmly defined. This leaves combined cycle generation as the dominant form of baseload additions in the short term, along with the addition of wind, which will be driven heavily by the value of its environmental attributes and simple cycle, which fills the need for fast ramping peaking capacity.
4.0 GENERATION Baseline AND SCENARIOS

To provide an outlook of the future transmission system required in Alberta, information about the size, location and type of future generation that may develop in the province is required. Generation development is a competitive business, which makes forecasting the timing and location of new generation challenging. In recognition of this challenge, the AESO created a baseline forecast, and a corresponding range of generation scenarios against which the transmission system is tested to identify where system reinforcement could be required to meet future need. The generation baseline and scenarios are used as input to the LTP to ensure the transmission system is adequately planned to provide reliable power to Albertans and to facilitate the competitive electricity market.

The following section discusses the generation baseline and scenarios as well as the methodology and rationale used in their development.

Generation reserve margin

Since generation of electricity is a competitive business in Alberta, the amount of generation developed in the province is determined by market participants based on market signals. Of note, generation developers in Alberta take on 100 per cent of the risk in building new projects. There is no regulated rate of return on power generation in Alberta as exists in many other jurisdictions in Canada. Also, there is no adequacy reserve margin requirement defined by an authoritative body in Alberta.

The AESO expects that the market will continue to send the appropriate signals to generation developers, motivating them to develop additional supply in the province as it is required. The AESO uses a reserve margin as a proxy for the amount of generation added to the system due to market signals. An effective reserve margin of 10 per cent is considered in the development of the generation forecasts, and is tested to ensure it is appropriate for the purposes of estimating the generation capacity that will be installed to meet total Alberta peak load. The margin assumption is tested to ensure the market signals support the development of the generation in the forecast, as well as to ensure that the generation in the forecasts adequately meets load.

The term effective reserve margin is an estimation of the amount of generation that will be installed above peak load through the competitive market because of market signals. It is determined by taking the maximum continuous rating of the existing generation and derating wind and hydro capacity. The derates applied to wind and hydro capacity to calculate the reserve margin remain unchanged from those used in the AESO’s 2009 LTP. The derate to wind and hydro to estimate their effective capacity is an estimation of the market’s interpretation of the wind and hydro’s impact on market signals. Wind and irrigation hydro are derated to 20 per cent of total capacity, legacy hydro is derated to 67 per cent of total capacity and new hydro is derated to 50 per cent of capacity. Intertie capacity is excluded from the effective reserve margin.
REQUIRED GENERATION ADDITIONS

The Future Demand and Energy Outlook (2009-2029) forecast with the 10 per cent effective reserve margin, as presented in Figure 4-1, provides an estimate of the expected effective generation capacity that will be installed over the next 20 years. Based on the effective reserve margin and forecast load, effective generation capacity in Alberta is expected to increase to 17,000 MW by 2020 and 20,500 MW by 2029, as shown in Figure 4-1. These values are compared to existing effective generation capacity to determine the amount of generation additions expected for Alberta. The existing effective generation capacity excludes intertie capacity and incorporates future retirements and derates to intermittent generation.

Expectations on future retirements of existing generation in the baseline generation scenario is predominantly driven by the announcement made by Environment Canada on June 23, 2010 regarding the future of coal-fired electricity generation in Canada. The proposal would essentially set an emission performance standard for coal-fired generation commissioned after 2015 or existing plants that have either met a 45-year life or have met their Power Purchase Arrangement (PPA) expiration, whichever is later. This proposed policy sets the expectation that coal generation will retire before or once it reaches a 45-year life as meeting the performance standard would be prohibitively expensive. These expectations imply that over 1,000 MW of generation will retire prior to 2020, and an additional 3,000 MW will retire between 2021 and 2029. Consideration was given to the timing of the 45-year life on each plant, the expiration of each plant’s PPA, and the opportunity cost of foregoing the Balancing Pool covering decommissioning expenses if retirement was postponed one year beyond the expiration of the PPA. The assumed retirements is a substantial difference from the 2009 LTP, with nearly 700 MW more retirements by 2020.

Retirements of the generating units in the table below are included in determining the effective generation capacity in future years for the baseline scenario.

Table 4-1: Assumed unit retirements in baseline generation scenarios

<table>
<thead>
<tr>
<th>By 2020</th>
<th>MW</th>
<th>By 2029</th>
<th>MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rainbow 1,2,3</td>
<td>90</td>
<td>Sundance 3,4,5,6</td>
<td>1,575</td>
</tr>
<tr>
<td>Sturgeon 1,2</td>
<td>18</td>
<td>Battle River 5</td>
<td>389</td>
</tr>
<tr>
<td>Sundance 1,2</td>
<td>576</td>
<td>Sheerness 1,2</td>
<td>780</td>
</tr>
<tr>
<td>H.R. Milner</td>
<td>144</td>
<td>Keephills 1</td>
<td>390</td>
</tr>
<tr>
<td>Battle River 3,4</td>
<td>308</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
The difference between the expected effective generation capacity and the existing effective generation capacity equals the amount of generation that will be added to the market. Based on the information shown in Figure 4-1, by 2020 the amount of effective generation additions required is expected to be 6,000 MW and by 2029 it is expected to be 13,000 MW. Over the next 20 years the effective generation capacity is expected to almost double from what it was in 2010.
Baseline generation scenario

Based on the expectation that 13,000 MW of new effective generation capacity will be added to the system in the next 20 years the AESO created a baseline generation scenario describing the type and location of generation additions expected over the next 20 years. The baseline generation scenario represents a reasonable, most likely, generation scenario which the transmission system can be tested to identify where reinforcement is required.

The baseline generation scenario is premised on a set of assumptions that lead to the overall expectation that generation additions will come mainly from gas-fired capacity (combined cycle, cogeneration and simple cycle) and additional wind capacity. These assumptions, which currently represent the most likely outlook are:

- Climate change policy continues to be a topic of discussion and by 2018 there is certainty behind the policy, compliance costs are roughly $30/tonne by 2020.
- Continued expectations of a policy that requires coal to physically mitigate its GHG emissions leads to minimal SCPC coal development in Alberta.
- Existing coal-fired generation retires on a schedule that follows the proposed federal policy.
- Natural gas supplies remain healthy and similarly the long-term outlook for natural gas prices remain moderate and stable.
- Uncertainty for green revenue for wind continues, keeping the economics of new wind generation only moderately healthy.
- Market developments and subsidies for other renewables and low emission power sources continue to waver until 2018 when there is some certainty leading to new developments post-2020.

<table>
<thead>
<tr>
<th>Table 4-2: Main baseline generation scenario assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Greenhouse gas costs</td>
</tr>
<tr>
<td>Natural gas costs</td>
</tr>
<tr>
<td>Clean coal technology</td>
</tr>
<tr>
<td>Coal retirements</td>
</tr>
<tr>
<td>Economics of wind</td>
</tr>
<tr>
<td>Location of gas additions</td>
</tr>
<tr>
<td><em>(combined cycle/simple cycle)</em></td>
</tr>
<tr>
<td>Cogeneration</td>
</tr>
<tr>
<td>Other renewables, low emission, distributed generation</td>
</tr>
</tbody>
</table>

This set of assumptions will impact each technology and fuel source differently. The details behind the expected development for each technology are given on the following pages.
Gas-fired generation

Gas-fired generation is an attractive option at this point in time due to the expectation of stable natural gas prices in the future, relatively lower GHG risk, and proven technologies with competitive capital costs that can be developed in less than five years.

Combined cycle natural gas generation is attractive from cost (natural gas, capital cost) and certainty (technology, GHG cost) perspectives for new baseload capacity. Alberta’s expanding industrial sector’s increased need for steam and heat makes highly efficient, low cost cogeneration an option for future growth.

Finally, additional gas-fired peaking capacity is attractive for maintaining system balance and integrating variable generation into the system.

Combined cycle

Given the relative economics of generation, which show combined cycle gas-fired generation currently to be one of the least cost options per megawatt of installed capacity, a large portion of additions are expected to come from this form of generation. With the market expectation of stable natural gas prices in the future, relatively lower GHG cost risk than coal, the need for baseload generation to meet load growth and the need to replace retiring coal generation, combined cycle gas-fired generation is expected to remain attractive while longer term options, such as hydro, nuclear and clean coal develop.

The location of gas-fired generation is more flexible than other resources that are dependent on fuel source location such as wind, coal and hydro. Pipeline access, availability of water, transmission access and an accepting community are important factors in siting gas-fired generation. Planned projects in southern Alberta and the possibility of repowering existing coal sites provide insights into the possible location of future natural gas plants. To account for this uncertainty, a sensitivity is considered in the baseline generation assumptions to test the development of most combined cycle and simple cycle generation in the south and north regions of the province.
Cogeneration
The development of additional cogeneration in Alberta, beyond the nearly 3,000 MW of capacity that exists today, will be largely driven by expansions in the oilsands industry. The AESO forecasts additional extraction and upgrading capacity to be added over the next 10 to 20 years. The use of cogeneration in oilsands projects to be developed was evaluated, and a forecast of cogeneration additions that corresponds to the oilsands forecasts used in the load forecast was created. The forecast of cogeneration additions assumes that the industry as a whole will continue to add cogeneration capacity to a level that is consistent with past behaviour. The cogeneration forecast in the baseline scenario aligns with a survey of oilsands developers presented in the *Oilsands Co-generation Report 2010* by the Oilsands Developer Group. There is uncertainty behind this forecast, which is further addressed in the test generation scenarios.

Simple cycle
Simple cycle generation has very flexible operation allowing it to respond quickly to the needs of the system. The amount and timing of simple cycle development is driven by scarcity prices in the market and the future value of its flexibility in maintaining system balance. Its location is flexible and therefore uncertain; however, generally, simple cycle generation additions are small in capacity, affecting regional transmission more than bulk transmission.
Coal

The June 2010 announcement on coal-fired emission standards sets the expectation that coal-fired generation will be prohibitively expensive for new additions in the short to mid-term. Given the anticipated environmental requirements for new coal plants to reduce emissions to a combined cycle level, the state of carbon capture technology and the cost of carbon capture and storage, beyond the Keephills 3 plant, a limited number of new conventional coal plants are expected in Alberta for the next ten years. Instead, gas-fired generation is expected to be developed as discussed previously. This is a major difference from the 2009 Plan, which considered several conventional coal resources (Genesee 4, Keephills 4, H.R. Milner Expansion) to be viable generation options for development prior to 2020.

Since 2008, continued uncertainty surrounding environmental policy, and more recently the announcement from the federal government on emission requirements for new coal plants has delayed and deferred the future development of new coal projects in Alberta. Specifically, the withdrawal of Capital Power’s Genesee IGCC project from the Alberta Carbon Capture and Storage funding program and the slower than planned progress of the H.R. Milner Expansion and the Bow City Power Project send the signal that new coal developments in Alberta have been deferred.

Prior to 2020 a modest amount of new coal capacity will be added to Alberta’s system with the connection of Keephills 3, a supercritical pulverized coal plant currently under construction and slated for commissioning in 2011. The plant has potential for carbon capture and storage in 2015. This development, coupled with the potential for upgrades at existing plants, and the possibility of a demonstration combined cycle unit fired by syngas created through underground coal gasification, support this view.

Beyond 2020 it is expected that clean coal technologies will become commercially available as a result of extensive research and development funding worldwide, creating an option for developing Alberta’s abundant coal resource.
**Wind**

During 2008 and 2009 wind developers were aggressively prospecting projects in Alberta, causing the AESO's connection queue to dramatically grow from a few thousand megawatts of wind connection projects to over 12,000 MW. However, the attractiveness of other markets, changes to federal subsidies and offset credits, and stricter financing requirements have led to a decline in wind projects applying for connection. Wind resources are still strong in Alberta, however uncertainty remains surrounding the economics of wind generation and future revenue from ‘green attributes’. The baseline outlook for wind development matches the outlook from the previous Plan, and the high wind case remains a scenario the transmission system needs to accommodate.

Current research indicates that up to 1,600 MW of wind projects have received power plant approvals from the AUC, have applications before the AUC, or have purchased their turbines. Forecasting longer term wind development required an assessment of the economics of wind development. Overall, the result is a baseline forecast of wind capacity reaching a total installed capacity of 2,500 MW in Alberta by 2020. The forecast strikes a balance between the *Provincial Energy Strategy*’s direction to support the development of green energy (specifically wind) and recognition of the uncertainty surrounding the economics of wind generation in Alberta and the attractiveness of other jurisdictions.

Beyond 2020 it is expected that wind will continue to develop in Alberta. As climate change policy is defined, markets for green power become more sophisticated, the internal Alberta market grows and globally the integration of wind into the electrical systems is refined, more wind will be developed and accommodated in the Alberta market.

**Other renewable projects and new technologies**

There are numerous biomass, small hydro and waste heat projects proposed for the province. Policies and grants to promote these types of developments are likely to continue and be available in the future, helping the development of smaller (100 MW or less) renewable projects.

Additionally, there are various generation technologies developing, including batteries, solar, flywheels, small nuclear and geothermal. For the most part the pace at which these technologies become commercial and economic is dependent on future climate change policy and overall development of the electricity industry. Any game changing technologies are expected to come about post-2020.

In the baseline scenario a total of 290 MW of capacity, made up of ‘other renewables’ and ‘new technology’ is included prior to 2020, and an additional 700 MW post-2020. These projects are expected to be distributed across the province and have a minimal impact on long-term transmission development.

**Large projects**

Large hydro and nuclear developments have been proposed by developers in Alberta. However, the development (regulatory, financing, design and construction) process for these projects is likely to be over a decade in length. Therefore, these types of developments are included in the 2020-2029 portion of the generation forecast.
Baseline generation assumptions

Figure 4-2 below provides the detailed additions by type included in the baseline generation scenario.

Prior to 2020, the majority of generation additions are expected to come from gas-fired generation (combined cycle, cogeneration and simple cycle), and wind capacity. This baseline generation scenario was validated through market simulations to ensure the mix of generation meets load adequately and market signals would support the development of the generation mix.

With a large portion of future capacity being gas-fired, and with location being more flexible than other types of generation, two scenarios are considered: one where the majority of the gas-fired combined cycle and simple cycle additions are added only in northern Alberta and the other where these gas-fired additions are solely located in southern Alberta.

Figure 4-2: Current and baseline 2020 installed capacities by fuel type

<table>
<thead>
<tr>
<th>Current installed capacity</th>
<th>2020</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>44% Coal</td>
<td>29%</td>
</tr>
<tr>
<td></td>
<td>Coal</td>
</tr>
<tr>
<td>29% Cogen</td>
<td>23%</td>
</tr>
<tr>
<td></td>
<td>Cogen</td>
</tr>
<tr>
<td>7% Combined cycle</td>
<td>14%</td>
</tr>
<tr>
<td></td>
<td>Combined cycle</td>
</tr>
<tr>
<td>7% Hydro</td>
<td>5%</td>
</tr>
<tr>
<td></td>
<td>Hydro</td>
</tr>
<tr>
<td>6% Wind</td>
<td>13%</td>
</tr>
<tr>
<td></td>
<td>Wind</td>
</tr>
<tr>
<td>5% Simple cycle</td>
<td>11%</td>
</tr>
<tr>
<td></td>
<td>Simple cycle</td>
</tr>
<tr>
<td>2% Other</td>
<td>2%</td>
</tr>
<tr>
<td></td>
<td>Other</td>
</tr>
</tbody>
</table>

|                            |      |
| 29% Coal                   | 5,588 MW |
| 23% Cogen                  | 4,304 MW |
| 14% Combined cycle         | 2,762 MW |
| 5% Hydro                   | 981 MW |
| 13% Wind                   | 2,500 MW |
| 11% Simple cycle           | 2,088 MW |
| 2% Other                   | 395 MW |
Post-2020 it is expected that the economics of generation will evolve due to the impact of climate change policy, costs of GHG and technology development. Overall this may shift the emphasis from gas-fired additions to clean coal technology and long lead time projects like hydro and nuclear, which are included in the baseline generation scenario near the end of the 2020 decade. Climate change policy and related funding and research could also lead to the development and commercialization of new technologies.

The technologies that prove to be the front runners for North America and Alberta are still to be determined; however, 700 MW of capacity was included in the baseline scenarios post-2020 to account for new technologies such as geothermal, small nuclear, biomass, commercial combined heat and power, solar, and other distributed types of generation.

The finalized baseline post-2020 shows two options for study. Both cases have the same capacity additions, but outline different potential for location and fuel type useful in analyzing the system impact. The first baseline considers the addition of substantial clean coal capacity of 970 MW. The second baseline considers the alternative case of 1,000 MW of nuclear generation in the province. Both baselines include a potential for 1,500 MW of hydro development.

**Figure 4-3: Baseline 2029 generation scenarios installed capacities**
### Table 4-3: Details of baseline generation scenarios including additions by fuel type

<table>
<thead>
<tr>
<th></th>
<th>2020 Baseline</th>
<th>2020 Coal renaissance</th>
<th>2020 Nuclear develops</th>
</tr>
</thead>
<tbody>
<tr>
<td>Forecast Alberta winter peak demand (FC2009)</td>
<td>15,162</td>
<td>18,695</td>
<td>18,695</td>
</tr>
<tr>
<td>10% effective reserve margin</td>
<td>1,516</td>
<td>1,870</td>
<td>1,870</td>
</tr>
<tr>
<td>Effective generation capacity required to meet peak demand and reserve margin</td>
<td>16,678</td>
<td>20,565</td>
<td>20,565</td>
</tr>
<tr>
<td>Effective existing generation capacity as of mid 2010</td>
<td>11,901</td>
<td>11,901</td>
<td>11,901</td>
</tr>
<tr>
<td>Retirements to 2020</td>
<td>1,136</td>
<td>1,136</td>
<td>1,136</td>
</tr>
<tr>
<td>Retirements from 2021 to 2029</td>
<td>–</td>
<td>3,134</td>
<td>3,134</td>
</tr>
<tr>
<td>Net effective generating capacity after retirements</td>
<td>10,765</td>
<td>7,631</td>
<td>7,631</td>
</tr>
<tr>
<td>Total effective generating capacity required</td>
<td>5,913</td>
<td>12,934</td>
<td>12,934</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Additions by fuel type</th>
<th>To 2020</th>
<th>2021 to 2029</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>834</td>
<td>970</td>
</tr>
<tr>
<td>Cogeneration</td>
<td>1,687</td>
<td>865</td>
</tr>
<tr>
<td>Combined cycle</td>
<td>1,935</td>
<td>2,730</td>
</tr>
<tr>
<td>Simple cycle</td>
<td>779</td>
<td>603</td>
</tr>
<tr>
<td>Hydro</td>
<td>100</td>
<td>1,500</td>
</tr>
<tr>
<td>Nuclear</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td>290</td>
<td>700</td>
</tr>
<tr>
<td>Wind</td>
<td>1,864</td>
<td>2,000</td>
</tr>
<tr>
<td>Total additions from 2010 to 2020</td>
<td>7,489</td>
<td>7,489</td>
</tr>
<tr>
<td>Total effective additions 2010 to 2020</td>
<td>5,948</td>
<td>5,948</td>
</tr>
<tr>
<td>Total additions from 2021 to 2029</td>
<td>9,368</td>
<td>9,375</td>
</tr>
<tr>
<td>Total effective additions 2021 to 2029</td>
<td>7,018</td>
<td>7,025</td>
</tr>
<tr>
<td>Total effective generation capacity</td>
<td>16,713</td>
<td>20,597</td>
</tr>
<tr>
<td>Total installed capacity</td>
<td>19,098</td>
<td>25,332</td>
</tr>
</tbody>
</table>
Test scenarios

In addition to the baseline assumptions used for primary analysis, the AESO uses various generation scenarios and system stress tests to evaluate transmission requirements. In this additional analysis the AESO considers how the transmission system would need to develop should alternative generation patterns emerge. While loads are relatively immobile, generation development is geographically varied and has diverse impacts on the regional transmission system. As such three additional generation scenarios are developed and tested to ensure the transmission plan is flexible and robust enough to accommodate alternate development scenarios.

The table below describes the variation across the key assumptions that define the generation scenario development. The variation across the scenarios is largely driven by environmental policies and the resulting impacts on the various generation technologies.

Table 4-4: Test generation scenarios key assumptions

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Greenest (GSI)</th>
<th>Baseline/Cogen (GS2, 3, 4)</th>
<th>Business as usual (GSS)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Greenhouse gas costs</td>
<td>$40-50/t in 2020</td>
<td>$32/t in 2020</td>
<td>$15/t in 2020</td>
</tr>
<tr>
<td>Natural gas costs</td>
<td>High/moderate</td>
<td>Moderate</td>
<td>Moderate</td>
</tr>
<tr>
<td>Clean coal technology</td>
<td>Any new coal is clean coal; one project developed pre-2020</td>
<td>Any new coal is clean coal; developed post-2020</td>
<td>Any new coal is clean coal; developed post-2020</td>
</tr>
<tr>
<td>Coal retirements</td>
<td>Plants older than 45 years retire; some others retire earlier due to economics</td>
<td>All plants older than 45 years retired</td>
<td>All plants older than 45 years retired</td>
</tr>
<tr>
<td>Economics of wind</td>
<td>Strong (4,000 MW in 2020)</td>
<td>Moderate (2,500 MW in 2020)</td>
<td>Marginal (1,500 MW in 2020)</td>
</tr>
<tr>
<td>Gas additions (combined cycle/simple cycle)</td>
<td>Distributed</td>
<td>North/South</td>
<td>Distributed</td>
</tr>
<tr>
<td>Other renewables, low emission, distributed generation</td>
<td>Highly developed</td>
<td>Moderately developed</td>
<td>Minimally developed</td>
</tr>
</tbody>
</table>
Greenest (GS1)
The first scenario is a case where climate change policy moves forward faster than forecast in the baseline generation assumptions. This policy development leads to a carbon price of $50-60/tonne by 2020, nearly double the assumption used in the baseline scenario. This policy development and cost will lead to a number of shifts from the baseline scenario. This includes the potential for higher natural gas prices due to increased demand for the low emission fuel; however, this increase would not be enough to make combined cycle and cogeneration uneconomic relative to coal. Also in this scenario clean coal develops faster as a result of aggressive funding and research across North America and the world. There will also be additional coal retirements due to GHG cost impacts on project economics. Conversely, the greenhouse gas costs provide support for the development for more wind generation beyond that assumed in the baseline generation scenario. Also, policies and initiatives would lead to the development of additional renewables and distributed generation such as biomass, commercial heat and power, waste heat, solar and geothermal.

Overall, in comparison to the baseline, the greenest scenario includes accelerated coal retirements, the addition of clean coal sooner than the baseline and additional renewable development. The specific capacity values by generation type are listed in Table 4-5 and 4-6.

High cogeneration (GS4)
Second is a scenario where additional cogeneration is developed in the oilsands industry beyond that considered in the baseline. This scenario could come about through a policy development that incents cogeneration or a shift in the industry’s historical pattern to build to an overall balance. The only variation in this scenarios from the baseline is the amount of cogeneration developed. In this scenario, an additional 850 MW of cogeneration is developed in the oilsands industry, filling baseload requirements and offsetting combined cycle. The increased cogeneration capacity was determined by increasing the energy produced by cogeneration by 30 per cent. This increase was based on information of all planned cogeneration projects, discussions with developers and general industry trends.

Business as usual (GS5)
The third generation scenario considers a case where climate change policy moves forward at a slower rate than considered in the baseline generation scenario. This leads to a lower price for carbon, implying coal retirements, delayed development of clean coal technologies and less wind development than the baseline generation scenario.

The following table lists the generation additions by technology type for all the generation scenarios. The generation mixes for each of the scenarios in 2020 and 2029 is shown in Figure 4-4 and Figure 4-5 respectively. It is not until 2029 that the distinction in the generation mixes across the scenarios begins to emerge.
Table 4-5: Details of test generation scenarios by 2020

<table>
<thead>
<tr>
<th>Generation scenario</th>
<th>Greenest (GS 1)</th>
<th>Baseline (GS 2,3)</th>
<th>Cogen (GS 4)</th>
<th>BAU (GS 5)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020 forecast Alberta winter peak demand (FC2009)</td>
<td>15,162</td>
<td>15,162</td>
<td>15,162</td>
<td>15,162</td>
</tr>
<tr>
<td>10% effective reserve margin</td>
<td>1,516</td>
<td>1,516</td>
<td>1,516</td>
<td>1,516</td>
</tr>
<tr>
<td>Effective generation capacity required to meet peak demand and reserve margin</td>
<td>16,678</td>
<td>16,678</td>
<td>16,678</td>
<td>16,678</td>
</tr>
<tr>
<td>Existing generation capacity as of mid 2010</td>
<td>12,745</td>
<td>12,745</td>
<td>12,745</td>
<td>12,745</td>
</tr>
<tr>
<td>Effective existing generation capacity as of mid 2010</td>
<td>11,901</td>
<td>11,901</td>
<td>11,901</td>
<td>11,901</td>
</tr>
<tr>
<td>Retirements to 2020</td>
<td>1,904</td>
<td>1,136</td>
<td>1,136</td>
<td>1,136</td>
</tr>
<tr>
<td>Net effective generating capacity after retirements</td>
<td>9,997</td>
<td>10,765</td>
<td>10,765</td>
<td>10,765</td>
</tr>
<tr>
<td>Total effective generating capacity under expected amount</td>
<td>-6,681</td>
<td>-5,913</td>
<td>-5,913</td>
<td>-5,913</td>
</tr>
</tbody>
</table>

2010 to 2020 additions by fuel type

<table>
<thead>
<tr>
<th>Fuel type</th>
<th>Coal</th>
<th>Cogeneration</th>
<th>Combined cycle</th>
<th>Simple cycle</th>
<th>Hydro</th>
<th>Other</th>
<th>Wind</th>
<th>Total additions from 2010 to 2020</th>
<th>Total effective additions from 2010 to 2020</th>
<th>Total effective generation capacity by 2020</th>
<th>Total installed generation capacity by 2020</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1,104</td>
<td>1,687</td>
<td>1,885</td>
<td>880</td>
<td>100</td>
<td>395</td>
<td>3,364</td>
<td>9,415</td>
<td>6,673</td>
<td>16,670</td>
<td>20,256</td>
</tr>
<tr>
<td></td>
<td>834</td>
<td>1,687</td>
<td>1,935</td>
<td>779</td>
<td>100</td>
<td>290</td>
<td>1,864</td>
<td>7,489</td>
<td>5,948</td>
<td>16,713</td>
<td>19,098</td>
</tr>
<tr>
<td></td>
<td>834</td>
<td>2,537</td>
<td>918</td>
<td>880</td>
<td>100</td>
<td>290</td>
<td>1864</td>
<td>7,423</td>
<td>5,882</td>
<td>16,646</td>
<td>19,032</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1,687</td>
<td>2,535</td>
<td>880</td>
<td>100</td>
<td>140</td>
<td>864</td>
<td>6,666</td>
<td>5,924</td>
<td>16,689</td>
<td>18,275</td>
</tr>
</tbody>
</table>

Total installed generation capacity by 2020
### Table 4-6: Details of test generation scenarios by 2029

<table>
<thead>
<tr>
<th>Generation scenario</th>
<th>Greenest (GS 1)</th>
<th>Baseline (GS 2)*</th>
<th>Baseline (GS 3)**</th>
<th>Cogen (GS 4)</th>
<th>BAU (GS 5)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2029 forecast Alberta winter peak demand (FC2009)</td>
<td>18,695</td>
<td>18,695</td>
<td>18,695</td>
<td>18,695</td>
<td>18,695</td>
</tr>
<tr>
<td>10% effective reserve margin</td>
<td>1,870</td>
<td>1,870</td>
<td>1,870</td>
<td>1,870</td>
<td>1,870</td>
</tr>
<tr>
<td>Effective generation capacity required to meet</td>
<td>20,565</td>
<td>20,565</td>
<td>20,565</td>
<td>20,565</td>
<td>20,565</td>
</tr>
<tr>
<td>peak demand and reserve margin</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Existing generation capacity as of mid 2010</td>
<td>12,745</td>
<td>12,745</td>
<td>12,745</td>
<td>12,745</td>
<td>12,745</td>
</tr>
<tr>
<td>Effective existing generation capacity as of mid 2010</td>
<td>11,901</td>
<td>11,901</td>
<td>11,901</td>
<td>11,901</td>
<td>11,901</td>
</tr>
<tr>
<td>Retirements to 2029</td>
<td>4,270</td>
<td>4,270</td>
<td>4,270</td>
<td>4,270</td>
<td>3,880</td>
</tr>
<tr>
<td>Net effective generating capacity after retirements</td>
<td>7,631</td>
<td>7,631</td>
<td>7,631</td>
<td>7,631</td>
<td>8,021</td>
</tr>
<tr>
<td>Total effective generating capacity under expected</td>
<td>-12,934</td>
<td>-12,934</td>
<td>-12,934</td>
<td>-12,934</td>
<td>-12,544</td>
</tr>
<tr>
<td>amount</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**2021 to 2029 additions by fuel type**

<table>
<thead>
<tr>
<th></th>
<th>Coal</th>
<th>Cogeneration</th>
<th>Combined cycle</th>
<th>Simple cycle</th>
<th>Hydro</th>
<th>Nuclear</th>
<th>Other</th>
<th>Wind</th>
<th>Total additions from 2021 to 2029</th>
<th>Total effective additions from 2021 to 2029</th>
<th>Total additions from 2010 to 2020 (see Table 6)</th>
<th>Total effective additions from 2010 to 2020 (see Table 6)</th>
<th>Total effective generation capacity by 2029</th>
<th>Total installed generation capacity by 2029</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>350</td>
<td>970</td>
<td>270</td>
<td>970</td>
<td>970</td>
<td>620</td>
<td>850</td>
<td>2,500</td>
<td>9,089</td>
<td>6,189</td>
<td>9,415</td>
<td>6,673</td>
<td>20,463</td>
<td>26,979</td>
</tr>
<tr>
<td>Cogeneration</td>
<td>185</td>
<td>865</td>
<td>865</td>
<td>1,205</td>
<td>1,205</td>
<td></td>
<td></td>
<td></td>
<td>9,368</td>
<td>7,018</td>
<td>7,489</td>
<td>7,489</td>
<td>20,597</td>
<td>25,332</td>
</tr>
<tr>
<td>Combined cycle</td>
<td>700</td>
<td>2,730</td>
<td>2,397</td>
<td>1,500</td>
<td>1,500</td>
<td>1,000</td>
<td>700</td>
<td>2,000</td>
<td>9,375</td>
<td>7,025</td>
<td>7,489</td>
<td>7,489</td>
<td>20,604</td>
<td>25,339</td>
</tr>
<tr>
<td>Simple cycle</td>
<td>704</td>
<td>603</td>
<td>643</td>
<td>486</td>
<td>518</td>
<td></td>
<td></td>
<td></td>
<td>9,361</td>
<td>7,011</td>
<td>7,423</td>
<td>6,666</td>
<td>20,524</td>
<td>25,259</td>
</tr>
<tr>
<td>Hydro</td>
<td>1,800</td>
<td>1,500</td>
<td>1,500</td>
<td>1,500</td>
<td>500</td>
<td></td>
<td></td>
<td></td>
<td>9,361</td>
<td>7,011</td>
<td>7,423</td>
<td>6,666</td>
<td>20,524</td>
<td>25,259</td>
</tr>
<tr>
<td>Nuclear</td>
<td>2,000</td>
<td>1,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>8,143</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td>850</td>
<td>700</td>
<td>700</td>
<td>700</td>
<td>450</td>
<td></td>
<td></td>
<td></td>
<td>8,143</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wind</td>
<td>2,500</td>
<td>2,000</td>
<td>2,000</td>
<td>2,000</td>
<td>1,500</td>
<td></td>
<td></td>
<td></td>
<td>8,143</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

* Coal renaissance
** Nuclear develops
Further details on how this information was used in creating the transmission plan are found throughout the main body of the document.
Appendix F

Interties

BACKGROUND

Electricity is the backbone of Alberta’s economy, and transmission is critical to ensure the delivery of electricity to meet load growth in the residential, commercial and industrial sectors. The interties in Alberta have historically played an important role in supporting both the reliability of the grid as well as the marketplace. Interties link Alberta to integrated markets in B.C. and points west, Saskatchewan and points east and, with the pending new intertie, directly to the U.S. through Montana. These interconnections ensure access to additional supplies of electricity and additional ancillary services to serve load and reliability objectives. The interties also effectively increase the size of the market that both generators and loads can access.

The Long-term Transmission Plan (filed June 2012) – also referred to as the LTP or the Plan – considers both the restoration of the interties and future development in its assessment – both as part of the baseline to support current generation and load patterns, but additionally in analysis of scenarios based on climate change and different fuel mixes to replace plant retirements. This section will review the transmission planning analysis related to interties. Background information examining current usage of the interties and their context in the market is presented first. Following this is a brief examination of the legislative and policy principles that guide the AESO’s intertie work, and a high-level discussion regarding the criteria the AESO should employ when planning new interties. Finally, more detail regarding immediate next steps is presented.
Figure 1 illustrates Alberta’s interties in comparison to a selection of other provinces.
Relative to our system demand, Alberta’s intertie capacity is notably lower than other areas.

Figure 1: Interconnections as a percentage of peak load

[Diagram showing interconnections as a percentage of peak load]

**Current available transfer capability**

Alberta is currently interconnected to the east and west and with future developments will be connected to the south by a merchant line. Through these interconnections, the Alberta electricity market can trade with other participants in other jurisdictions competing with Alberta generators and provide export opportunities for Alberta generators as well. Alberta market participants have access to B.C. and through B.C. to the U.S. Pacific Northwest and other western markets. In the east, Alberta can access Saskatchewan and, through Saskatchewan, the Midwest Independent System Operator (MISO) trading area or other points east. In addition, the Montana-Alberta Tie Line (MATL) line will link Alberta to Montana, creating our first direct line to the U.S.

There is currently a 500 kilovolt (kV) circuit and two 138 kV circuits between Alberta and B.C. These three circuits collectively are defined by the Western Electricity Coordinating Council (WECC) as Path 1. The path rating of the B.C. intertie is 1,000 megawatts (MW) in an export mode and 1,200 MW in an import mode. The actual operating limit is lower because of current system constraints and operating parameters required to maintain Alberta Reliability Standards in the event of (1) intertie separation while importing or exporting, (2) system limits due to South of KEG (Keephills-Ellerslie-Genesee) flow, and (3) voltage fluctuations in the Calgary area in the event a 240 kV line trips in the Calgary area.

On the Saskatchewan side, Alberta is interconnected with a direct current connection rated at 153 MW for both import and export. Over the course of 2010, the effective rating on this intertie increased from a limit low of 35 MW to its fully restored capacity path rating of 153 MW. The path rating of the MATL currently under construction is 300 MW (import and export).
The interties are operated independently and energy and ancillary services are scheduled across the interties through an open access system (OASIS) that creates electronic tags or e-tags for trading across the various Balancing Authorities. Other jurisdictions have a Federal Energy Regulatory Commission (FERC) compliant tariff that provides for firm and non-firm services. Alberta’s market is a pooled market without transmission rights; accordingly, transmission is allocated to participants (including intertie trades) upon dispatch. The dispatch of interties including congestion management is managed through rules and procedures. While the interties are managed separately, on occasion a congestion event may occur that affects several interties simultaneously. While the AESO will have rules in place to address potential congestion and allocation of available transfer capability (ATC), efforts will also be made to examine how to (a) restore the interties to or near to their full path ratings, and (b) expand the intertie capability to/from Alberta.

**Current usage**

ATC is the effective rating of the intertie hour-over-hour for scheduling purposes. ATC is impacted by intra-Alberta transmission and operational considerations as well as by conditions in adjacent areas. Over the past few years Alberta’s average import and export ATC has been trending upwards. In 2010 this was true for import and export capability on the B.C. intertie and for exports on the Saskatchewan intertie. Saskatchewan import capability was limited in 2010 for a period of time due to unplanned transmission limitations due to a spring storm, thus lowering the average. Table 1 illustrates the maximum and average capability to import and export.

<table>
<thead>
<tr>
<th>Year</th>
<th>B.C. export ATC</th>
<th>B.C. import ATC</th>
<th>Saskatchewan export ATC</th>
<th>Saskatchewan import ATC</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Maximum</td>
<td>Average</td>
<td>Maximum</td>
<td>Average</td>
</tr>
<tr>
<td>2006</td>
<td>735</td>
<td>188</td>
<td>700</td>
<td>607</td>
</tr>
<tr>
<td>2007</td>
<td>735</td>
<td>333</td>
<td>675</td>
<td>517</td>
</tr>
<tr>
<td>2008</td>
<td>735</td>
<td>387</td>
<td>625</td>
<td>468</td>
</tr>
<tr>
<td>2009</td>
<td>735</td>
<td>322</td>
<td>600</td>
<td>449</td>
</tr>
<tr>
<td>2010</td>
<td>735</td>
<td>389</td>
<td>650</td>
<td>507</td>
</tr>
</tbody>
</table>
Alberta has been a net importer of electricity for nine consecutive years (2002-2011). That means Alberta historically buys more power from other jurisdictions to serve Alberta load than is sold as excess from Alberta to other jurisdictions. Table 2 provides a summary of annual import and export schedules over the past five years.

Table 2: Annual intertie schedule statistics

<table>
<thead>
<tr>
<th>Intertie statistics (GWh)</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Imports on B.C. intertie</td>
<td>1,101</td>
<td>927</td>
<td>1,574</td>
<td>1,344</td>
<td>1,846</td>
</tr>
<tr>
<td>Imports on Saskatchewan intertie</td>
<td>416</td>
<td>540</td>
<td>674</td>
<td>675</td>
<td>358</td>
</tr>
<tr>
<td>Total imports</td>
<td>1,517</td>
<td>1,467</td>
<td>2,248</td>
<td>2,019</td>
<td>2,205</td>
</tr>
<tr>
<td>Year-over-year growth (%)</td>
<td>-1.1</td>
<td>-3.3</td>
<td>53.2</td>
<td>-10.2</td>
<td>9.2</td>
</tr>
<tr>
<td>Exports on B.C. intertie</td>
<td>460</td>
<td>886</td>
<td>518</td>
<td>488</td>
<td>411</td>
</tr>
<tr>
<td>Exports on Saskatchewan intertie</td>
<td>29</td>
<td>88</td>
<td>40</td>
<td>25</td>
<td>48</td>
</tr>
<tr>
<td>Total exports</td>
<td>489</td>
<td>973</td>
<td>559</td>
<td>513</td>
<td>459</td>
</tr>
<tr>
<td>Year-over-year growth (%)</td>
<td>-52.8</td>
<td>98.8</td>
<td>-42.6</td>
<td>-8.2</td>
<td>-10.5</td>
</tr>
<tr>
<td>Net yearly imports</td>
<td>1,028</td>
<td>494</td>
<td>1,689</td>
<td>1,505</td>
<td>1,745</td>
</tr>
</tbody>
</table>

In 2010, there was an increase in the amount of time that the B.C. intertie was highly utilized (greater than 80 per cent utilization). Imports flow in response to market opportunities in Alberta and in doing so, enhance system reliability in times when there is insufficient supply within the province to meet demand. At other times, imports provide supply at a lower price than higher-priced dispatched generation in the province.

Over the course of the past three years (2008-2010), Alberta was exporting to B.C. and points west in 29 per cent of the hours. The volumes flowing from Alberta to B.C. were within 80 per cent of the ATC 27 per cent of the hours where Alberta was exporting, and within 95 per cent of the ATC 20 per cent of the exporting hours. Alberta imported from B.C. 61 per cent of the time over the past three years. The intertie schedules were within 80 per cent of the ATC in 31 per cent of hours where Alberta was importing, and within 95 per cent of the ATC in 23 per cent of importing hours. These figures indicate that there are numerous periods of time when the amount of ATC actually limits the amount of energy that can be transacted between these jurisdictions. The same is true on the Alberta-Saskatchewan border. Figure 2 illustrates the number of hours the intertie utilization has exceeded 80 per cent over the past five years.

Typically import utilization is highest during on-peak, high-load hours and exports occur during light-load hours. Import utilization also typically is highest during hours where the pool price is relatively high. Figure 3 illustrates that near to full utilization of the existing intertie capability for imports occurs frequently when prices are relatively high in Alberta, indicating that imports compete with Alberta generation as prices rise.
Currently, Alberta’s limited connections to neighbouring markets is accompanied by a relatively large divergence between prices in Alberta and in its neighbouring markets. While these price differences are due to many factors, including differences in generation mix and market structure, limited capability to move power between high and low-priced regions is also a contributing factor. Figure 4 illustrates the differences in prices between Alberta and its two nearest neighbours, where it is noted that frequently there are substantial differences in the price of electricity. Figure 5 illustrates Alberta’s pricing in relation to a selection of relatively nearby price points for energy.
Compared to other jurisdictions in Canada, Alberta’s interconnections with other markets are relatively small given the size of the market. Alberta’s use of the interties has been growing over the past several years. In particular, the trend toward increasing import flows indicates greater reliance on the interties to provide energy supply to the province. This underscores the importance of interties from a reliability perspective. Interties linking Alberta to other markets are also an important and well-functioning part of the overall market, with import and export flows responding to market price incentives.

**Legislative authority**

The inclusion of interties in the AESO’s long term planning process is guided by several legislative and policy statements. Government policy indicates that the AESO is responsible for long-term transmission system planning and development. As is spelled out by the Electric Utilities Act, this must be done in a fair, efficient and openly competitive manner while ensuring system reliability:

5: “The purposes of this Act are

- (b): to provide for a competitive power pool so that an efficient market for electricity based on fair and open competition can develop, where all persons wishing to exchange electric energy through the power pool may do so on non-discriminatory terms and may make financial arrangements to manage financial risk associated with the pool price;”

Accordingly, the AESO must include interties in transmission analysis to facilitate and promote market efficiency by providing access in and out of Alberta. In doing so, AESO will further support reliability by providing access to new ancillary services and support for the Alberta balancing authority.

The AESO has specific obligations regarding interties, clearly stated in government policy. The Transmission Development Policy (TDP) of 2003 identifies a role for interties in the competitive market while also outlining the intention for cost allocation of future interties:

“Interties are an essential part of a competitive market both as a means to import power when needed, and to export surplus energy and to support effective functioning of the wholesale market. Without such capabilities, market signals and wholesale prices are distorted and unreflective of true market conditions. Since the ability of inter-ties to exchange electricity in both directions (i.e., import and exports) is essential to a robust wholesale market and a reliable electric system, the cost for internal reinforcements and remedial action schemes (RAS) arrangements to allow the inter-ties to function as designed will be allocated to load.”

“Projects primarily intended for export should be considered on a case-by-case basis. Pricing for such projects would normally be paid by the project beneficiaries (i.e., the exporters). Where residual benefits to the internal grid are demonstrated, consumers may fund system upgrades, in a manner consistent with the benefits.”
As outlined in the *Provincial Energy Strategy* of 2009, Alberta needs to expand and diversify interties to support markets and reliability:

“Generation sources are becoming more diverse as renewable energy grows, testing the grid in new ways and creating pressures not experienced before. Our system also remains one of the least ‘interconnected’ in the country with limited capacity to either import or export electricity when necessary to maintain the integrity of the grid. This creates challenges for safety, reliability and affordability.” (Section 1.5)

Accordingly, as noted in the TDP, the *Long-term Transmission Plan* will reflect the objective that “Alberta will take the following steps to strengthen the provincial transmission system:

- Adopt and implement a policy to build interties to other markets to ensure an adequate supply of electricity to Alberta as well as to facilitate development of additional wind generation.”

Alberta’s *Electric Policy Framework* of 2005 also identified a need for interties:

4.3.3: “The Department believes that strong interconnection capacity with neighbouring jurisdictions may, in the long term, contribute to address or significantly mitigate long term adequacy concerns for Alberta. The Transmission Regulation plays an important part in this. Firstly, the Regulation will contribute to reinforce the transmission system to allow the interties to transfer to their capability limits. Secondly, the Regulation also creates the framework for the development of merchant transmission lines to increase transmission interconnection capacity with neighbouring jurisdictions.”

Specifically, plans for future transmission must also provide for either rate base or merchant interconnections. As referenced in the *Electric Utilities Act*:

33: “The Independent System Operator must forecast the needs of Alberta and develop plans for the transmission system to provide efficient, reliable and non-discriminatory system access service and the timely implementation of required transmission system expansions and enhancements.”

Finally, as stated in the *Transmission Regulation*, the AESO must work to restore current interties.

16(1): “In making rules under section 20 of the Act, and in exercising its duties under section 17 of the Act, the ISO must prepare a plan and make arrangements to restore each intertie that existed on August 12, 2004 to, or near to, its path rating.”
Evolution of future interties – criteria and analysis

This section outlines the high-level considerations for criteria that will be developed in consultation with stakeholders. The policy direction makes it clear that intertie capacity is important for both a well-functioning market and reliable electric system, and expansion of intertie capability should form a part of the AESO’s long-term plans. Given this, the need for additional interconnection capacity will be evaluated based on both market and reliability criteria. Alberta does not run an integrated planning process with its neighbouring jurisdictions.

Further work is required to evaluate in detail when, where, how, and to what size future interties should be built and what choice of technology is most beneficial for our system. The AESO will work with stakeholders to evaluate these questions and include updates on this analysis in future long-term transmission plans. As a start, the AESO will work with stakeholders to develop the criteria for assessment of new interties, noting that policy is clear that expanded interconnections are part of the vision for transmission. These criteria should fall into two main categories: market benefits and reliability or system benefits.

Market benefits

Alberta’s generation resources are predominantly thermal, with coal and gas-fired plants accounting for over 80 per cent of existing capacity. BC Hydro’s generation resources are predominantly hydroelectric, which provides operational benefits such as energy storage and quick-start generation to meet energy demand and ancillary services needs. One of the key benefits of trading across a larger marketplace is the increased ability for generators to manage their portfolios and more efficiently use baseload and peaking plants.
Access to a larger marketplace provides more trading opportunities for all parties and should increase market liquidity. A larger marketplace also provides for the opportunity for economies of scale and access from other supply sources, thereby supporting reliability through additional supply adequacy. Additionally, the resulting price signal will be more efficient as competition can occur across a larger mix of generation sources.

Currently, Alberta has seen a relatively large divergence between prices in Alberta and in its neighbouring markets since there is little capability to move power between high and low-priced regions due to limited interconnections. Figure 4 illustrates the differences in prices between Alberta and its two nearest neighbours, where it is noted that frequently there are substantial differences in the price of electricity. Figure 5 illustrates Alberta’s pricing in relation to a selection of relatively nearby trading hubs for electricity.

**Figure 4: Difference between Alberta pool price and neighbouring markets (Mid-C and Minn.-Hub)**

![Chart: Difference between Alberta pool price and neighbouring markets](image)

- Alberta to Mid-Columbia price difference
- Alberta to Minnesota price difference
- Estimate of the cost of transmission between Alberta and neighbouring markets (+/- $10/MWh)
Figure 5: 2010 average power prices and volatility\(^1\) in various other jurisdictions ($CAD/MWh)

- **Alberta Pool Price:** $51/MWh
  - Volatility: 38%

- **Mid-Columbia Price:** $29/MWh
  - Volatility: 7%

- **California-Oregon Border Price:** $31/MWh
  - Volatility: 5%

- **North-Point 15 Price:** $31/MWh
  - Volatility: 4%

- **South-Point 15 Price:** $30/MWh
  - Volatility: 6%

- **Minnesota Hub Price:** $20/MWh
  - Volatility: 13%

---

\(^1\) The volatility is measured as the per cent change in the daily average price in comparison to the annual average price (i.e., for Alberta, on average the daily average price varied on average by 38 per cent of the annual average price of $51/MWh, or on average it varied by $19/MWh from day to day).
**System and reliability benefits**

Current interties are limited in operational capacity due to a number of system considerations. For example, while the import path rating for the Alberta-B.C. intertie is 1,200 MW, the intertie needs to be operated at a reduced value to allow for the loss of the largest internal generating unit and to provide a margin for reliable operations. This limits the Alberta-B.C. intertie path for functional available capability as outlined in AESO rules and procedures. These restrictions on the operation of the intertie are not discretionary as they are operational and management criteria stipulated by reliability criteria by both WECC and NERC. These criteria protect against issues between balancing authorities that can occur due to internal system force majeure – effectively requiring Alberta to manage its internal system to recover from the loss of the largest generator without impacting other jurisdictions. Increasing the available capacity through non-wires solutions and additional interties is a high priority to increase these path ratings for both market and operational reasons.

Congestion on the interties limits the ability of the marketplace to access other jurisdictions for trade purposes and limits the ability of the Alberta market to receive imports that could provide additional security in the form of ancillary services as well as energy. The import limit on the Alberta-B.C. intertie noted above is one of a few constraints. Others include the export limit on the same path from the 1,000 MW rated capacity to an operational cap of less than that to allow for contingencies on the B.C. load as well as to manage stability and voltage limits, again as outlined in ISO rules and procedures. In addition, due to load conditions, the export capacity on the Alberta-B.C. intertie is limited to 0 MW in many hours of the year, thereby prohibiting opportunities for market or reliability efficiencies. A new constraint will be added with the introduction of the Montana-Alberta intertie (MATL). Until the AESO has completed operational studies and implemented any necessary solutions, this new 300 MW line must effectively share capacity with the Alberta-B.C. intertie to meet operating criteria for stability. It is the AESO’s plan to address these congestion issues through the use of non-wires solutions in the short term and to support new interties to restore the operational limits of the current interties and provide additional access to and from other markets.

As noted in various WECC/NERC studies, larger markets assist in managing variability across the system related to changes in generation, particularly intermittent resources like wind. As Alberta’s wind resources develop, additional transfer capability along with sharing agreements can support diversity across the interties, thereby potentially increasing our capacity to integrate more renewables. Finally, additional interties would increase the overall stability, reliability and operational control of the respective transmission systems and may increase the transfer capability of each respective system.
Next steps
The AESO is presently focused on four related streams of work. These include: (1) restoring the interties, (2) development of an intertie framework, (3) conducting transmission studies and scenarios internally to Alberta and in conjunction with the WECC to evaluate the technical requirements needed to support intertie expansion and (4) development of a process for integration of future merchant interties into the system. Each of these elements is outlined below. It should be noted that much of the study work will be conducted over the next years with the goal of working with stakeholders to develop the criteria for future restoration and expansion work, as well as technical studies to examine what size and location may be considered for intertie expansion in the future.

Restoring the interties
Alberta currently has two interties with other jurisdictions, and these interties are subject to congestion that reduces the available transfer capacity (ATC) below the path rating. The B.C. intertie is rated at 1,200 MW for imports and 1,000 MW for exports, but the AESO is unable to schedule power flows to these levels due to reliability requirements. Recent ATC limits with all transmission elements in operation are rarely over 600 MW for imports and are a maximum of 735 MW for exports. The Saskatchewan intertie is rated at 153 MW for both imports and exports, and ATC limits are usually at these levels when all transmission elements are in service.

The AESO has been in consultation with stakeholders to identify options to restore the Alberta-B.C. intertie to its rated capacity. Current operating limits for imports over the Alberta-B.C. intertie are constrained because at high import flows, the intertie is the largest single supply contingency in Alberta and because the intertie must be kept within path limits should the largest internal Alberta generator trip offline. Export limitations include internal transmission constraints, voltage stability limits, over-frequency protection for the loss of the intertie and B.C. internal constraints.

Import restoration is generally a function of protecting the Alberta system against the loss of the Alberta-B.C. intertie when imports are at a high level. If imports are greater than 450 MW, the intertie is the single largest contingency on the system and system stability must be maintained following the loss of this supply. Frequency responsive load shed service (LSS) and interruptible load remedial action scheme (ILRAS) are two products that are currently used to support imports. ILRAS is available during emergencies and LSS provides up to 150 MW of permanently armed load. As a result, import ATC from B.C. is currently limited to 600 MW or lower under normal operating conditions.

The AESO is currently proceeding with an ancillary service product called load shed service for imports (LSSi) to increase import ATC on the Alberta-B.C. intertie. This service is expected to be available in the second half of 2011, and is anticipated to increase import ATC on the existing intertie from current effective maximum levels under high load conditions. On average, LSSi is expected to increase ATC by 100 MW to 150 MW relative to current limits, assuming the service is fully subscribed. The AESO will be soliciting proposals for options to further increase import capacity, and this process is planned to begin in mid-2011.

---

2 Based on available load shed service contract levels import ATC on the B.C. tie should not exceed 600 MW.

3 Under OPP 801, the AESO can arm ILRAS, which allows imports to be increased above 600 MW in emergency conditions.
Export restoration requires resolving a range of constraints that currently limit export ATC to a maximum of 735 MW and an average of less than 400 MW. Internal transmission limits are the most frequent limitation on exports at this time, although voltage stability limits, over-frequency protection for the loss of the intertie and B.C. internal constraints also limit exports under some system conditions. The AESO will be looking for proposals in the second half of 2011 to increase export capacity through addressing one or more of the limitations.

This process will allow market participants to develop options for the AESO to examine that meet the mandate of restoring interties to their rated capacity or close to it. In short, the AESO will study and address current import and export constraints on the Alberta-B.C. intertie and in combination with the new MATL and develop further plans to address constraint issues.

**Intertie framework**

It is recognized that there are challenges created by trading across the interties, particularly to markets of different structures and with different tariffs and market timing. These issues are referred to as seams issues. There is no question that issues related to seams need to be addressed to ensure that potential efficiencies intended by expanded interties can be realized. As the AESO works to evaluate ways to expand the operation of the current interties and consider new interties, work is also proceeding on financial and market design issues related to tariff, cost allocation, dispatch and ATC allocation. While some of this work can occur in Alberta, much of it involves integration with other trading areas to coordinate dynamic scheduling, market timing and tariff products.

The AESO is working to develop an intertie framework that addresses the issues related to market timing, product differences, scheduling protocol and allocation issues during times of constraint. As noted in the market policy of 2005, to the extent possible, interties will be treated like a load or generator at the border and the rules related to the energy market, ancillary services market and operational dispatch will, to the extent possible, be similar to rules for internal Alberta participants.

The AESO consulted with stakeholders on the intertie framework in 2010 and issued a recommendation paper outlining four key elements including: (1) dynamic scheduling and priced bids/offers, (2) system planning (3) merchant tariff, and (4) ATC allocation rules consistent with internal congestion management. The AESO has commenced rule consultation on the ATC allocation methodology of price then pro rata. It is an AESO priority to advance work on dynamic scheduling in 2011 to enable the pricing of intertie bids and offers. The key feature of the intertie framework will be to ensure that market rules, system operations and transmission plans recognize current interties and expansion of future interties.
Transmission studies/scenarios

Transmission planning for both internal transmission interconnections as well as for transmission across the interties must address the market criteria discussion in the previous section and satisfy reliability design criteria. As noted, the current interties are limited in operation due to criteria established by the WECC or NERC for operations across balancing authorities. The AESO must design the system to manage congestion and contingencies in a safe and secure fashion. Further transmission studies are required to assess the impact of pending and future interties on the system.

Market design work to integrate interties into the market also relies on integrating and supporting interties on the grid. The AESO will evaluate what transmission system restoration is required to provide long-term support to current and future interties. As part of this, the AESO will advance consultation with stakeholders on the merchant transmission tariff. The framework is important to establish rules and procedures for integrating any new interties on to the grid.

While additional intertie capacity has been the topic of discussion for several years by policy makers and stakeholders, more work is required to conclude recommendations for future interties as part of the AESO's long-term planning. As the forecast generation mix changes, there may be a greater reliance on interties and that may dictate both size and location for expansion. Further work is required to assess how to meet the policy objective of expanding system access to larger markets.

At present, the AESO has included the following in the LTP:

- restoration of existing interties to their rated capacity as required by the T-Reg
- development of market rules and products to support a sustainable intertie framework
- plans to conduct transmission analysis to evaluate where, what size and when future interties may be required
- plans to define and implement the processes and planning to connect pending and future merchant interties

Facilitating merchant interties

The process to be followed related to supporting merchant transmission developments is provided here for clarity. The Transmission Regulation provides the following direction in Section 27:

- Assessment of need and usage of the interties.
- A requirement for merchant owners to support Needs Applications by the AESO.
- Terms and conditions for future merchant interties including cost allocation and access.

The AESO will continue to work with stakeholders to examine a tariff for new merchant lines, to provide clarity to work related to Needs Information Documents by merchant providers as well as to identify other processes that are required by a merchant developer working with the AESO to build, connect and operate a potential merchant line.
Appendix G

Advancements in Transmission Technology

This appendix is a general discussion of some of the technologies that are advancing the transmission of electricity.

**HIGH VOLTAGE DIRECT CURRENT (HVDC)**

The Alberta Interconnected Electric System (AIES) operates using three-phase alternating current (AC) transmission. This means that transmission circuits in Alberta consist of three sets of conductors, one set per phase, to carry energy and may include additional conductors installed higher on the structure that act as overhead shield wire(s) to shield the current-carrying lines beneath from lightning strikes. In both AC and direct current (DC) systems, high voltage is advantageous when transmitting energy as it minimizes losses in the transmission process.

When integrating a DC transmission facility with an AC system, conversion terminals are required at either end of a DC transmission line and are an integral part of the high voltage direct current (HVDC) system. The terminal that converts AC to DC is called a rectifier terminal and the terminal that converts from DC back to AC is called an inverter terminal. Instead of the set of three current-carrying conductors used in an AC system, a DC system requires two sets of current-carrying conductors. This type of DC system is described as bipolar. In some cases a third set of conductors is required to provide a metallic ground current path. The reduction in conductor sets leads to smaller towers and reduced right-of-way requirements compared to AC.

DC is mainly used for long distance transmission. Where appropriate, HVDC offers high capacity and efficiency with a lower right-of-way requirement than AC alternatives. HVDC lines have lower transmission losses over long distances than AC lines. Cable and tower costs are typically lower for DC transmission. However, the lower line costs of DC systems are offset when the costs of the inverter and rectifier terminals required at either end are included. There are numerous variables involved; however, DC for overhead lines is generally more economic than AC when the transmission distance is greater than 700 kilometres (km).
HVDC projects have achieved power ratings of up to 3,000 megawatts (MW) at ±500 kilovolts (kV). The need to move large amounts of power over longer distances is pushing HVDC into the next frontier (voltage levels above ±600 kV) of ultra high voltage direct current (UHVDC). UHVDC projects are being planned that will provide power ratings in excess of 4,000 MW at ±600 kV.

One characteristic of DC transmission is that it does not allow the flexibility of interconnection along the transmission route that AC transmission does. This is because an inverter station is required at every interconnection point to convert from DC back to AC to be able to make use of the energy. In AC transmission, interconnections can be made almost anywhere and transformers can be used to increase or decrease the voltage. Typical HVDC systems have a converter station at each of the sending and receiving ends with an HVDC line connecting the two, thereby creating a two-terminal HVDC line. When more than one two-terminal HVDC line is being considered, it is possible to reduce the overall cost of the development by designing a multi-terminal HVDC system that essentially combines the converter stations at the common point into one facility.

There is a technical limit as to the number of converter stations that can be simultaneously operated on a DC transmission line. Currently the maximum number of terminals in operation on a multi-terminal HVDC line in the world is three.

Some examples of HVDC currently in use in Canada include HVDC transmission lines in Manitoba and Quebec. There are also HVDC lines operating within the Pacific Northwest and the California-Nevada areas of the U.S.

The Alberta and Saskatchewan electric systems are interconnected through a back-to-back HVDC converter station that is owned and operated by ATCO Electric. The back-to-back aspect of the intertie refers to the fact that there is no transmission line involved. The AC of the AIES is converted to DC and then immediately from DC back to AC to connect to Saskatchewan’s transmission grid (and vice versa). Whereas AC in North America operates at a frequency of 60 Hertz (Hz), DC has a frequency of zero. As a result, a back-to-back HVDC converter configuration such as the intertie connecting the Alberta and Saskatchewan electric systems prevents problems affecting frequency on the Western Interconnection (see Figure 1), to which the AIES belongs, from impacting the Eastern interconnection, to which Saskatchewan’s transmission grid belongs.
North America, including Canada and Mexico, is divided into three separate transmission interconnections: the Eastern Interconnection, the Western Interconnection and the Texas Interconnection. WECC is the Western Electricity Coordinating Council.

**Flexible AC transmission systems (FACTS) devices**

Traditionally, strengthening power grids has involved construction of new transmission lines. However, as these have become more difficult and more expensive to site, industry has responded by developing new technologies. FACTS devices are a family of controllers integrated into a transmission system to allow improved power flow management and control. It is estimated that FACTS devices can boost the transmission capacity of lines now limited by voltage or stability considerations by as much as 20 to 40 per cent.

FACTS devices tend to be highly technical. An overview of the major FACTS devices is provided in Figure 2. The left column identifies conventional devices that use fixed or mechanically switchable components that alter the physical electric system characteristics of resistance (R), inductance (L) and capacitance (C). FACTS devices contain these components as well, but came about as a result of the increased rating and improved performance of power electronics. Power electronic valves and converters allow faster switching in smaller steps. This combination allows FACTS devices to better control elements of the power system such as voltage, reactive power and impedance resulting in such benefits as the ability to dampen power system oscillations and actively filter out unwanted harmonics and phase unbalance. FACTS devices are also considered static; however, since unlike the mechanical switching required in conventional devices, they have no moving parts.

---

**Figure 2: Overview of major FACTS devices**

<table>
<thead>
<tr>
<th>Conventional (switched)</th>
<th>FACTS devices (fast, static)</th>
</tr>
</thead>
<tbody>
<tr>
<td>R, L, C, transformer</td>
<td>Thyristor valve</td>
</tr>
<tr>
<td>Shunt devices</td>
<td>Voltage source converter (VSC)</td>
</tr>
<tr>
<td>Switched shunt-compensator (L, C)</td>
<td>Static VAr compensator (SVC)</td>
</tr>
<tr>
<td>Series devices</td>
<td></td>
</tr>
<tr>
<td>(Switched) series-compensation (L, C)</td>
<td>Thyristor controlled series compensator (TCSC)</td>
</tr>
<tr>
<td>Phase-shifting transformer</td>
<td></td>
</tr>
<tr>
<td>Shunt and series devices</td>
<td></td>
</tr>
<tr>
<td>HVDC back-to-back (HVDC B2B)</td>
<td></td>
</tr>
<tr>
<td>Shunt and series devices</td>
<td></td>
</tr>
</tbody>
</table>

---

Resistance (R), inductance (L) and capacitance (C) are basic components of the transmission system. The resistance, measured in ohms (Ω), of transmission line conductors, is the most significant cause of power loss in a transmission line. In the very simplest of terms:

\[
\text{Resistance} = \frac{\text{power loss in a conductor}}{\text{(current in a conductor) x (current in a conductor)}}
\]

The inductance (L), measured in henrys (H), is the property of the transmission line that relates the voltage induced by changing flux to the rate of change of the current. The capacitance (C), measured in farads per metre (F/m), is the charge on the conductors per unit of potential difference between them.

“Technology development has opened new ways of managing grids. Progress in static reactive power compensation and power storage technologies enables new sources of electrical energy to be connected to existing grids. Power electronics have made it possible to control grids and new FACTS (flexible AC transmission systems) devices are improving controllability.”


Photo courtesy of Siemens Energy.
Overview of major FACTS devices

Some of the devices now included under the FACTS umbrella pre-date the introduction of the FACTS concept. The AIES installed a static voltage-ampere reactive compensator (SVC) near Langdon in 1986. SVCs are the simplest of the FACTS devices and are used for reactive power control. Table 1 shows the estimated number of worldwide installed FACTS devices and their estimated total installed power.

Table 1: Estimated number of worldwide installed FACTS devices and their estimated total installed power

<table>
<thead>
<tr>
<th>Type</th>
<th>Number</th>
<th>Total installed power (MVA)*</th>
</tr>
</thead>
<tbody>
<tr>
<td>SVC</td>
<td>600</td>
<td>90,000</td>
</tr>
<tr>
<td>STATCOM</td>
<td>15</td>
<td>1,200</td>
</tr>
<tr>
<td>Series comp.</td>
<td>700</td>
<td>350,000</td>
</tr>
<tr>
<td>TCSC</td>
<td>10</td>
<td>2,000</td>
</tr>
<tr>
<td>HVDC B2B</td>
<td>41</td>
<td>14,000</td>
</tr>
<tr>
<td>HVDC VSC B2B</td>
<td>1 + (7 with cable)</td>
<td>900</td>
</tr>
<tr>
<td>UPFC</td>
<td>2-3</td>
<td>250</td>
</tr>
</tbody>
</table>

* MVA: megavolt-ampere

In Kayenta, Arizona, Siemens built the world’s first continuously controlled three-phase series compensator. The system has been in operation since 1993.

HVDC VSC

HVDC voltage source converter (VSC) technology takes advantage of the complementary nature of HVDC and FACTS technologies. These systems incorporate HVDC lines with the VSC technology of FACTS devices allowing very rapid voltage, power and stability control. There are at least two commercial versions of such systems: HVDC Light® by ABB Ltd. (Figure 3) and HVDC PLUS (Power Link Universal System) by Siemens (Figure 4). Currently there are nine installations utilizing ABB’s HVDC Light®, eight of which are underground or sub-marine installations, and three more projects identified to be in service by 2010. The first Siemens HVDC Plus installation is scheduled to be in service by 2010 on the Trans Bay project in California.

Figure 3: Shoreham HVDC Light converter station

HVDC Light® was designed by ABB in 1997 to transmit power underground, under water and over long distances.

Figure 4: HVDC PLUS

The Siemens high voltage direct current transmission system HVDC Plus is based on a new generation of power converters using VSC technology.

“Transmission and distribution of electrical energy is not possible without losses in the lines, but high voltage DC and FACTS (Flexible AC Transmission Systems) offer excellent ways to reduce these losses.”


7 From ABB Review 2/2007, p. 3.
Wide-range monitoring systems

There is also a group of technologies whose goal is to provide detailed and timely information on grid status as a means of improving grid management. These systems measure and monitor system operating parameters over a large portion of the system and rely on high-speed communications to be effective. An example of this technology is referred to as wide area measurement systems (WAMS); however, the terms wide area monitoring systems and wide area control systems also refer to technology of this type. One of the first monitoring concepts relying on new measurement technologies was ABB’s voltage instability predictor (VIP). The VIP provides a transmission system operator with a local measure of the power margin before voltage collapse at a particular substation occurs.

Another example of the types of components that provide information into these innovative wide-range monitoring systems is the phasor measurement unit (PMU). These units provide time-synchronized values of the local magnitudes and angles of sinusoidal signals with high resolution in the time domain. PMUs are a common component of the AIES, but they are not currently used for real-time operations. PMUs are used for disturbance monitoring, performance monitoring and validation. The AESO is an active member of WECC’s Disturbance Monitoring Work Group and participates with a number of other organizations in WECC on a WAMS initiative that utilizes PMUs. A real-time dynamic monitoring system workstation for offline analysis by the California Independent System Operator (CAISO) is a product of the initiative. One example of a direct benefit of the initiative is Southern California Edison’s (SCE) power systems outlook software, which has been used by SCE for post-disturbance analysis and is currently demonstrating its real-time capabilities in their grid control centre. The AESO is working towards incorporating PMUs into its real-time operations.

High temperature superconductors

Research into superconductivity, a laboratory phenomenon of zero electrical resistance occurring in certain materials at extremely low temperatures, has provided the electric utility industry with the more practical high-temperature superconducting (HTS) technology. HTS cables have some resistance, but can improve line losses from the five to eight per cent experienced with traditional power cables to approximately 0.5 per cent. The refrigeration required to super cool the HTS cables is generally supplied by liquid nitrogen. HTS cables are said to be able to carry approximately five times as much power as traditional copper wires with the same dimensions. The benefits of HTS also apply to power system components such as transformers. Due to refrigeration costs, superconductors are more expensive than traditional conductors and are suitable for only select projects.

HTS cable is currently being tested in Albany, New York by the U.S. Department of Energy and is being installed in Lower Manhattan, New York by the U.S. Department of Homeland Security working with Consolidated Edison. The Albany project is a 350 metre length of conductor that will be installed between two substations.

---

Underground transmission lines

Underground installation of transmission lines is an important area of development. HTS cables, for example, require underground installation. The non-superconducting conductor that is being increasingly used for burial of transmission lines is XLPE cable, which is insulated by a solid material (polyethylene). Although first introduced commercially in the 1960s, XLPE use at 230 kV or above was rare until recently. XLPE cable, often referred to as extruded cable because of the method used to apply the insulation, is now being used for voltages up to 500 kV.

According to a 2006 Report of the Joint Legislative Audit and Review Commission to the Governor and The General Assembly of Virginia, underground lines are typically four to 10 times more expensive than overhead lines.

HVDC VSC cables have been developed specifically for underground burial. Currently there are eight underground or sub-marine installations utilizing HVDC VSC technology. These installations have been for moderate capacity and relatively short distances. The longest installation to date is the Murraylink project in Australia. The route traverses over 180 km through national parks and significant Aboriginal heritage sites transmitting 220 MW.

Due to its high cost, underground installation of transmission lines is typically limited to environmentally sensitive or extremely congested areas. The latter reason (lack of available aerial transmission corridors and the difficulties involved in obtaining suitable rights-of-way) contributed to the decision to install 9.4 km of 240 kV XLPE underground cable in the downtown Edmonton area.
Composite conductors

Another advancement in transmission line technology is the composite conductor. Aluminum conductor steel-reinforced (ACSR) refers to a commonly used type of overhead conductor composed of a central steel core for physical strength surrounded by stranded aluminum conductors that conduct electricity. New cores developed from composite materials reduce the sagging ACSR conductors experience at high temperatures. Reduced sagging eliminates the need to derate lines operating at higher temperatures.

Figure 5: Designed to increase clearance – less sag at high temperature

(Appoints simple replacement on existing structures)

<table>
<thead>
<tr>
<th>Height above ground (feet)</th>
<th>Existing line steel ACSR</th>
<th>3M ACCR conductor</th>
</tr>
</thead>
<tbody>
<tr>
<td>70</td>
<td>1,200 amps</td>
<td>2,400 amps +100%</td>
</tr>
<tr>
<td>60</td>
<td></td>
<td></td>
</tr>
<tr>
<td>50</td>
<td></td>
<td></td>
</tr>
<tr>
<td>40</td>
<td></td>
<td></td>
</tr>
<tr>
<td>30</td>
<td>Design sag (80°C)</td>
<td></td>
</tr>
<tr>
<td>20</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>High temp sag (240°C)</td>
<td></td>
</tr>
<tr>
<td>0</td>
<td>NESC* clearance</td>
<td></td>
</tr>
<tr>
<td></td>
<td>High temp sag (240°C)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Tower spacing (feet)</td>
<td></td>
</tr>
<tr>
<td>0</td>
<td>1,150</td>
<td>2,300</td>
</tr>
</tbody>
</table>

230 kV thermal upgrade
(+500 MVA increase)  

Aluminum conductor composite reinforced (ACCR)

* NESC: National Electrical Safety Code

The smart grid/intelligent grid/super grid

Moving to a more wholistic view of the transmission system, new concepts are emerging under the umbrella names Smart Grid, intelligent grid or IntelliGridSM and super grid. Research Reports International describes the Smart Grid as “the next phase in the evolution of electrical power generation, transmission and distribution” and as a “fully automated power delivery network that monitors and controls every customer and node, ensuring a two-way flow of electricity and information between the power plant and the appliance, and all points in between.”

A broad range of products is being implemented in support of this new type of grid. A few examples are:

- In Dallas, Texas, the CURRENT Smart Grid™ system links the utility’s control centre to devices in a consumer’s home, such as programmable communicating thermostats and load control switches, using a high-speed broadband over the power line network. This link allows consumers to participate in programs designed to reduce electricity demand and the utility to verify, in real-time, that a reduction in load has occurred.

- Remotely readable transformer monitors provide adjustable sampling rates as frequently as once every seven minutes for critical fault gases, an important indicator of a transformer’s overall condition. AltaLink Management Ltd. (AltaLink), which uses online transformer monitors, believes that by monitoring these critical assets it is able to lower its maintenance costs and extend the lives of transformers while deferring capital expenditures. In the past AltaLink relied on two age-sensitive triggers to maintain all components of its transmission system: time and number of operations. Because factors other than age and number of operations, including temperature, load, fault currents and constantly changing operating conditions can affect the useful life of a transformer, it is important to have other measures of transformer performance. Intrusive maintenance performed to determine a transformer’s condition is no longer cost effective or necessary with the introduction of monitoring devices and computerized analytical diagnostic tools.

- As a pilot project for the AESO, AltaLink installed dynamic thermal line rating units on a transmission line in southern Alberta between Pincher Creek and the Peigan substation. Line ratings represent the maximum allowable power flow through a transmission line and are based on line ampacity (the physical capability of a line to carry current), ambient temperature, conductor temperature and wind speed. In the past, winter and summer line ratings have been established based on assumptions about these factors (and considering a safety factor), and the line has been operated only up to these seasonal ratings. This pilot project will provide system operators with real-time information about the line, which allows them to increase the amount of power flowing on the line under certain conditions. This operating flexibility helps increase system reliability and creates the opportunity to reduce congestion.
Another wholistic approach to improving the movement of electricity is the concept of a continental super grid. According to Thomas J. Overbye, a professor in electrical and computer engineering at the University of Illinois at Urbana-Champaign, “In short, the super grid concept envisions the use of underground, superconducting direct current cables for long distance power transmission at levels of perhaps five to 10 gigawatts.”10

Other efforts are underway to develop the IntelliGrid – a nimbler, more flexible network that marries electric power with cutting-edge communication and computing capabilities. This initiative intends to move the grid from a patchwork of proprietary information systems to a system with standardized interfaces so new applications can be easily commissioned. The international consortium pursuing this goal consists of the Electric Power Research Institute, electric utilities, public agencies and leading equipment manufacturers.

**Nanotechnology**

Nanotechnology is a popular current research area that has the potential to significantly change the electric utility industry. Carbon nanotubes, which are about the size of a human hair, are long, thin cylinders of carbon that can be single- or multi-walled (cylinders inside the other cylinders). Carbon nanotubes have a broad range of electronic, thermal, and structural properties that change depending on the different kinds of nanotube (defined by its diameter, length and spiral quality). Carbon-nanotube wire product (also called armchair quantum wire for the type of nanotube best suited for the process) has been estimated to have the potential to increase grid capacity by perhaps a million times. There are some serious obstacles to moving this technology from theory to production. These include consistent production of nanotubes with controlled and desirable conduction properties and improved understanding of transport across tube junctions.

**Alberta industry collaboration**

The AESO continuously monitors advancements in transmission technology to facilitate its application to the AIES. It also participates in efforts such as the Alberta Power Industry Consortium with the objective of promoting opportunities in power careers at the University of Alberta to enhance the longer-term supply of engineers in the electric utility profession. In addition to the AESO, the consortium also includes AltaLink Management Ltd., ATCO Electric Ltd., EPCOR and FortisAlberta Inc.

An example of the consortium’s work is its support of the Natural Sciences and Engineering Research Council of Canada/Informatics Circle of Research Excellence – Alberta Power Companies Industrial Research Chair in Power Quality at the University of Alberta. Dr. Wilson Xu was appointed to this Chair in early 2008. Dr. Xu is leading a team of researchers in using modern information and communication technologies to enhance performance of the AIES.

---

10 From Building Tomorrow’s Super Grid EnergyBiz Magazine, September/October 2006.
Appendix H

Ancillary Services Participant Manual
# Table of Contents

<table>
<thead>
<tr>
<th>Topic</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Who is the Alberta Electric System Operator?</td>
<td>2</td>
</tr>
<tr>
<td>Purpose of this Manual</td>
<td>4</td>
</tr>
<tr>
<td>Alberta and the Western Electricity Coordinating Council (WECC)</td>
<td>5</td>
</tr>
<tr>
<td>Alberta Reliability Standards</td>
<td>6</td>
</tr>
<tr>
<td>What are Ancillary Services?</td>
<td>7</td>
</tr>
<tr>
<td>Operating reserve</td>
<td>7</td>
</tr>
<tr>
<td>Transmission must-run service</td>
<td>7</td>
</tr>
<tr>
<td>Load shed service</td>
<td>7</td>
</tr>
<tr>
<td>Black start service</td>
<td>7</td>
</tr>
<tr>
<td>What is Operating Reserve?</td>
<td>8</td>
</tr>
<tr>
<td>Active and standby reserve</td>
<td>8</td>
</tr>
<tr>
<td>What is Regulating Reserve?</td>
<td>9</td>
</tr>
<tr>
<td>Regulating reserve technical requirements</td>
<td>9</td>
</tr>
<tr>
<td>What is Contingency Reserve?</td>
<td>10</td>
</tr>
<tr>
<td>Spinning reserve</td>
<td>10</td>
</tr>
<tr>
<td>Supplemental reserve</td>
<td>10</td>
</tr>
<tr>
<td>Spinning and supplemental technical requirements</td>
<td>11</td>
</tr>
<tr>
<td>Cost of Operating Reserve?</td>
<td>12</td>
</tr>
<tr>
<td>Who pays for Ancillary Services?</td>
<td>13</td>
</tr>
<tr>
<td>Operating Reserve Dispatches and Directives</td>
<td>14</td>
</tr>
<tr>
<td>Non-compliance with a Dispatch from the System Controller</td>
<td>16</td>
</tr>
<tr>
<td>Conscription of Operating Reserve</td>
<td>17</td>
</tr>
<tr>
<td>Dispatch Response Times</td>
<td>18</td>
</tr>
<tr>
<td>Regulating reserve</td>
<td>18</td>
</tr>
<tr>
<td>Spinning and supplemental reserve</td>
<td>18</td>
</tr>
<tr>
<td>Restrictions on Minimum and Maximum Volumes for Sale by Participants</td>
<td>19</td>
</tr>
<tr>
<td>Regulating reserve</td>
<td>19</td>
</tr>
<tr>
<td>Spinning reserve</td>
<td>19</td>
</tr>
<tr>
<td>Supplemental reserve</td>
<td>19</td>
</tr>
<tr>
<td>Operating Reserve Volume Requirements</td>
<td>20</td>
</tr>
<tr>
<td>Regulating reserve volume requirements</td>
<td>20</td>
</tr>
<tr>
<td>Contingency reserve (spinning and supplemental reserve) volume requires</td>
<td>22</td>
</tr>
<tr>
<td>Active and standby resource requirements</td>
<td>22</td>
</tr>
</tbody>
</table>
Procurement in the Operating Reserve Market 23
   Watt-Ex 23
   Over-the-counter (OTC) 23
   Timing of operating reserve procurement 23
   Shaped procurement 25
   Trade cancellations 27

Pricing in the Active Reserve Market – Watt-Ex 28

Pricing in the Active Reserve Market – Over-the-counter (OTC) 30
   The OTC process 30

Pricing in the Standby Reserve Market – Watt-Ex 34

Operating Reserve Settlement 35
   Exchange traded reserves (Watt-Ex) 35
   Over-the-counter contracts (OTC) 35

Internal Controls for Procurement of Operating Reserve 36

Transmission Must-Run (TMR) 37
   Classes of transmission must-run service 37
   Procurement of transmission must-run service 37
   Compensation for transmission must-run service 38
   Conscription of transmission must-run service 38

Load Shed Schemes 40
   Import load remedial action scheme (ILRAS) 40
   Load shed service (LSS) 40
   Technical requirements for load shed service providers 41
   Compensation for load shed service 41
   Proposed load shed service imports (LSSI) 42

Black start service 44
   Procurement of black start service 45
   Technical requirements for black start service providers 45
   Compensation for black start service 45
   Conscription of black start service 45

List of Applicable Operating Policies and Procedures (OPPs) 46

Glossary of Terms 49

Disclaimer

This Ancillary Services Participant Manual does not supersede or replace any ISO Rules, policies, procedures or guidelines that are currently in effect. In the event of any conflict between the Ancillary Services Participant Manual and the ISO Rules, policies, procedures or guidelines, the ISO Rules, policies, procedures or guidelines shall prevail.
Who is the Alberta Electric System Operator?

As an independent system operator, the Alberta Electric System Operator (AESO) leads the safe, reliable and economic planning and operation of Alberta's interconnected power system. The AESO also facilitates Alberta’s fair, efficient and openly competitive wholesale electricity market, which has about 200 participants and $5 billion (in 2009) in annual energy transactions.

The AESO is a non-profit organization, acting in the public interest of 3.5 million Albertans with a workforce of 400 employees. The AESO owns no assets and has no affiliation or financial investment of any kind in the electricity industry.

The AESO is governed by an independent board and regulatory oversight is provided by the Alberta Utilities Commission.

The AESO operates the grid to North American Electric Reliability Council and Western Electricity Coordinating Council (WECC) standards. As a WECC member, the AESO is part of an organization whose members represent the electric power systems involved in power generation and transmission systems serving the 14 western United States, British Columbia and Alberta.

The AESO keeps the lights on for all Albertans, ensuring safe, reliable, and economic electricity today – and in the future.
Operations – The AESO directs the coordinated operation of Alberta’s power grid on a 24 hour per day, seven day per week basis, dispatching energy to keep electricity supply and demand in perfect balance at all times and directing restoration activities in the event of a major system disturbance.

Markets – The AESO develops and operates Alberta’s real-time wholesale, energy-only electricity market. A market participant is defined as any body that supplies, generates, transmits, distributes, trades, exchanges, purchases or sells electricity, electric energy, electricity services or ancillary services.

Transmission – The AESO plans and develops the provincial transmission system and coordinates intertie development with neighboring jurisdictions. The AESO forecasts demand and strives to ensure the system is reinforced to ensure continued reliability and to keep pace with Alberta’s growing requirements for power. A reliable system facilitates the competitive energy-only market and encourages investment in new generation supply. The AESO provides system access services, connecting all types of generation (coal, gas, wind, biomass, solar) to the grid as well as connecting customers who consume electricity.

Customer Connections – The AESO ensures all customers seeking connection to the Alberta Interconnected Electric System are provided open and fair access. The connection process requires customers to complete all requirements at each step of a six stage process before progressing to the next stage of the process. Four parties are involved in connecting a project to the transmission system: the customer, the Transmission Facility Owner, the Alberta Utilities Commission and the AESO. Each party has various levels of involvement in different stages of the process.
Purpose of this Manual

This manual is intended to serve as a resource for market participants who currently provide, or who may in the future wish to provide ancillary services to the Alberta Electric System Operator (AESO). It includes a description and the purpose of each ancillary service used by the AESO, as well as an overview of technical requirements, procurement practices, and other helpful information.

For participants wishing to join the operating reserve market, please refer to the How to Join section on the AESO website.

As the Independent System Operator (ISO) for the jurisdiction of Alberta, the AESO is responsible for the safe, reliable and economic operation of the interconnected electric system and for facilitating a fair, efficient and openly competitive market for electricity. In order to carry out these responsibilities, the AESO is given authority through legislation to make ISO Rules, to adopt or make Reliability Standards, to establish Operating Policies and Procedures (OPPs) and to prepare an ISO Tariff. These documents are referred to as the AESO’s authoritative documents.

Authoritative documents are used by the AESO to communicate the binding and legal rights, requirements and obligations of market participants and of the AESO. Compliance with the requirements set out in authoritative documents is mandatory for both market participants and the AESO.

In each section of this manual, you will find references to pertinent authoritative documents. Rather than include the complete text of each authoritative document in this manual, at the appropriate place we have provided a link to the full document posted on the AESO website.

Participants are advised to read the full version of all referenced authoritative documents, including all relevant ISO rules, OPPs and technical requirements, in order to be fully aware of their content and obligations.

**OPPs (Operating Policies and Procedures)** describe how the AESO operates the Alberta Interconnected Electric System in a safe, reliable and economic manner. OPPs describe specific procedures to be followed by the AESO system controller including: dispatching the merit order; interconnection management; reserve management; system emergency and curtailments; and communication and technical standards.

OPPs explain how participants are to apply rules, and how the AESO applies any external regulated requirements received from organizations like the Western Electricity Coordinating Council and the North American Electric Reliability Council.
Alberta and the Western Electricity Coordination Council (WECC)

Through its interties to British Columbia (B.C.), Alberta has long been a member and active supporter of the **Western Electricity Coordinating Council (WECC)**. The largest of the North American Electric Reliability Council (NERC)’s eight regional councils, the WECC region encompasses an area of nearly 1.8 million square miles, stretching from Alberta and B.C. to northern Baja California, Mexico, and includes all or part of the 14 western United States in between.

The WECC was formed in 2002 to coordinate and promote electric system reliability in the western interconnection, to provide non-discriminatory transmission access and to support the efficient operating of power markets.

As defined in an operating agreement with the WECC, the AESO is accountable for maintaining sufficient volumes of operating reserve at all times, for fulfilling performance obligations and for honoring reserve sharing agreements with neighboring jurisdictions.

**Regions and Balancing Authorities (As of August 1, 2007)**
Alberta Reliability Standards

The AESO is in the second year of a two year process of adopting North American Electric Reliability Council (NERC) reliability standards as Alberta Reliability Standards. This important initiative contributes to the reliable operation of the Alberta electric system through the development of a more consistent set of standards essential to maintaining and improving the reliability of the North American electric grid.

The AESO’s approach to adopting reliability standards includes a detailed review of standards by subject matter experts and extensive stakeholder consultation. For each standard, the AESO makes a recommendation to the Alberta Utilities Commission (AUC) to adopt the standard, reject the standard, or adopt the standard with modifications appropriate for Alberta.

Alberta Reliability Standards contain information on the level of operating reserve the AESO is obligated to maintain in order to satisfy performance level criteria defined by the WECC.

Compliance with Alberta Reliability Standards by market participants as well as the AESO is a key element of system reliability. Under Section 23 of the Transmission Regulation (2009), the AESO is responsible for monitoring market participants’ compliance with reliability standards approved by the Alberta Utilities Commission.
What are Ancillary Services?

The Electric Utilities Act defines ancillary services as “those services required to ensure that the interconnected electric system is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency.”

The AESO uses a range of ancillary services provided by the generation (producers of energy) and load (consumers of energy) sides of the electricity system. Each type of ancillary service performs a unique function that supports the safe and reliable operation of the Alberta grid, as well as the neighboring jurisdictions to which the Alberta system is connected.

The types of ancillary services procured by the AESO are operating reserve, transmission must-run service, load shed scheme service and black start service. This manual contains sections dedicated to explaining in detail the purpose, procurement and pricing of each of these services:

**Operating reserve** – is available output from a generator that can be dispatched, or load that can be reduced, to maintain system reliability in the event of an imbalance between supply and demand on the electricity system. Operating reserve is further broken into regulating reserve and contingency reserve which are explained in the next section.

**Transmission must-run service** – is supplied by a generator that is required to be online and operating at specific levels in parts of the system where local transmission capacity is insufficient to meet local demand.

**Load shed scheme service** – is supplied by large electricity consumers (load) who have agreed with the AESO to be automatically tripped off (curtailed) in order to instantly reduce demand in the event of an unexpected problem that threatens the balance of supply and demand of electricity on the system.

**Black start service** – is supplied by generators that are able to restart their generation facility with no outside source of power. In the event of a system-wide blackout, black start providers are called upon to re-energize the transmission system by providing start-up power to generators who cannot self start.
What is Operating Reserve?

Because electricity can not be effectively stored and saved for when it is required, the supply of power must always be equal to the demand for power in Alberta’s electric system. To achieve this balance, the AESO constantly monitors the demand for electricity across the province and matches it with the available supply.

Operating reserve acts as a safety net, making extra power available to help instantaneously match supply and demand in real time, stabilizing and protecting the grid in the event of unforeseen problems affecting generating assets or transmission lines.

The extra power from operating reserve can come from unloaded or partially loaded generators or from load (large consumers of electricity) that can be curtailed.

Operating reserve is broken into two types: regulating reserve and contingency reserve. Contingency reserve is further separated into spinning and supplemental reserve (known in some jurisdictions outside Alberta as non-spinning reserve). Each type of reserve performs a unique function and has unique technical requirements.

**ACTIVE AND STANDBY RESERVE**

The AESO procures active and standby volumes of each type of the operating reserve described above. The terms active and standby are used to differentiate the timing and order of dispatch of these reserves by the system controller.

The purpose of active reserve is to meet the requirements of the electric system under normal operating conditions and is always dispatched first by the system controller.

The purpose of standby reserve is to provide additional reserve for use when the resources available in the active reserve portfolio are not sufficient to meet the real time operating and reliability requirements of the electric system. Standby reserve is dispatched after all the resources from the active reserve portfolio have been dispatched, or when providers of active operating reserve are, for some reason, unable to provide the volumes procured by the AESO.
What is Regulating Reserve?

The balance between supply and demand on the electric system is not instantaneous. Sometimes there is a lag while generation catches up to increased load, or while generation decreases in response to lower demand. Regulating reserve is used to provide the power needed to address that lag period between the balancing of supply and demand, as well as for voltage support.

Regulating reserve plays a critical role in maintaining the balance between generation and load within the Alberta control area, as well as ensuring Alberta’s interconnection with British Columbia is kept at the designated scheduled frequency of 60 Hz. Regulating reserve is provided by partially loaded, synchronized generators able to immediately respond to automatic generation control (AGC) signals from the AESO system coordination centre.

Generators providing regulating reserve must be controlled by an AGC system that adjusts generator output levels within the generator’s established regulation range. This technical requirement enables the generator to compensate for moment-to-moment changes in load and generation on the system. The AESO controls the AGC of generators who supply regulating reserve. The AESO system controller monitors electricity frequency across the province and sends signals to each AGC to move up or down as required.

AGC performance is monitored through the use of the North American Electric Reliability Council (NERC) control performance standards, as defined in Alberta Reliability Standard BAL-001.

In order to provide regulating reserve, generators must satisfy specific technical requirements. These requirements are described in the technical requirement document on the AESO website.

Please click here to view the Regulating Reserve Technical Requirements or visit the AESO website at www.aeso.ca and follow the path Market > Ancillary Services > Operating Reserves > Technical Requirements.

**OPP 401 Regulating Reserve Service**

As a member of the Western Electricity Coordinating Council, the AESO is required to carry sufficient operating reserve. The criteria for determining minimum operating reserve (contingency reserve plus regulating reserve) are established by the WECC. The AESO has an obligation to procure regulating reserve from the ancillary service exchange or by other means. The system controller may be required to adjust the volume of regulating reserve in real time based on actual system conditions.
What is Contingency Reserve?

Contingency reserve is used to restore the balance of supply and demand of electricity following a contingency or unforeseen event threatening the reliable operation of the electric system. Unexpected contingencies can include events such as the sudden loss of a generator, an unanticipated increase in demand, disruption to one of Alberta’s interties linking Alberta to a neighboring jurisdiction, or damage to a major transmission line.

Contingency reserve is extra backup power that carries the stringent requirement of being able to deliver power to the grid within ten minutes of a loss on the system. This type of reserve can be provided by the supply side of the system (generators willing to supply power) and the demand side of the system (large electricity consumers willing to reduce their demand on the system in response to a directive from the AESO’s system controller).

There are two types of contingency reserve:

**Spinning reserve** is the fastest responding type of contingency reserve. Generators providing spinning reserve must be synchronized to the grid. This means the generator’s turbine is spinning but not generating power, and is able to quickly begin supplying power in response to a directive from the AESO system controller. Spinning reserve also provides frequency support to the electric system.

**Supplemental reserve** is generating capacity or load that is not required to be synchronized to the grid, but can provide power within 10 minutes in either of two ways when called upon by the system controller: Generators would increase their output to the system and load (consumers of electricity) would reduce their demand on the system.

Supplemental reserve is similar to spinning reserve except that providers of supplemental reserve are not required to respond to frequency deviations. Therefore, supplemental reserve can be supplied by load as well as generators. Note that while load can provide supplemental reserve, it cannot provide spinning reserve.
The criteria for determining contingency reserve levels on the Alberta system are established by the Western Electricity Coordinating Council and the North West Power Pool Reserve Sharing Group. The amount of energy required can vary according to system conditions and Alberta Reliability Standards require that at least 50 per cent of total contingency reserve must be spinning reserve.

**OPP 402 Supplemental and Spinning Reserve Services**

Defines the contingency reserve criteria for the Alberta Interconnected Electrical System and provides guidelines and procedures for the system controller to dispatch assets for these reserves and to issue an ancillary service directive for the delivery of supplemental and spinning reserve energy.

**OPP 403 External Spinning and Supplemental Reserves from B.C.**

As a member of the Western Electricity Coordinating Council, the AESO is required to adhere to WECC’s Minimum Operating Reliability Criteria (MORC) which includes the requirement that balancing authorities maintain a minimum level of contingency reserve. To fulfill this requirement, the AESO must enter into an agreement with an ancillary service provider outside of the Alberta balancing authority to provide the Alberta Interconnected Electric System with an external source for spinning reserve and/or external supplemental reserve.

In order to provide spinning and supplemental reserve, generators must satisfy specific technical requirements. These requirements are described in the technical requirement document on the AESO website.

Please [click here](#) to view the Spinning and Supplemental Reserve Technical Requirements or visit the AESO website at www.aeso.ca and follow the path Market > Ancillary Services > Operating Reserves > Technical Requirements.
Cost of Operating Reserve

The price paid to providers of operating reserve is indexed to the pool price. Therefore, the total cost of operating reserve fluctuates from year to year.

Operating reserve costs to the AESO in 2009 were $101.9 million, which is $160.3 million or 61 per cent lower than the 2008 costs of $262.1 million, primarily due to lower hourly pool prices in 2009. For comparison, the average hourly pool price was $48 per megawatt hour (MWh) in 2009, compared to $90 per MWh in 2008, representing a decrease of 47 per cent. Operating reserve volumes were 8,116 GWh in 2009 compared to 8,139 GWh in 2008.

Table 1

<table>
<thead>
<tr>
<th>Year</th>
<th>Pool Price ($/MWh)</th>
<th>Operating Reserve Cost ($ Millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005</td>
<td>70.36</td>
<td>122.3</td>
</tr>
<tr>
<td>2006</td>
<td>80.79</td>
<td>183</td>
</tr>
<tr>
<td>2007</td>
<td>66.95</td>
<td>180.7</td>
</tr>
<tr>
<td>2008</td>
<td>89.95</td>
<td>262.1</td>
</tr>
<tr>
<td>2009</td>
<td>47.81</td>
<td>101.9</td>
</tr>
</tbody>
</table>

Figure 1: Annual Total Cost of Operating Reserve vs. Annual Average Pool Price: 2005 – 2009
Who pays for Ancillary Services?

In accordance with section 47(a)(i) of the Transmission Regulation, the costs of ancillary services, including operating reserve are paid for by load customers. The mechanism the AESO uses to recover these costs from load customers is the tariff, which is filed for approval with the Alberta Utilities Commission. In the tariff, costs for ancillary services are identified in the rate component applicable to load customers and broken out in the following charges:

- The operating reserve charge recovers costs associated with regulating, spinning, and supplemental reserve (both active and standby) and with some miscellaneous ancillary services where the cost varies with pool price;
- The voltage control charge recovers costs associated with the provision of transmission must-run services; and
- The other system support services charge recovers costs associated with some miscellaneous ancillary services where the cost does not vary with pool price.

The operating reserve charge makes up the largest part of ancillary services costs recovered. The TMR expense is the next largest expense and the other system support services charges represent the smallest charge.

Table 2

<table>
<thead>
<tr>
<th></th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating reserve costs</td>
<td>122.3</td>
<td>183</td>
<td>180.7</td>
<td>262.1</td>
<td>101.9</td>
</tr>
<tr>
<td>Transmission must-run (TMR) costs</td>
<td>56.4</td>
<td>41.3</td>
<td>45.6</td>
<td>41.8</td>
<td>26.0</td>
</tr>
<tr>
<td>Other ancillary services costs</td>
<td>11.1</td>
<td>10.9</td>
<td>9.5</td>
<td>8.0</td>
<td>6.4</td>
</tr>
<tr>
<td>Total ancillary services costs</td>
<td>189.8</td>
<td>235.2</td>
<td>235.8</td>
<td>311.9</td>
<td>134.3</td>
</tr>
</tbody>
</table>
Operating Reserve
Dispatches and Directives

The AESO system controller operates much like an air traffic controller, using sophisticated
data capture and analysis tools to monitor Alberta’s Interconnected Electric System on a
24 hour per day, seven day per week basis. In addition to balancing supply and demand in real
time, the system controller is responsible for all outage coordination, short and long term
operational planning, and working collaboratively with Transmission Facility Owners and
Emergency Management Alberta on system restoration activities to ensure that in the event of
a major disruption to service, normal operations can be quickly restored with minimal disruption
to all Albertans.

The system controller’s primary means of communicating with participants in the operating
reserve market is the Automated Dispatch and Messaging System (ADaMS). Should the ADaMS
ever be unavailable, the secondary means of communication between the system controller
and participants is telephone.

The system controller uses a two step process to contact providers of operating reserve:

1. The system controller sends an **ancillary services dispatch** to notify the participant
to free up capacity on their resource so that they can be ready to provide energy to
the grid. The dispatch will contain the following information for spinning, supplemental
and regulating reserve: the asset, type of reserve, the amount of MW to be supplied,
and the date and time the dispatch will take effect.

If a generator is outputting power at full capacity in the energy market and receives an
operating reserve dispatch, the AESO system controller issues a dispatch down
(reduce) instruction to the generator, telling the generator to reduce its generation in
the energy market by the level of MWs indicated in the operating reserve dispatch.
This freed up capacity can now be called upon if required by the system controller,
through the second step, an operating reserve directive.

For regulating reserve, the freed up capacity is the regulating reserve range. The unit
will provide energy within that range as directed by the AGC.

If, when the generator receives a dispatch it is NOT operating at full output and has
capacity available on its unit, then no action by the participant is required in the
energy market.
2a. **Ancillary services directive** is the second step of the process and follows an ancillary services dispatch. It is an instruction by the system controller to a participant to provide all or some of the volume of capacity dispatched as energy (directed volume). The directed volume must be supplied by the participant as energy within 10 minutes of receiving a directive.

Please refer to the **Ancillary Services Technical Requirements** for a detailed explanation of the dispatch and directive obligations of participants.

The system controller is required to restore the reserve capacity within one hour. Therefore, within one hour of issuing a directive, the system controller will either issue the participant a dispatch or notify the participant that they are no longer required to provide the energy requested in the directive.

The rationale behind this process is that if energy is still required after an hour, it should be supplied by the energy market, as opposed to the ancillary services market. In the rare case where after one hour the energy is still required, the system controller would dispatch off the unit and either re-direct them on or direct a different participant’s unit on.

2b. **Ancillary Services Directive – Regulating Reserve**

For regulating reserve, the controller does not issue a directive to the unit. Regulating reserve providers are controlled by an AGC unit, therefore, after a dispatch is issued, the freed up space is the regulating range and the generating unit will provide energy within that range as directed by AGC commands.
Non-compliance with a Dispatch from the System Controller

The participant may decline a dispatch from the system controller, but must restate the new capability of the asset to provide operating reserve in a timely manner and provide reasons for declining the dispatch.

The AESO evaluates whether or not the reason(s) for declining an operating reserve dispatch are acceptable. If the reason is deemed unacceptable by the AESO, the participant will be considered non-compliant and may be subject to pay liquidated damages.

There are two ways a participant can fail to fulfill their contractual obligation to provide operating reserve (non-compliance):

1. First, if after contracting to provide reserve, and prior to the delivery hour, the provider restates some or all of the commitment, then they have failed to fulfill their obligation.
2. Second, if the provider is dispatched to provide reserve during the delivery hour and they are deemed to have not fully provided the contracted amount, then they have failed to fulfill their obligation.

This act of non-compliance can result in a number of repercussions including clawback of payment to the provider by the AESO for the reserve during the hour in question, assessment of liquidated damages (which recovers the AESO’s incremental costs as a result of the participant’s non-performance), and possible pursuit of the event as a contravention of the ISO rules.

In the event of non-compliance, the AESO’s compliance department will assess liquidated damages payable by the participant.

When failure to comply with a dispatch is as a result of an event of force majeure (as defined in the relevant contract) and the participant notifies the AESO within two business days of the occurrence, then both liquidated damages and pursuit as an ISO rule contravention may be waived. However, payment will still be clawed back for the portion of the service not provided.

The definition of force majeure includes operational problems that are beyond the control of the participant and which could not have been avoided through reasonable diligence.
Conscription of Operating Reserve

Conscription of non-contracted operating reserve has historically only been required by the AESO approximately five days each year, typically for a duration of one to two hours and only when all contracted operating reserve has been dispatched. Should the system controller deem this out of market action to be necessary, the conscripted generator would be compensated according to the terms of the Tariff (under “Directed Ancillary Services other than Transmission must-run services”).

For more information on payment for conscription of operating reserve please refer to the current tariff on the AESO website.
Dispatch Response Times

REGULATING RESERVE

Because of the critical role regulating reserve plays in maintaining voltage support to the electric system, participants providing this type of reserve are required to adhere to strict requirements established by the AESO.

When a participant receives a regulating reserve dispatch, within 15 minutes they must prepare their generator to provide the reserve and be ready to accept control signals from the AGC master controller.

During normal AGC operation, the master controller issues two types of control signals: raise and lower signals. A raise signal may follow a previous raise signal, and similarly, a lower signal may follow a previous lower signal. Control signals may also include reversals, where a raise signal follows a lower signal or a lower signal follows a raise signal. The AGC master controller may issue reversals as often as every four seconds.

For full details of this information refer to Technical Requirements for Provision of Regulating Reserves on the AESO website.

SPINNING AND SUPPLEMENTAL RESERVE

The dispatch response requirements for spinning and supplemental reserve are identical with the exception that although load can provide supplemental reserve, it is ineligible to provide spinning reserve.

When the system controller sends an ancillary service dispatch to a participant requesting them to activate a volume of spinning or supplemental reserve, within fifteen minutes the provider must position the real power of the resource (generator or load) to supply the dispatched volume.

When the system controller sends an ancillary service directive to a provider instructing them to deploy a volume of spinning or supplemental reserve, the provider must deliver the full directed power within ten minutes.

For full details of this information refer to Technical Requirements for Ancillary Services on the AESO website.
Restrictions on Minimum and Maximum Volumes for Sale by Participants

The maximum volume any provider can offer in an ancillary service contract from the same facility for the same hour is 80 MW. An exception to this restriction is where hydro or thermal generating facilities have multiple independent units listed under one facility name. The minimum volume each provider must provide is five MW. However, to qualify as a provider, the following requirements apply:

**REGULATING RESERVE**
To qualify as a provider of regulating reserve, the provider must initially be able to provide a minimum of 15 MW of regulating reserve. After qualifying to become a provider, they then have the option of selling five MW or a greater volume.

**SPINNING RESERVE**
To qualify as a provider of spinning reserve, the provider must initially be able to provide a minimum of 10 MW of this reserve. After qualifying to become a provider, they then have the option of selling five MW or a greater volume.

**SUPPLEMENTAL RESERVE**
To qualify as a provider of supplemental reserve, the provider must initially be able to provide a minimum of five MW of this reserve. After qualifying to become a provider, they then can have the option of selling five MW or a greater volume.
Operating Reserve Volume Requirements

As referenced earlier in this manual, the Western Electricity Coordinating Council sets the performance standards for all the balancing authorities within the WECC. Each balancing authority must procure operating reserve to meet these standards.

**REGULATING RESERVE VOLUME REQUIREMENTS**

The AESO’s requirement for regulating reserve is influenced primarily by changes to intertie schedules and the short-term Alberta Internal Load forecast. Only generators equipped with approved automatic generator control (AGC) capability can supply regulating reserve to the AESO.

Regulating reserve volumes available to the system controller must meet both NERC and WECC Control Performance Criteria (CPS1 and CPS2) for the Alberta Interconnected Electric System control area.

These Control Performance Standards set limits on area control error (ACE) variation to ensure system frequency is maintained within acceptable limits over varying periods of time.

The current daily regulating reserve requirement for the Alberta electric system ranges from a minimum of 110 MW to a maximum of 225 MW. This range has been established to address the single largest load variability in the province. The hourly range of regulating reserve is shown in Table 3 on the next page, taken from OPP 401. The values displayed also align with the transmission reliability margin on the B.C. intertie.

**OPP 401 Regulating Reserve Service**

As a member of the Western Electricity Coordinating Council, the AESO is required to carry sufficient operating reserve. The criteria for determining minimum operating reserve (contingency reserve plus regulating reserve) are established by the WECC. The AESO has an obligation to procure regulating reserve from the ancillary service exchange or by other means. The system controller may be required to adjust the volume of regulating reserve in real time based on actual system conditions.
### Table 3: Regulation Range Guidelines

<table>
<thead>
<tr>
<th>Time Period (Hour Ending)</th>
<th>Minimum Regulation Range (MW)</th>
<th>Maximum Regulation Range (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>110</td>
<td>175</td>
</tr>
<tr>
<td>2</td>
<td>110</td>
<td>175</td>
</tr>
<tr>
<td>3</td>
<td>110</td>
<td>175</td>
</tr>
<tr>
<td>4</td>
<td>110</td>
<td>175</td>
</tr>
<tr>
<td>5</td>
<td>110</td>
<td>175</td>
</tr>
<tr>
<td>6</td>
<td>110</td>
<td>225</td>
</tr>
<tr>
<td>7</td>
<td>110</td>
<td>225</td>
</tr>
<tr>
<td>8</td>
<td>110</td>
<td>225</td>
</tr>
<tr>
<td>9</td>
<td>110</td>
<td>225</td>
</tr>
<tr>
<td>10</td>
<td>110</td>
<td>175</td>
</tr>
<tr>
<td>11</td>
<td>110</td>
<td>175</td>
</tr>
<tr>
<td>12</td>
<td>110</td>
<td>175</td>
</tr>
<tr>
<td>13</td>
<td>110</td>
<td>175</td>
</tr>
<tr>
<td>14</td>
<td>110</td>
<td>175</td>
</tr>
<tr>
<td>15</td>
<td>110</td>
<td>175</td>
</tr>
<tr>
<td>16</td>
<td>110</td>
<td>175</td>
</tr>
<tr>
<td>17</td>
<td>110</td>
<td>225</td>
</tr>
<tr>
<td>18</td>
<td>110</td>
<td>225</td>
</tr>
<tr>
<td>19</td>
<td>110</td>
<td>225</td>
</tr>
<tr>
<td>20</td>
<td>110</td>
<td>225</td>
</tr>
<tr>
<td>21</td>
<td>110</td>
<td>225</td>
</tr>
<tr>
<td>22</td>
<td>110</td>
<td>225</td>
</tr>
<tr>
<td>23</td>
<td>110</td>
<td>225</td>
</tr>
<tr>
<td>24</td>
<td>110</td>
<td>225</td>
</tr>
</tbody>
</table>

Regulating reserve requirements also take into consideration system ramps, load fluctuations and the ramping capability of the Energy Market Merit Order, however they do not currently consider wind power variability.
CONTINGENCY RESERVE (SPINNING AND SUPPLEMENTAL RESERVE)

VOLUME REQUIREMENTS

The criteria for determining contingency reserve volume levels are established by the WECC and the Northwest Power Pool Reserve Sharing Group and vary depending on system conditions. The reserve sharing and contingency reserve requirements are outlined in OPP 402 and OPP 405. The AESO is obliged to comply with reserve level requirements and may be subject to sanctions if the WECC criteria are violated.

OPP 402 Supplemental and Spinning Reserve Services

This OPP defines the contingency reserve criteria for the Alberta Interconnected Electrical System and provide guidelines and procedures for the system controller in dispatching assets for supplemental and spinning reserve and in issuing an ancillary service directive for the delivery of supplemental and spinning reserve energy.

OPP 405 Automated Northwest Power Pool Contingency Reserve Sharing

This OPP defines the policies and procedures the System Controller must use to respond to or initiate a Northwest Power Pool Contingency Reserve obligation request either through the automated Pro-Rata Reserve Sharing system or via telephone when the system is unavailable.

ACTIVE AND STANDBY RESERVE REQUIREMENTS

As discussed, the AESO procures active and standby volumes for each type of operating reserve.

The purpose of active reserve is to meet the requirements of the electric system under normal operating conditions and is always dispatched first by the system controller. The purpose of standby reserve is to provide additional reserve for use when the resources available in the active portfolio are not sufficient to meet the real time operating and reliability requirements of the electric system.

Standby reserve is procured by the AESO in order to satisfy a WECC criteria requirement. The AESO voluntarily buys a volume of standby reserve to ensure the reliable operation of Alberta’s electric system.

The goal of the forecast is to ensure sufficient standby reserve is available so that no reasonable outages or loss of spinning or supplemental reserve will require the conscription of non-contract reserve.
Procurement in the Operating Reserve Market

The AESO’s objective is to procure operating reserve in a transparent, competitive, and well-documented manner. In the current structure of Alberta’s electricity market, the AESO is the sole buyer of operating reserve.

Each day the AESO procures operating reserve (including regulating reserve, spinning reserve and supplemental reserve) for the Alberta market from generators and loads through two different but equally important platforms: Watt-Ex, an online exchange and over-the-counter (OTC) contracts for volumes that cannot be procured through Watt-Ex.

**WATT-EX**

The Watt-Ex platform is an online exchange operated by a for-profit third party clearing house. The exchange offers complete transparency of all transactions to all participants, but allows sellers to remain anonymous to one another and to the buyer.

**OVER-THE-COUNTER (OTC)**

Over-the-counter contracts are used to procure operating reserve volume not procured on the Watt-Ex platform. Each trading day, after the Watt-Ex market has closed, the AESO issues an email to all registered OTC participants informing them of the remaining requirements for each operating reserve product for each hour. Sellers send back their offers to the AESO, and the AESO stacks the volumes from lowest to highest price and enters into contracts with the sellers accordingly.

**TIMING OF OPERATING RESERVE PROCUREMENT**

Operating reserve is procured one day in advance of when it is required. This timing is referred to as “day minus one” or “D-1”. Prior to July 2010, operating reserve was procured up to five days in advance of delivery. However, this was reduced to D-1 procurement after July 2010 as part of the AESO’s ongoing efforts to improve the design of the operating reserve market.
The operating reserve market is closed on weekends and holidays, therefore D-1 procurement for the weekend (Saturday, Sunday and Monday) takes place on Friday. Since the market is closed on Sunday, Monday is included in the weekend.

**D-1 Schedule:**

- On Monday: D-1 is Tuesday
- On Tuesday: D-1 is Wednesday
- On Wednesday: D-1 is Thursday
- On Thursday: D-1 is Friday
- On Friday: D-1 is Saturday, Sunday and Monday

On holidays D-1 is the last business day before the holiday. If a holiday occurs in conjunction with a weekend, then operating reserve for the holiday is procured in addition to the weekend.

**D-1 Holiday Schedule – Holiday not attached to the weekend:**

- Tuesday is the Holiday
  - On Monday: D-1 is Tuesday and Wednesday (Tuesday is a holiday, Monday is the last business day before the holiday)
  - On Tuesday: Market closed
  - On Wednesday: D-1 is Thursday
  - On Thursday: D-1 is Friday
  - On Friday: D-1 is Saturday, Sunday and Monday

**D-1 Holiday Schedule – Holiday attached to the weekend:**

- Monday is the Holiday
  - On Friday: D-1 is Saturday, Sunday, Monday, and Tuesday
  - On Monday: Market closed
  - On Tuesday: D-1 is Wednesday
  - On Wednesday: D-1 is Thursday
  - On Thursday: D-1 is Friday
  - On Friday: D-1 is Saturday, Sunday, Monday

The operating reserve volumes purchased on D-1 are determined by the **Seven Day Forecast of Operating Reserve Volumes** on the ETS section of the AESO website under Current Reports. This report estimates the volume of reserve the AESO anticipates will be required for each given day, seven days forward from the current day. The forecast is updated daily and the volumes procured each day can change according to the forecast.

**General daily timeline for the procurement of operating reserve:**

- 9:00 a.m. – 10:30 a.m. D-1 operating reserve is procured through Watt-Ex. Procurement through Watt-Ex closes at 10:30 a.m.
- 10:30 a.m. – Noon Any operating reserve required for the next day not procured through Watt-Ex is then procured through OTC
SHAPED PROCUREMENT

The AESO’s approach to buying operating reserve is described as shaped (or profiled) procurement. Using shaped procurement allows the AESO to procure active reserve volumes to the exact MW forecast, recognizing that a different volume of reserve is forecast and procured in each hour. On peak (hours ending 8-23) and off peak (hours ending 1-7 and 24) are procured separately.

Because Watt-Ex requires the volume of reserve purchased to be the same for all on peak and off peak hours, shaped procurement relies on the use of over-the-counter contracts that allow the AESO to purchase specific volumes of reserve for each hour. For this reason, Watt-Ex is used to procure the minimum forecast volume in any given on peak or off peak period and OTC is used to procure the remaining hourly volume requirements.

Table 4: Seven-day Forecast of Operating Reserves Volumes (MW)
(Forecast updated daily, by 9:00 a.m.)

<table>
<thead>
<tr>
<th>Date</th>
<th>HE</th>
<th>Active Regulating</th>
<th>Active Spinning</th>
<th>Active Supplemental</th>
<th>Standby Regulating</th>
<th>Standby Spinning</th>
<th>Standby Supplemental</th>
</tr>
</thead>
<tbody>
<tr>
<td>02/26/2010</td>
<td>1</td>
<td>128</td>
<td>244</td>
<td>244</td>
<td>130</td>
<td>105</td>
<td>35</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>2</td>
<td>125</td>
<td>241</td>
<td>241</td>
<td>130</td>
<td>105</td>
<td>35</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>3</td>
<td>135</td>
<td>239</td>
<td>239</td>
<td>130</td>
<td>105</td>
<td>35</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>4</td>
<td>135</td>
<td>238</td>
<td>238</td>
<td>130</td>
<td>105</td>
<td>35</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>5</td>
<td>139</td>
<td>240</td>
<td>240</td>
<td>130</td>
<td>105</td>
<td>35</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>6</td>
<td>225</td>
<td>245</td>
<td>245</td>
<td>130</td>
<td>105</td>
<td>35</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>7</td>
<td>225</td>
<td>255</td>
<td>255</td>
<td>130</td>
<td>105</td>
<td>35</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>8</td>
<td>150</td>
<td>261</td>
<td>261</td>
<td>130</td>
<td>105</td>
<td>45</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>9</td>
<td>165</td>
<td>263</td>
<td>263</td>
<td>130</td>
<td>105</td>
<td>45</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>10</td>
<td>150</td>
<td>264</td>
<td>264</td>
<td>130</td>
<td>105</td>
<td>45</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>11</td>
<td>150</td>
<td>266</td>
<td>266</td>
<td>130</td>
<td>105</td>
<td>45</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>12</td>
<td>150</td>
<td>266</td>
<td>266</td>
<td>130</td>
<td>105</td>
<td>45</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>13</td>
<td>145</td>
<td>266</td>
<td>266</td>
<td>130</td>
<td>105</td>
<td>45</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>14</td>
<td>145</td>
<td>265</td>
<td>265</td>
<td>130</td>
<td>105</td>
<td>45</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>15</td>
<td>145</td>
<td>263</td>
<td>263</td>
<td>130</td>
<td>105</td>
<td>45</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>16</td>
<td>150</td>
<td>262</td>
<td>262</td>
<td>130</td>
<td>105</td>
<td>45</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>17</td>
<td>150</td>
<td>261</td>
<td>261</td>
<td>130</td>
<td>105</td>
<td>45</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>18</td>
<td>170</td>
<td>263</td>
<td>263</td>
<td>130</td>
<td>105</td>
<td>45</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>19</td>
<td>180</td>
<td>264</td>
<td>264</td>
<td>130</td>
<td>105</td>
<td>45</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>20</td>
<td>180</td>
<td>264</td>
<td>264</td>
<td>130</td>
<td>105</td>
<td>45</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>21</td>
<td>175</td>
<td>262</td>
<td>262</td>
<td>130</td>
<td>105</td>
<td>45</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>22</td>
<td>177</td>
<td>259</td>
<td>259</td>
<td>130</td>
<td>105</td>
<td>45</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>23</td>
<td>187</td>
<td>254</td>
<td>254</td>
<td>130</td>
<td>105</td>
<td>45</td>
</tr>
<tr>
<td>02/26/2010</td>
<td>24</td>
<td>125</td>
<td>248</td>
<td>248</td>
<td>130</td>
<td>105</td>
<td>35</td>
</tr>
</tbody>
</table>
In Table 4, the minimum forecast volume for spinning reserve in the off peak hours is 254 MW. The on peak hour with the minimum volume forecast (254 MW) is HE23 and the requirements for all the other remaining on peak hours are forecast to be greater than 254 MW. Therefore, the AESO will procure only 254 MW of spinning reserve for each of the on peak hours on Watt-Ex.

This difference is procured using OTC contracts. In the example above, the following volumes are procured through OTC contracts:

<table>
<thead>
<tr>
<th>HE</th>
<th>MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>8</td>
<td>7</td>
</tr>
<tr>
<td>9</td>
<td>9</td>
</tr>
<tr>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>11</td>
<td>12</td>
</tr>
<tr>
<td>12</td>
<td>12</td>
</tr>
<tr>
<td>13</td>
<td>12</td>
</tr>
<tr>
<td>14</td>
<td>11</td>
</tr>
<tr>
<td>15</td>
<td>9</td>
</tr>
<tr>
<td>16</td>
<td>8</td>
</tr>
<tr>
<td>17</td>
<td>7</td>
</tr>
<tr>
<td>18</td>
<td>9</td>
</tr>
<tr>
<td>19</td>
<td>10</td>
</tr>
<tr>
<td>20</td>
<td>10</td>
</tr>
<tr>
<td>21</td>
<td>8</td>
</tr>
<tr>
<td>22</td>
<td>5</td>
</tr>
<tr>
<td>23</td>
<td>0</td>
</tr>
</tbody>
</table>

Table 5: Summary of operating reserve procurement practices

<table>
<thead>
<tr>
<th>Day</th>
<th>D-1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Time of Day</td>
<td>Morning</td>
</tr>
<tr>
<td>Platform</td>
<td>Watt-Ex OTC</td>
</tr>
<tr>
<td>Commodity</td>
<td>Active, Standby</td>
</tr>
<tr>
<td>Products</td>
<td>Regulating, Spinning, Supplemental</td>
</tr>
<tr>
<td>Hours</td>
<td>On peak and Off peak</td>
</tr>
<tr>
<td>Procurement Volume(s)</td>
<td>Active on peak: Least volume hour procured for all hours</td>
</tr>
<tr>
<td></td>
<td>Active off peak: Least volume hour procured for all hours</td>
</tr>
<tr>
<td></td>
<td>Standby: All required volumes</td>
</tr>
</tbody>
</table>
D-1 markets on Watt-Ex close sequentially for each reserve product. The active reserve market closes first, followed by closure of the standby reserve market. Reserves in the active reserve market close in this order: Active regulating reserve closes first, active spinning reserve closes second and active supplemental reserve closes last.

Following the closure of the active reserve market, reserves in the standby reserve market close in this order: Standby regulating reserve closes first, standby spinning reserve closes second and standby supplemental reserve closes last.

**Closing Time for Each Market in D-1**
- 9:40 a.m. Active regulating reserve closes
- 9:50 a.m. Active spinning reserve closes
- 10:00 a.m. Active supplemental reserve closes
- 10:10 a.m. Standby regulating reserve closes
- 10:20 a.m. Standby spinning reserve closes
- 10:30 a.m. Standby supplemental reserve closes

The order of market closure is related to the technical requirements for each product. Regulating reserve has the strictest technical requirements and is therefore the highest value product. Supplemental reserve has the least restrictive technical requirements and is therefore the lowest value product.

The sequential closing of the market ensures that if a participant fails to sell all of their highest value product (e.g., regulating reserve), they will have an opportunity to sell any remaining capacity in the other product markets (e.g., spinning reserve, then supplemental reserve).

**TRADE CANCELLATIONS**

A trade cancellation can occur in the active market for any product as outlined in the Watt-Ex agreement.

For full details of this information refer to the **Watt-Ex** website under Watt-Ex Agreement – Trade Cancellations.
Pricing in the Active Reserve Market – Watt-Ex

When buying active reserve, the AESO bids for a volume of reserve defined as either on peak (i.e. hours ending 8 to 23) or off peak (all other hours), at a price that is discounted (lower) or at a premium (higher) than the pool price.

Participants submit their price and volume offers into the market for each product at a discount or a premium to the pool price, referred to as indexing to the pool price. When the market closes, the last offer that satisfies the amount of volume required is the marginal or clearing offer, and all offers that are better than or above the offer at the margin receive the marginal offer price.

When the reserve offered by a participant is dispatched by the system controller, the participant is paid the pool price plus the equilibrium price (see formula below). The equilibrium price is the average of the AESO bid price and the marginal offer.

When the system controller directs a participant to provide the energy offered for a reserve, the participant is paid the current pool price for the energy they are providing in addition to the payment they receive for providing the reserve.

Also known as the trade price, the equilibrium price is the average of the bid price and the marginal offer.

\[
\text{Equilibrium Price} = \frac{(\text{Bid} + \text{Marginal Offer})}{2}
\]

For an equilibrium price of $X, the AESO pays (pool price – $X) times volume for every hour the pool price is greater than $X. In the event that the equilibrium price of $X exceeds the pool price, the price received by the seller is zero. The seller is not required to pay the AESO if pool price – $X is negative.
The general process for trading on Watt-Ex is illustrated in this example:

On D-1 the AESO needs to buy 100 MW of on peak spinning reserve and the AESO’s bid price is $10. Here are the offers:

<table>
<thead>
<tr>
<th>Offer</th>
<th>MW</th>
<th>Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Offer 1</td>
<td>10MW</td>
<td>-$10</td>
</tr>
<tr>
<td>Offer 2</td>
<td>30MW</td>
<td>-$5</td>
</tr>
<tr>
<td>Offer 3</td>
<td>40MW</td>
<td>$0</td>
</tr>
<tr>
<td>Offer 4</td>
<td>10MW</td>
<td>$5</td>
</tr>
<tr>
<td>Offer 5</td>
<td>10MW</td>
<td>$10</td>
</tr>
<tr>
<td>Offer 6</td>
<td>25MW</td>
<td>$15</td>
</tr>
<tr>
<td>Offer 7</td>
<td>30MW</td>
<td>$20</td>
</tr>
</tbody>
</table>

(Pool Price minus $10)  (Pool Price minus $5)  (Pool Price plus $0)  (Pool Price plus $5)  (Pool Price plus $10)  (Pool Price plus $15)  (Pool Price plus $20)

In this example the marginal offer is offer # 5 ($10) because it is the last offer, when combined with offers 1, 2, 3 and 4, that makes up the volume of 100 MW required by the AESO. The bid is the maximum price the AESO is willing to pay for the reserve ($10). The equilibrium price is then calculated as the average of the AESO’s bid and the marginal offer. In this example the equilibrium price would be ($10 + $10)/2 = $10.

The equilibrium price is then used to calculate the payment made to reserve providers. All providers receive the equilibrium price plus the hourly pool price for the period they are providing reserve.

In our example the reserve provider (seller) would receive, for each hour, the hourly average pool price plus $10. The amount the seller receives is referred to as the settlement price.

Operating Reserve Market Terminology

<table>
<thead>
<tr>
<th>Term</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Delivery Day</td>
<td>date reserve to be provided</td>
</tr>
<tr>
<td>Trade Date</td>
<td>date of transaction</td>
</tr>
<tr>
<td>Product</td>
<td>regulating, spinning or supplemental reserve</td>
</tr>
<tr>
<td>Commodity</td>
<td>active or standby</td>
</tr>
</tbody>
</table>
Pricing in the Active Reserve Market – Over-the-counter (OTC)

Similar to the Watt-Ex payment, OTC payments are indexed to pool price. However, unlike Watt-Ex, where providers are paid the pool price plus the equilibrium price, OTC payments are simply calculated by adding the pool price and the participant’s offer.

\[
\text{Over-the-counter price paid} = \text{Pool price} + \text{OTC offer}
\]

Unlike the Watt-Ex process, the AESO does not provide a bid price for OTC. Instead, participants simply provide an offer price for reserve and the AESO accepts or rejects the offer.

**THE OTC PROCESS**

OTC contracts are only used to procure D-1 volumes not procured through the Watt-Ex platform. Upon closure of the Watt-Ex market, the AESO sends an email to all registered OTC participants with a request for the remaining required volumes of reserve. Participants (if they choose to participate) then respond to the AESO with offers for specific amounts of volume at a certain price.
All registered OTC participants are provided an offer template they must use to offer reserve to the AESO.

<table>
<thead>
<tr>
<th>Delivery Date</th>
<th>06-May</th>
<th>06-May</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type</td>
<td>ACTIVE</td>
<td>ACTIVE</td>
</tr>
<tr>
<td>Product</td>
<td>SR</td>
<td>SUP</td>
</tr>
<tr>
<td>Price (PP +/− X)</td>
<td>($2.99)</td>
<td>($10.99)</td>
</tr>
<tr>
<td>Unit</td>
<td>TV6</td>
<td>TV2</td>
</tr>
<tr>
<td>Seller</td>
<td>DEMO</td>
<td>DEMO</td>
</tr>
<tr>
<td>Substitution for Virtual Unit? (Y/N)</td>
<td>N</td>
<td>N</td>
</tr>
<tr>
<td>HE1</td>
<td>3</td>
<td>12</td>
</tr>
<tr>
<td>HE2</td>
<td>3</td>
<td>12</td>
</tr>
<tr>
<td>HE3</td>
<td>3</td>
<td>12</td>
</tr>
<tr>
<td>HE4</td>
<td>3</td>
<td>12</td>
</tr>
<tr>
<td>HE5</td>
<td>3</td>
<td>12</td>
</tr>
<tr>
<td>HE6</td>
<td>3</td>
<td>12</td>
</tr>
<tr>
<td>HE7</td>
<td>3</td>
<td>12</td>
</tr>
<tr>
<td>HE8</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>HE9</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>HE10</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>HE11</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>HE12</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>HE13</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>HE14</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>HE15</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>HE16</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>HE17</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>HE18</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>HE19</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>HE20</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>HE21</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>HE22</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>HE23</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>HE24</td>
<td>3</td>
<td>12</td>
</tr>
</tbody>
</table>

- **Delivery date** – the date the product offered is to be delivered
- **Commodity** – active or standby (Type)
- **Product** – regulating, spinning or supplemental reserve
- **Offer Price** – price offered plus the pool price (Price)
- **Unit ID** – unit/load to provide reserve
- **Participant ID** – company selling the reserve (seller)
- **Provides an indication of whether this is the original offer or a substitution for a previous offer** (Substitution for virtual unit Y/N)

- **Volume offered in each hour**
- **The maximum operating reserve volume the unit is capable of providing** (Unit Max)
- **The maximum amount of the product available** (Product Max)
- **The minimum amount of the product available (0 or five MW)** (Product Min)
**Over-the-Counter Offer Guidelines**

1. Participants can provide offers for on peak hours, off peak hours, or both.
2. Participants must offer the same amount of volume for all hours (on peak, off peak or both) in their offer. Participants cannot pick and choose specific hours to offer volume, nor can they provide different volumes for different hours.
3. The minimum amount of volume a participant can provide is five MW. If a participant does not transact volume on Watt-Ex they must indicate that their minimum required volume for OTC is five MW.
4. If providing more than one offer on the same unit, the participant must indicate the maximum volume the unit can provide in OTC.
5. If providing more than one offer for the same product on the same unit, the participant must indicate the maximum volume for the product.

The AESO sorts the offers received by product from least cost to highest cost and allocates the volumes required starting with the least cost offer. This means that not all offers will necessarily be accepted if the volumes offered exceed the volumes of reserve required by the AESO.

Participants whose offers are accepted receive an email notification from the AESO listing the volumes and associated prices that were accepted. Participants also receive a fax confirmation from the AESO outlining the terms of acceptance. Participants must sign and return this fax to the AESO within two business days.

For more information on the OTC market please see the OTC training for market participants in the ancillary services section of the AESO website.

**Standby volumes in the Watt-Ex market**

All standby volumes are typically purchased through Watt-Ex and therefore the majority of OTC contracts are used to procure left over active volume. In the event that all the D-1 standby reserve is not purchased via Watt-Ex, then OTC contracts can be used. However this is a very infrequent occurrence.

Since the OTC market does not allow for transparency of individual prices or volumes to other market participants, the AESO publishes the Weekly Operating Reserve Price Report to the ETS section of our website under Current Reports. The report contains a rolling average of prices paid for all operating reserve transactions.
The Daily OTC Transaction report is also available to participants and provides users both the weighted average premium/discount of accepted offers, as well as the average volume procured for each product by on peak and off peak hours. Each morning at 7:30 a.m., the OTC transactions report updates with OTC data from the previous trading day. The OTC transactions report is available on the ETS section of the AESO website under Historical Reports.

Further information on OTC transactions is also available in the operating reserve section of the Weekly Market Report published on the ETS section of the AESO website under Historical Reports.

### Active Pricing Summary

<table>
<thead>
<tr>
<th>Watt-Ex</th>
<th>Over-the-counter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dispatch Payment</td>
<td>Pool Price + Equilibrium Price</td>
</tr>
<tr>
<td>Directive Payment</td>
<td>Pool Price for energy provided</td>
</tr>
<tr>
<td>Dispatch Payment</td>
<td>Pool-Price + Offer Price</td>
</tr>
<tr>
<td>Directive Payment</td>
<td>Pool price for energy provided</td>
</tr>
</tbody>
</table>
Pricing in the Standby Reserve Market – Watt-Ex

The AESO buys the majority of required standby reserve through the Watt-Ex platform, but uses a different pricing process than that used in the active reserve market. Standby reserve is compensated using a two-part option type payment with a premium or availability payment. An activation price is applied if the resource is dispatched by the system controller.

This market is referred to as a pick market since the buyer and sellers are able to complete a transaction at any time during the trading session by accepting any visible offer or bid on Watt-Ex.

**Premium Price** – the price paid to the seller to provide the AESO system controller the option to call on the reserve if required.

**Activation Price** – the price paid to the seller if the AESO system controller dispatches the reserve.

**Pool Price** – the price paid to the seller if the dispatched reserve is directed to provide energy. When directed to provide energy the seller will continue to receive the activation price and will also receive the pool price for energy provided.

<table>
<thead>
<tr>
<th>Watt-Ex/Over-the-counter</th>
<th>Availability payment</th>
<th>Dispatch payment</th>
<th>Directive payment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Premium price</td>
<td>Activation price</td>
<td>Pool price</td>
<td></td>
</tr>
</tbody>
</table>

**Activation of standby reserve**

Standby reserve is activated (dispatched) when the resources available under the active portfolio are insufficient to meet the operational and reliability requirements of the Alberta Interconnected Electric System.

The standby reserve merit order sorts all the standby volumes procured for each product from least cost to highest cost. The least cost volumes are activated first, however, the dispatch of one amount of standby volume does not mean that all standby volumes will be dispatched, since only the volume required to address the deficiency in active reserve will be dispatched.

As the supply and demand balance shifts throughout the day, the system controller uses the merit order to dispatch reserve to meet the necessary demand on the system.
Operating Reserve Settlement

EXCHANGE TRADED RESERVE (WATT-EX)
Watt-Ex serves as a clearing house for operating reserve procured by the AESO on the exchange. Sellers receive payment directly from Watt-Ex for reserve sold, and in turn, the AESO receives an invoice from Watt-Ex and financially settles with them.

OVER-THE-COUNTER CONTRACTS (OTC)
Based on the contract between the AESO and an operating reserve provider, an invoice is submitted by the provider to the AESO by the 10th business day of the month following the month in which the reserve is provided. The AESO reviews the invoice and validates it against the contract terms and the actual reserve provided. On the 15th business day of the month, the AESO issues a statement of account to each provider which includes details of payment for the previous month’s operating reserve. Financial settlement of the statement of account occurs on the 20th business day of the month.
Internal Controls for Procurement of Operating Reserve

The procurement of operating reserve is governed by formal AESO internal policies. Once a year, or whenever changes to any relevant policies occur, Commercial Services staff are required to sign an acknowledgement letter indicating they have read, understood, and are in compliance with the policies that govern Commercial Services practices.

On a daily basis, the AESO’s Settlement and Risk department monitors trading activity and notifies Commercial Services staff if irregularities occur. Both OTC and Watt-Ex transactions are scrutinized for compliance with the OTC and Watt-Ex commercial agreements and all internal risk management guidelines.
Transmission Must-Run (TMR)

Transmission must-run is generation required to be online and operating to ensure reliability in specific areas of Alberta where there is insufficient transmission capacity to support local demand and guarantee system reliability.

This service is typically procured through commercial contracts between the AESO and suppliers. TMR is intended to be a temporary measure, put in place to ensure system reliability until the transmission system is reinforced.

**CLASSES OF TRANSMISSION MUST-RUN SERVICE**

The AESO has defined two classes of TMR services: foreseeable and unforeseeable. TMR services are foreseeable if the AESO, taking into account reasonable procurement timing requirements, determines TMR services are required to meet AESO Transmission Reliability Criteria. This criteria includes consideration of expected operating conditions and planned transmission outages. The AESO contracts for foreseeable TMR services in advance of need.

TMR services are unforeseeable if they cannot be planned for in advance and are required in response to problems arising in real time (as opposed to in the planning horizon). The AESO compensates providers of unforeseeable TMR services under the terms and conditions of the Tariff.

**PROCUREMENT OF TRANSMISSION MUST-RUN SERVICE**

Given the location specific nature of TMR, only certain generators in Alberta are needed to provide this service. The AESO currently has contracts in place with generators to provide transmission must-run service in the Northwest Region of the province due to the lack of transmission capacity to service local demand in that area.

The AESO’s objective is to use a competitive procurement process, issuing requests for proposals (RFPs) when possible. TMR services are procured through bilateral agreements with generators when long term requirements for TMR are identified.
COMPENSATION METHODOLOGY FOR TRANSMISSION MUST-RUN SERVICE

TMR agreements compensate the service provider using fixed and variable payments. A fixed payment by the AESO to the TMR provider does not change with heat rate, gas price or usage, allowing the AESO to call upon the facility for TMR if required.

Variable payments are based on keeping a generator whole up to an established benchmark price based on the unit’s specific heat rate when dispatched for TMR and other operating cost components. In an hour when a TMR provider is dispatched to provide service, if the generator’s benchmark price is less than the pool price, no variable cost is incurred and no variable TMR payments are made. If the generator’s benchmark price is greater than the pool price, a variable cost is incurred and a variable TMR payment is made based on the differential between the benchmark price and the pool price. The majority of transmission must-run costs are variable costs.

Heat Rate: A measure of a generator’s thermal efficiency generally expressed in Btu per net kilowatt hour. It is computed by dividing the total Btu content of fuel burned for electricity generation by the resulting net kilowatt hour generation.

CONSCRIPTION OF TRANSMISSION MUST-RUN SERVICE

The AESO system controller is permitted by ISO Rules and the Tariff to conscript a generator that does not hold a TMR contract to provide TMR service if required. The generator is compensated in accordance with Article 11 of the AESO Tariff Terms and Conditions.

For full details on documents to submit to the AESO in order to receive compensation and other instructions refer to Compensation for Unforeseeable Transmission Must Run Services (“TMR”) in accordance with Article 11 of the AESO Tariff found on the AESO website.
OPP 501 Northwest Area Operation
The electric system in the northwest area of Alberta consists of long, heavily loaded 144 kV and 40 kV transmission lines with a low degree of redundancy of transmission paths. The area generating capacity is substantially less than the area load, which leads to inflows of energy into the area under normal circumstances and the outage of a single transmission line or a local generator can result in voltage depressions. This OPP defines the policies and procedures required to operate the northwest area of the Alberta Interconnected Electric System using transmission must-run generation and voltage management.

OPP 510 Calgary Area Operation
Calgary area load is supplied mainly by north generation in the Lake Wabamun area, imports from B.C. and generation in southern Alberta. To ensure system reliability, if the minimum required dynamic reactive reserve is not available from normal energy market dispatches, then TMR dispatches or directives will be issued to bring additional Calgary area generator(s) on line to provide the necessary dynamic reactive reserve. This OPP defines the policies and procedures for managing Calgary area dynamic reactive reserve including the dispatching of Calgary area transmission must-run (TMR) contracted generators and the directing of Calgary area generators that do not have TMR contracts.
Load Shed Schemes

In the same way that generation plays a role in maintaining reliable operation of the electricity grid, the demand side of the system (load) also makes a contribution to this important function. The AESO currently utilizes two types of load shed schemes: import load remedial action scheme and load shed service.

IMPORT LOAD REMEDIAL ACTION SCHEME (ILRAS)

ILRAS is a contractual agreement with interruptible loads that agree to be automatically tripped following an interruption to the B.C. intertie during high import levels.

LOAD SHED SERVICE (LSS)

Load shed service is currently procured by the AESO as a reliability tool designed to automatically curtail load when the system frequency drops below 59.5 Hz. This type of frequency problem could occur as a result of the loss of a large generator or transmission line that disrupts the balance of supply and demand on the system, or a trip of the B.C. intertie during high import levels.

Because the B.C. intertie is the single largest contingency on the Alberta system, at this time, the import limit on the intertie is constrained to protect the Alberta system from experiencing under-frequency problems should the intertie trip. Load Shed Service allows the available transfer capability (ATC) of imports over the B.C. intertie to be increased, protecting system reliability by acting as a fail-safe in the event of a trip on this important interconnection.

Currently, the AESO has agreements in place for approximately 150 MW of load shed service which allows for a maximum intertie import capability of approximately 600 MW over the B.C. intertie, depending on system conditions.

Automatic curtailment of load shed service is made possible by control systems that trip off load based on system frequency without any action required by the system controller. The system controller can also manually curtail load as described in OPP 801 Supply Shortfall.
TECHNICAL REQUIREMENTS FOR LOAD SHED SERVICE PROVIDERS
In providing load shed service, the participant agrees to make their interruptible load and automatic load available for curtailment at any time. Load shed service providers must meet specific technical requirements which are identified in the procurement process.

COMPENSATION FOR LOAD SHED SERVICE
A load shed service provider is paid an availability payment for making the load available to be curtailed. In the event they are curtailed, the provider is paid a separate curtailment payment.

Load Definitions
- **Automatic Load** is load that can be curtailed without any system controller action when frequency drops below the acceptable level of 59.5 Hz
- **Curtailment** is a reduction in consumption of load
- **Interruptible Load** is the load available to be curtailed in response to a curtailment directive
- **Curtailment Directive** is an ancillary service directive issued by the system controller to the service provider directing curtailment of interruptible load

OPP 301 Alberta – B.C. interconnection Scheduling
The Alberta – B.C. interconnection serves as an important transmission element in the Alberta Interconnected Electric System by providing a link to the western interconnection. This OPP defines the policies and procedures for the system controller to apply when scheduling interchange transactions on the Alberta – B.C. interconnection. Interchange scheduling is an important function in facilitating the transfer of energy to meet market supply and demand, while maintaining the operational reliability of both balancing authorities.

OPP 312 Import Load Remedial Action Scheme (ILRAS) and Load Shed Service (LSS)
This OPP defines the policies and procedures that guide the system controller in application of the import load remedial action scheme (ILRAS) and the load shed service (LSS), to facilitate increased import capability on the Alberta – B.C. intertie for energy and reserve services.
**OPP 404 Ancillary Service Dispatches and Directives**

This OPP defines policies for the system controller and participants, and procedures for the system controller, in the exchange of ancillary service dispatch and directive messages and responses. The system controller uses an Automated Dispatch and Messaging System (ADaMS) to send dispatches, directives, and system messages to participants. Voice communication is still required in some circumstances and serves as a back-up dispatch and messaging method.

**OPP 801 Supply Shortfall**

A supply shortfall is a condition where there is insufficient energy offered in the energy market to meet the requirements of load in Alberta. Different events such as generation and/or transmission contingencies, energy market deficiencies, or unexpected demand levels within the Alberta balancing authority can all contribute to a supply shortfall. Supply shortfalls could ultimately require curtailment of firm loads in order to maintain system reliability. This OPP outlines the remedial actions the system controller will take in a shortfall situation in order to preserve reliable operation of the Alberta Interconnected Electric System, including the dispatch of contingency reserve, before curtailing firm loads.

**Current technical limitations of load shed service**

Alberta’s two interties to neighboring jurisdictions, B.C. and Saskatchewan, are both subject to congestion that reduces their available transfer capability (ATC), the amount of energy that can be transferred into and out of the province. The B.C. intertie is rated at 1200 MW for imports and 1000 MW for exports, however, Alberta has never scheduled power flows to these levels due to the need to maintain reliability requirements.

**PROPOSED LOAD SHED SERVICE IMPORTS (LSSI)**

The long-term goal of the AESO is to restore the import capacity of the interties to their full potential. Procuring more load shed service in its current form has both reliability and energy market impacts and serves as an incomplete transmission substitute because it allows greater use of the B.C. intertie in only the import direction.

The AESO is currently consulting with industry to design a new type of load shed service that addresses the limitations of the current service by making it armable. The new load shed service import (LSSI) product could be turned on or off by the system controller and would not trip off load even if system frequency dips below the acceptable level. The flexibility built into this new service would address the problem of load shed service creating reliability threats under export conditions.
Technical requirements of proposed load shed service imports
To be effective, the technical standards necessary for load shed service imports will require response times of about 12 cycles (0.2 seconds), which limits the scope of potential providers to load participants. However, if other types of providers such as fast ramping generation or storage batteries can meet the technical standards for LSSi, potential suppliers of LSSi would not be restricted to loads.

Procurement of load shed service imports
The AESO anticipates procuring load shed service imports using bilateral contracts through a request for proposal (RFP) process. Depending on the level of participant interest in load shed service imports, the AESO may terminate the current load shed service product.

The need for load shed service imports will continue until the transmission infrastructure that supports the B.C. intertie is upgraded. As well, if additional interties are connected to the Alberta Interconnected Electric System, the requirements for load shed service will need to be re-evaluated at that time.

As Alberta’s electric system continues to expand to meet demand, the requirements for load shed service will change accordingly. Any load greater than five MW is eligible to provide load shed service if they can meet specific technical requirements. At present the AESO has procured all the load shed service required for Alberta.

The procurement process for load shed scheme services can be found in the Ancillary Services section of the AESO website.
Black Start Service

In the unlikely event of a system-wide blackout, the AESO requires the assistance of generators who have the ability to self-start with no outside generation source to help re-energize Alberta's electric system. The AESO currently has contracts in place with various generators across the province to provide black start service as part of our accountability to ensure reliable system operations. The AESO will continue to require this critically important service for the foreseeable future as a preparedness measure in the event of a system-wide blackout.

PROCUREMENT OF BLACK START SERVICE

The AESO identifies the need for black start service sufficiently in advance to allow time to conduct an Expression of Interest (EOI) for generators interested in providing this service. The Expression of Interest includes statutory pricing limits and outlines any applicable principles. If the EOI attracts sufficient interest and the AESO deems that the service contract is likely to be contested by interested providers, a Request for Proposal (RFP) will be undertaken to procure black start service competitively.

The procurement process for black start service can be found in the Ancillary Services section of the AESO website.

Who pays for black start service?

Similar to the process for recovering costs for other ancillary services, the cost for black start service is recovered from load customers in accordance with section 47(a)(i) of the Transmission Regulation.

Cost recovery for black start service is identified in the rate component of the AESO Tariff available on the AESO website.
TECHNICAL REQUIREMENTS FOR BLACK START SERVICE PROVIDERS

Any generator agreeing to provide black start service must demonstrate the ability to meet the technical requirements identified in the service contract. The black start resource must have the ability to self-start without any source of offsite electrical supply from a station which is initially in a fully de-energized state. If an onsite emergency generator is used during start-up, the black start resource must have sufficient fuel resources to provide reliable black start capability.

The AESO coordinates annual system restoration drills involving over 200 key industry participants to rigorously test the processes, resources and technical ability to safely recover the Alberta grid following a complete blackout. As part of the technical requirements for supplying black start service, providers of this service must participate in this exercise.

Service providers also have an accountability to train the operators of their resource facilities and test the start-up and operation of the resource on an annual basis. Where practical and feasible, this testing will extend to arranging with the interconnecting Transmission Facility Owner to test the energization of the line and pickup of load.

COMPENSATION FOR BLACK START SERVICE

Black start service providers are compensated based on the annual cost associated with ensuring their facilities are capable of providing the service. This includes costs related to maintaining black start equipment in a ready state as well as costs related to testing and staff training.

CONSCRIPTION OF BLACK START SERVICE

In order to provide black start service, a generator requires specialized equipment. Due to the cost associated with this type of equipment most generators choose not to build it into their facilities during construction. For these reasons, this service is normally not available for conscription and must be contracted in advance of need.

OPP 1101 Blackstart Restoration

In the event of a system-wide, catastrophic failure, it is imperative that approved procedures and processes are in place to enable restoration of the entire transmission system in a safe, reliable, coordinated and expedient manner. This OPP ensures all Transmission Facilities Owners of the Alberta Interconnected Electric System, and the AESO, have approved blackstart restoration procedures and processes in place.
List of Applicable Operating Policies and Procedures (OPPs)

A full list of OPPs can be found in the Rules & Standards section of the AESO website.

<table>
<thead>
<tr>
<th>OPP 301 Alberta – B.C. interconnection Scheduling</th>
</tr>
</thead>
<tbody>
<tr>
<td>The Alberta – B.C. interconnection is an important transmission element to the Alberta Interconnected Electric System in providing a link to the western interconnection. This OPP defines the policies and procedures for the system controller to carry out when scheduling interchange transactions on the Alberta – B.C. interconnection. Interchange scheduling is an important function in facilitating the transfer of energy to meet market supply and demand, while maintaining the operational reliability of both balancing authorities.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>OPP 312 Import Load Remedial Action Scheme (ILRAS) and Load Shed Service (LSS)</th>
</tr>
</thead>
<tbody>
<tr>
<td>This OPP defines the policies and procedures for the system controller in the application of the import load remedial action scheme (ILRAS) and the load shed service (LSS), in order to facilitate increased import capability on the Alberta – B.C. intertie for energy and reserve services.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>OPP 401 Regulating Reserve Service</th>
</tr>
</thead>
<tbody>
<tr>
<td>As a member of the Western Electricity Coordinating Council, the AESO is required to carry sufficient operating reserve. The criteria for determining minimum operating reserve, contingency reserve plus regulating reserve, are established by the WECC. The AESO has an obligation to procure regulating reserve from the ancillary service exchange or by other means. The system controller may be required to adjust the volume of regulating reserve in real-time based on actual system conditions.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>OPP 402 Supplemental and Spinning Reserve Services</th>
</tr>
</thead>
<tbody>
<tr>
<td>Defines the contingency reserve criteria for the Alberta Interconnected Electrical System and provides guidelines and procedures for the system controller to dispatch assets for supplemental and spinning reserve and to issue an ancillary service directive for the delivery of supplemental and spinning reserve energy.</td>
</tr>
</tbody>
</table>
OPP 403 External Spinning and Supplemental Reserves from B.C.
As a member of the Western Electricity Coordinating Council (WECC), the AESO is required to adhere to WECC’s Minimum Operating Reliability Criteria (MORC) which includes the requirement that balancing authorities maintain a minimum level of contingency reserve. To fulfill this requirement, the AESO must enter into an agreement with an ancillary service provider outside the Alberta balancing authority to provide the Alberta Interconnected Electric System with an external source for spinning reserve and/or external supplemental reserve.

OPP 404 Ancillary Service Dispatches and Directives
Defines the policies for the system controller and participants, and procedures for the system controller, in the exchange of ancillary service dispatch and directive messages and responses. The system controller uses an Automated and Dispatch and Messaging System (AdMaS) to send dispatches, directives, and system messages to participants. Voice communication is still required in some circumstances and serves as a back-up dispatch and messaging method.

OPP 405 Automated Northwest Power Pool Contingency Reserve Sharing
Defines the policies and procedures the System Controller must use to respond to or initiate a Northwest Power Pool Contingency Reserve obligation request either through the automated Pro-Rata Reserve Sharing system or via telephone when the system is unavailable.

OPP 406 Firm Load Responsibility
Outlines the process and calculations to be used by the AESO for determining firm load responsibility used in the contingency reserve calculations. As a participating member of Northwest Power Pool, the AESO is required to carry contingency reserve that is at least the sum of five percent of the Firm Load Responsibility served by hydro and wind generation, and seven percent of the Firm Load Responsibility served by thermal generation in the Alberta Interconnected Electric System. Firm Load Responsibility varies with system demand and a real-time calculation is required.

OPP 501 Northwest Area Operation
The electric system in the northwest area of Alberta consists of long, heavily loaded 144 kV and 40 kV transmission lines with a low degree of redundancy of transmission paths. The area generating capacity is substantially less than the area load, which leads to inflows of energy into the area under normal circumstances and the outage of a single transmission line or a local generator can result in voltage depressions. This OPP defines the policies and procedures required to operate the northwest area of the Alberta Interconnected Electric System using transmission must-run generation and voltage management.
OPP 510 Calgary Area Operation
The Calgary area load is supplied mainly by north generation in the Lake Wabamun area, imports from B.C. and generation in southern Alberta. To ensure system reliability, if the minimum required dynamic reactive reserve is not available from normal energy market dispatches, then transmission must-run (TMR) dispatches or directives will be issued to bring additional Calgary area generator(s) online to provide the necessary dynamic reactive reserve. This OPP defines the policies and procedures for managing Calgary area dynamic reactive reserve including the dispatching of Calgary area TMR contracted generators and the directing of Calgary area generators that do not have TMR contracts.

OPP 801 Supply Shortfall
A supply shortfall is a condition where there is insufficient energy offered in the energy market to meet the requirements of load in Alberta. Different events such as generation and/or transmission contingencies, energy market deficiencies, or unexpected demand levels within the Alberta balancing authority can all contribute to a supply shortfall. Supply shortfalls could ultimately require curtailment of firm loads in order to maintain system reliability. This OPP outlines the remedial actions the system controller will take in a shortfall situation in order to preserve reliable operation of the Alberta Interconnected Electric System, including the dispatch of contingency reserve, before curtailing firm loads.

OPP 1101 Blackstart Restoration
In the event of a system-wide, catastrophic failure, it is imperative that approved procedures and processes are in place to enable restoration of the entire transmission system in a safe, reliable, coordinated and expedient manner. This OPP ensures all Transmission Facilities Owners of the Alberta Interconnected Electric System, and the AESO, have approved blackstart restoration procedures and processes in place.

Rule 6 Dispatch and Directives
Defines the rules, terms and conditions by which the system controller will deliver dispatches and direct assets.
Glossary of Terms

Participants are encouraged to review the Authoritative Document Consolidated Glossary on the AESO website for up-to-date definitions of all terms in this manual.
Appendix I

Alberta’s Wholesale Electricity Market Design

The AESO develops and facilitates Alberta’s hourly competitive wholesale electricity market, which in 2010 had over 164 participants and traded approximately $5 billion in annual energy transactions. The AESO is focused on ensuring a fair, open and efficient market for the exchange of electric energy in Alberta and effective relationships with neighbouring jurisdictions and the greater balancing authority network. We ensure that Alberta’s competitive electricity markets continue to operate in the best way possible, demonstrating that reliability is not compromised and that the structure is sustainable, predictable and adds long-term value for Albertans. We develop market rules that assure a predictable market structure and provide a reliable price signal for producers, consumers and investors. This price signal is critical for private companies making investment decisions that will ensure an adequate supply of electricity for Albertans for many years to come.

ALBERTA MARKET CHARACTERISTICS

The Alberta wholesale electricity market is designed as a real-time, energy-only equilibrium market, or power pool. This means that suppliers are paid one single, hourly pool price for only the energy they deliver, not simply for building capacity. The single pool price model requires effective price signals for investment long term, for consumption response and for response from other markets. Additionally, this market model relies on an unconstrained transmission design to ensure that the pool price reflects the true price of delivered energy.

There are no transmission rights in Alberta. Instead, we have an injection-withdrawal system where transmission access is assigned in a non-discriminatory manner upon dispatch in the energy market. Transmission is paid for at a “postage stamp” rate, with no differentiation based on location – it doesn’t matter where the electricity is produced or used. At present, we have areas of significant transmission congestion, at times posing a challenge to the efficient dispatch of supply to meet demand.

Alberta is somewhat unique as an electricity market for a number of reasons. We are a relatively small market with limited interconnections. Due to the high level of industrial load, we have a very high load factor (80.3 per cent in 2010). On the supply side, we have diversity in existing and potential generation (coal, gas, wind, hydro, biomass) located across the province, though the supply mix is slowly shifting from predominantly base load coal to other fuels. We have a very healthy behind-the-fence generation industry, which means industrial sites produce some or all of their own electricity, then either buy their remaining requirements including backstop or sell their excess production in the market.
CONDITIONS FOR ENERGY-ONLY MARKETS

In a competitive market, generation investment decisions are made based solely on expectations of market performance. This basis for investment decisions means that Alberta’s electricity market framework must provide signals that are predictable and understandable, and it must support future investment in the electricity sector to provide a foundation for economic growth. Suppliers need confidence they can move their product to market and have the opportunity to compete, and customers need confidence that they will have a steady, reliable supply of electricity to enable their operations.

There are a number of conditions that are critical to the success of an energy-only market design, where the market price sends the only investment signal and thus price fidelity is key to market success. The market must be fair, efficient and openly competitive. It is important to have broad ownership and minimal barriers to entry. Price should be set by the balancing of supply and demand, so it is important to have limited transmission constraints. The ability of demand to respond to changes in the energy price is important as well, thus transparency of the price signal is a critical success factor.

When all of those conditions are met, a cycle of generation build develops. Periods of higher prices send a signal to investors that Alberta is a good place to build new generation. Inevitably, generation is built as a long term asset with economies of scale and the result may be a supply surplus condition leading to a period of lower prices reflecting the supply glut. During this period of lower prices, less efficient or older generation is shut down and additional new build may be cancelled or delayed. Over time, continued economic development creates growth in the demand for electricity, and prices once again start to rise. At that point, the cycle begins anew. This is precisely the cycle we have seen develop in Alberta in the 10 years since the deregulation of the generation market with more than 5,000 MW of new generation added (approximately $11 billion invested) since 1998.

Figure 1: Generation additions and retirements, 2001-2010
EVOlUtiON OF THE MARKET DESIGN

Alberta’s electricity industry continues to evolve, requiring the AESO to evolve the market design to ensure that we continue to deliver reliable power, reliable markets and reliable expertise. As Alberta’s electric system continues to evolve, the AESO must continue to adapt and contribute successfully to that change, ensuring the long term sustainability of the wholesale electricity market. Ongoing assessment has indicated that Alberta’s market is nimble and dynamic and therefore sustainable for long-term operation with these adjustments.

POLICY CONTEXT FOR MARKET EVOLUTION

As the AESO works to evolve the market design to stay ahead of the ever-changing environment, we take policy direction from the Department of Energy’s Electricity Policy Framework (ALBERTA’S ELECTRICITY POLICY FRAMEWORK: Competitive – Reliable – Sustainable, June 2005). The Framework outlines the following principles for the market framework (p.8):

1. The market framework must ensure that, over time, reliability is not compromised – the reliable delivery of electricity is the bedrock of Alberta’s economy.
2. The market framework must be guided and founded on fair and sustainable market and competitive forces.
3. The market framework must provide market signals to build new supply in a timely manner to meet growing demand while recognizing the lead-time required building new generation.
4. The market framework must provide confidence to investors and customers, and be supported by a clear and stable policy and regulatory framework.
5. The market framework must continue to preclude the exercise of market power and unwarranted transfer of wealth.
6. The market framework must accommodate the current state of restructuring and be flexible and adaptable to support the desired end state without any major government intervention.
7. The market framework and any required refinements must ensure the needs of all market participants, including the residential, farm and small business customers, are satisfied.
8. The market framework and any refinements or transition needed between the current and final states, must be fair, as orderly as possible, and provide certainty to existing and new market participants.
EVOLUTIONARY PRESSURES ON MARKET DESIGN

There are a number of existing pressures on Alberta’s existing electricity market design, and the AESO has undertaken programs to evolve the market structure, products, rules and systems and tools to meet these challenges head-on. They include the integration of renewable generation sources (particularly wind), areas of transmission constraints, interconnections to other jurisdictions with different market structures, demand response, supply surplus and the changing generation mix.

1. Renewables integration

Due to the variable nature of the resource (wind generation only produces electricity when the wind is blowing), there are certain challenges inherent with integrating significant quantities of wind generation in any electricity system. In essence, wind or other variable generation increases the challenge of balancing supply and demand in real time because the total amount of wind generation can change quickly and in an unpredictable fashion. These fast ramp rates up and down do not necessarily correlate with load patterns, and use of the generation merit order to over-dispatch to achieve a faster ramp rate results in price volatility. Forecasting wind accurately poses challenges, and when wind ramps up too fast the system may enter a situation where there are off-schedule flows on the interconnections with neighbouring jurisdictions and possible reliability standard violations. Additionally, significant amounts of wind coming on the system at $0 (wind is a price taker in the market) increases the possibility of supply surplus events in the short term, and may create impacts to long term adequacy and generation development as prices may be depressed.

Figure 2: Wind ramp event – July 20, 2009
Alberta has taken a leadership role in North America in finding ways to integrate more wind generation into the power system. Currently, Alberta has the third largest amount of installed wind power in Canada. A substantial amount of potential new wind power is also in various stages of development. There are 14 operational wind facilities in Alberta representing 777 MWs, approximately six per cent of the province’s total installed generation capacity. This is expected to increase to more than 1,300 MWs by the end of 2012, or approximately ten per cent of available generation capacity, and there are an additional 40 wind projects in the interconnection queue totalling nearly 5,000 megawatts.

Transmission plans reflect the need to interconnect new wind facilities. The South Area Transmission Reinforcement (or SATR) was included in the 2009 Plan to identify a long term solution to connecting increasing wind facilities in South Alberta. The AESO will continue to assess how market and policy changes impact future wind facilities and is committed to ensuring sufficient transmission to meet generation connection.

To further integrate wind on the grid, the AESO is working with industry on a phased implementation of the Market and Operational Framework for Wind Integration. This framework forms the foundation for initiatives to further refine rules, tools and operating practices without compromising system reliability or the fair, efficient and openly competitive operation of the market.

The AESO released a Short-Term Wind Integration Recommendation Paper in September 2010 that outlined the first phase of market changes required to integrate wind into the Alberta market. These phase one recommendations are intended to allow the safe operation of the system with about 1100 MW to 1500 MW of wind on the system and be implemented by the end of 2011. The relatively short timeframe required for implementation of the phase one recommendations dictated that they did not require significant changes to the market or new services to be in place.

This phase one plan has as its first step for the AESO to dispatch the Energy Market Merit Order (EMMO) to balance supply and demand, per normal operations, to balance energy needs. Contingency reserve is used when wind power ramps down more rapidly than can be handled by the EMMO. This is consistent with how sudden reductions in other generation are currently treated. Additionally, the AESO will rely on the use of Wind Power Management (WPM) to address wind power ramps that cannot be handled via EMMO. This involves limiting the additional increase in wind generation in successive 20-minute periods, essentially slowing the ramp to a staircase-like function to allow the rest of the market to keep up.

The final critical component to the integration of wind power, both in phase one and going forward, is the integration of site-specific wind power forecasting into system operations.
The ongoing phase two wind integration initiative allows a much broader approach and can include new tools and market products, as well as changes to existing ISO Rules.

Alberta’s real-time energy-only market framework provides significant flexibility in the approach for wind integration. At a high level, there are three types of approaches to resolving the supply uncertainty associated with variable generation such as wind. Each approach has different consequences to the market but is capable of resolving the operational challenges.

First, the uncertainty associated with wind generation can be equated to system events that are currently managed by the combination of energy market dispatches and ancillary services. Wind generation could be integrated on the system with changes to how generation is dispatched in the energy market, incremental volumes of ancillary services, and/or new ancillary services. The cost of wind variability is absorbed by other market participants in these options, and this cost is expressed through ancillary service prices and the energy market price.

Second, services can be developed that mitigate the uncertainty associated with wind, and these services would be paid for and/or supplied by wind generators. The services themselves may not be materially different than those that would be developed in the first group of options. The services would be centrally procured and operated by the AESO, but the costs would be charged back to wind generation operators. For example, a wind firming service would not place specific rule based obligations on wind, but it would provide the system with sufficient certainty around wind energy that the operational challenges would be resolved. In these options the cost of integrating wind is seen through a market service paid for by wind generators.
Third, rules can be developed for wind generation that eliminate or reduce the uncertainty to a level such that the remaining variability can be managed with existing reliability tools. Must offer must comply rules that apply to all non-wind generators in the market provide a degree of supply side certainty to the system controller. Must offer must comply rules that result in greater production certainty from wind units would resolve the operational challenges associated with variable generation. Wind variability is paid for by wind generators in these options, and the cost of integrating wind power will be unique to the solution adopted by each wind generator.

The AESO is committed to continuing to work with market participants through 2011 and into the future to fully examine all of these options as they relate to integrating the growing portfolio of renewables in Alberta.

2. Transmission constraints

A robust transmission system provides reliable service, attracts new generation, supports merchant or independent transmission projects, encourages investment and facilitates a competitive energy marketplace. It must provide non-discriminatory access and sufficient transmission capacity to ensure all supply and load customers can connect without constraints. It ensures generation is not stranded making it unavailable to the market and helps restore the original designed capacity of existing interties and prepare for connection of future interties to the system.

To provide system access, the AESO plans transmission expansions and enhancements so that 100 per cent of a generator’s in-merit energy can be dispatched under normal system conditions. That is, transmission development plans must accommodate all anticipated in-merit generation and must ensure reliable operation including acceptable system performance during credible contingency events as defined in established reliability criteria and standards. The AESO has an obligation to provide system access, but recognizes that congestion may occur from time to time. The AESO’s role is to ensure that there are adequate transmission facilities available so that the system can operate in a safe, reliable and efficient manner and to promote a fair, efficient and openly competitive market for electricity.

Rules are required to address interim transmission congestion that may occur on the system due to a lag in transmission development or in real time during contingencies. In real time, any constraints are managed by the system controller according to the recently approved Transmission Constraints Management (TCM) rule. Work is underway at the AESO to fully integrate this new rule with all systems and operating procedures.
When congestion is visible in the planning horizon, and cannot be handled through real time operator action, remedial action schemes (RAS) may be employed to facilitate market participation while maintaining system reliability and protecting system facilities. Market participants seeking to interconnect to the system may be assigned a RAS on a temporary basis prior to system reinforcements. RAS requirements may be identified in the planning stage of system development or when system studies are undertaken. RAS may also be used as a permanent non-wires solution to address issues that arise on a regional or system wide basis.

The AESO has been working with market participants to develop rules for these instances. The proposed Connection RAS Rules specify AESO and customer obligations in determining the need for and the use of a connection RAS to facilitate the connection of customers to the system in advance of the completion of the construction of all necessary system facilities. Work continues with stakeholders to finalize and implement these refined rules.

3. Interties – connecting beyond Alberta

Interties are transmission lines that connect Alberta to our neighbours and allow us to import and export power. Interconnections with neighboring jurisdictions are essential to a well functioning (FEOC) market. They support reliability and help achieve the most efficient, economic and environmentally beneficial exchange for Alberta's resources. Connections to competitive markets also create investment and trade (import/export) opportunities and continued economic growth, and encourage new generation development (particularly for baseload generation that has a must-run level and for wind). With only two interties – one with British Columbia (B.C.) and the other with Saskatchewan – the Alberta Interconnected Electric System (AIIES) is one of the least interconnected jurisdictions in Canada. In addition, the B.C. intertie is operating below its rated capacity due to congestion on the intra-Alberta transmission system.

Alberta has been a net importer of electricity since 2002. Historically, there have been some synergies between B.C. (predominantly hydro) and Alberta (predominantly coal-fired), leading to flows from B.C. into Alberta during peak hours and from Alberta to B.C. during off-peak.
While there are recognized benefits, there are a number of hurdles or challenges to overcome when we talk about trading electricity across jurisdictions. Seams – different regulatory, tariff and market structures – can create barriers to trade and potentially unlevel playing fields. Different market designs exist throughout WECC, including power pools, regulated monopolies, Independent System Operators (ISOs) and bilateral markets. Each market has different characteristics including market structure (day ahead, hourly, real time, pricing mechanisms, capacity vs. energy-only), timelines for trading, products, regulatory structures for generators (merchant vs. regulated rate base), tariffs, regulatory bodies and market rules. These differences create seams and affect the ability of participants in each area to trade on a level playing field with one another.
The changing nature of generation, including the increased presence of renewables, also has an impact on trading electricity across the interties. Electricity markets were designed around the operating characteristics of traditional generation (fossil, hydro and nuclear). Renewable Portfolio Standards (RPS), Feed in Tariffs (FIT) and other legislation in Alberta or in the extended trading area encourage the replacement of traditional sources with renewable sources. These are often intermittent (wind, solar) and can impact market design specifically as it relates to interties, with a requirement to move to scheduling closer to real time vs. traditional hourly firm transmission schedules.

The AESO continues to work with companies that are proposing merchant transmission lines to connect Alberta to external jurisdictions. Our responsibility is to make sure these projects are safely and reliably connected with Alberta’s transmission system, and to identify any direct benefits that could be delivered to the province. The first such project, Montana Alberta Tie Line (MATL), is being built by a Calgary-based energy transmission company. It is a 230 kV, 345 km transmission line between Lethbridge and Great Falls, Montana. When completed later in 2011, it will be the first direct intertie between Alberta and the United States, will enable development of new energy projects in both regions, and provide a new source for electricity to Alberta. The project developer is responsible for construction costs and will look to recover costs from those using the line to transport power into and out of Alberta.
A review of the intertie framework is required to ensure it supports fair, efficient, and openly competitive (FEOC) intertie transactions while advancing government policy. In preparation for the energization of MATL and in future consideration of expanded interties, the AESO needs to work through the seams in operation and market design, scheduling timeframes and rights to transmission and tariff products between Alberta’s energy market and other jurisdictions. As such, the AESO is both putting in place the rules, operating procedures and system configuration to integrate the MATL line in 2011, as well as developing a market framework for all interties. This will facilitate the development of new intertie capacity and the operation of existing and new interties.

In late 2010, the AESO published a series of recommendations pertaining to the intertie framework. From an energy perspective, the recommendation is for dynamic scheduling to be implemented to enable the capability for imports/exports to submit priced bids/offers. This starts to make imports and exports participate more like internal generators and loads in the market. From a transmission perspective, the AESO is recommending that the AESO plan the transmission system so that each intertie can transfer to its path rating simultaneously. This will minimize the curtailment of scheduled flows across the interties due to limitations on transfer capability from Alberta system constraints. The AESO also recommends a merchant transmission service (MTS) will be offered that reflects system access service to injection/withdrawal at the border for merchant developers. Finally, as a means to allocate ATC when there is congestion or until transmission reinforcements can be made, the AESO recommends an ATC allocation rule be implemented that arbitrates first by energy price, and then by pro-rata.

The AESO continues to consult with market participants on the implementation of the recommended framework.
4. Demand side participation

As electricity markets evolve across North America, there is a concerted effort to get the demand side of the market, i.e., consumers, to be more active rather than passive participants in the market. This is often referred to as demand response, and can lead to a more robust market, with more efficient outcomes. There are two types of demand response: price-responsive demand response and controllable demand response.

In the first instance, consumers have visibility of dynamic prices, and respond to periods of high prices by reducing consumption. The benefit is a reduction in overall electricity costs by avoiding consumption during high-priced periods. In Alberta, energy market participation is possible either by (1) formally bidding demand or load curtailment into the AESO energy market or (2) simply responding to observed prices. Currently, no load participates directly in the AESO energy market by bidding in price-responsive demand bids. There is evidence of price response based on observed energy market prices (i.e., without bidding demand into the AESO market). These customers voluntarily reduce loads when prices increase, and add up to 200-300 MW of reductions. Research has shown that wholesale customers can reduce their overall electric energy charges by 20 to 30 per cent by avoiding consumption during the highest priced hours.

The second type of demand response involves a customer agreeing to be curtailed under certain conditions, either via direct control or by a dispatch instruction from the system operator. In return, they receive payment for providing the service. The AESO presently has a number of these programs, designed to support reliability. They include Load Shed Service (LSS), Import Load Remedial Action Scheme (ILRAS), Load Shed Service for Imports (LSSI) – this product is new and will replace both LSS and ILRAS, Voluntary Load Curtailment Program (VLCP) and Under-Frequency Load Shedding Scheme (UFLS).

Demand response providers can also participate in the operating reserve market in direct competition with generators. Currently, this is restricted to the Supplemental Reserve market but the AESO plans to take steps to allow more types of reserve providers to compete.

The AESO is working with market participants to design a path forward on implementing further demand response initiatives in Alberta.
5. Supply surplus

There is a significant amount of generation that offers into the electricity market at $0, effectively positioning themselves as price takers. These include the minimum stable generation level of baseload producers such as coal-fired plants, the must-run portion of cogeneration production that is required to produce enough steam to support their industrial processes, all wind generation due to its variable nature, some hydro due to environmental factors and all imports. On average, there are between 5,000 and 6,000 MWs that are at $0 in the supply stack. When demand for electricity is low, it is possible that demand falls to within the level of these $0 offers, and the AESO must determine which generation to dispatch off in order to balance supply and demand. This is termed a supply surplus condition.

Going forward, as the generation mix changes, there is going to be the increasing possibility and frequency of supply surplus conditions when there is substantial wind generation, particularly during a low load hour. There may also be supply surplus concerns with significant cogeneration expansion, the addition of a large baseload unit such as nuclear or large hydro or in current high water spring runoff periods.

The AESO is working with market participants on a number of efforts to examine rules for supply surplus dispatches. This includes updating the supply surplus rule to address exemptions, the dynamic scheduling of imports so they no longer must offer at $0, and exploring ways in which wind might be able to offer (at something other than $0).

6. Generation mix post-2020

By 2020, the AESO expects total installed generation capacity to grow to 19,000 MW. Generation additions are not centrally planned in Alberta, nor do we have a fuel use policy. The current supply stack is weighted toward thermal/coal-fired generation. The future generation mix will largely depend on market and/or policy evolution. Natural gas may become more predominant as coal plants fuel switch and retool as they retire at 45 years of age or at the end of the Power Purchase Arrangements per proposed federal legislation. Gas-fired generation is anticipated to supply the short term growth gap, and cogeneration could continue to grow, largely as a function of oilsands growth. New technology, including clean coal, may become economically viable. Nuclear generation may be commercially viable on a small scale if it can be sized to fit industrial projects. Dispatchable battery storage technology could become large scale. The continued growth of wind is somewhat dependent on carbon policy. Large scale hydro development may become a reality. With all this uncertainty, it is clear that transmission infrastructure will need to facilitate development of an efficient generation mix, and the market will need to continue to evolve to support this changing generation mix.
CONCLUSION

The current electricity wholesale market design in Alberta has worked very effectively to-date. Private investment in generation has kept pace with load growth to ensure an adequate supply of electricity supporting the province’s economic growth without direct government intervention or taxpayer funding. That being said, pressures on market design require ongoing evolution. North American ISOs are all facing similar market challenges, indicating that market evolution is both natural and necessary. The AESO is committed to continuing to work collaboratively with market participants to identify evolutionary drivers, evaluate options and implement market changes. The continued success of our wholesale electricity market will ensure an adequate electricity supply to fuel the long term economic growth that benefits all Albertans.
Appendix J
2011 Long-term Telecommunications Plan

TABLE OF CONTENTS

1.0 EXECUTIVE SUMMARY 416
2.0 BACKGROUND 419
   2.1 Utility telecommunications system 419
   2.2 Role of the Alberta Electric System Operator (AESO) 420
   2.3 Objectives 421
      2.3.1 Objectives of the transmission plan 421
      2.3.2 Objectives of the telecommunications plan 421
3.0 AESO PLANNING PROCESS 422
   3.1 Stakeholder involvement 423
   3.2 Legislation and regulation 424
   3.3 Alberta’s Provincial Energy Strategy 424
4.0 2011 LONG-TERM TELECOMMUNICATIONS PLAN 425
   4.1 Overview 425
      Table 1: Utility communications applications and relevant standards 426
   4.2 Technology planning 427
   4.3 Telecommunications plan deliverables 428
   4.4 Opportunities for collaborative planning 429
      4.4.1 Technical and business drivers 430
   4.5 Utility network development projects 431
      Table 2: Major network development project table 431
   4.6 Major Development projects 432
      4.6.1 Edmonton region 432
      4.6.2 Red Deer area 432
      4.6.3 Calgary area 433
      4.6.4 Camrose area 433
      4.6.5 Southern Alberta Transmission Reinforcement (SATR) 433
      4.6.6 Potential communications network projects 433
5.0 Conclusion 434
6.0 Glossary 435
1.0 Executive Summary

Alberta’s electric transmission system relies on a province wide, utility-owned and operated communications network for its reliable, efficient, and safe operation. Section 10 of Alberta Transmission Regulation 86/2007 requires that the AESO prepare a Long Term Plan for the transmission system. When viewed by the definitions of the Electric Utilities Act (EUA), this infers that telecommunications system planning is to be included as part of that process.

The Long-term Transmission Plan (filed June 2012) – also referred to as the LTP or the Plan – which sets out the aforementioned plan for development of the transmission system to meet evolving electrical needs of the province, anticipates and includes a requirement for capital expenditures for associated utility telecommunications network growth and development. This 2011 Long-term Telecommunications Plan (the Telecommunications Plan) defines how that Utility Telecommunications network¹ will evolve and grow to support changes as described in the LTP.

The Alberta Interconnected Electric System (AIES) utility telecommunications networks are owned and operated by the Transmission Facility Owners (TFOs) and used for the transmission of teleprotection signals, operational data, SCADA data and voice and communications. Development and deployment costs are significant for new network segments or additions to existing networks. As such, a long time frame for planning is preferred to ensure that investments in network assets can support forecast growth in demands on the network. The Telecommunications Plan will be based on the same twenty year planning period as this Plan.

¹ Telecommunications system/network and communications system/network means the utility communications network within this document.
The following factors have been considered in the development of the Telecommunications Plan:

- Network development and capacity planning follows transmission system development that relies on, among other things, forecasts of load growth and future generation additions. The Alberta Electric System Operator (AESO) recognizes that many factors affect load and generation growth, and that the actual load in the future could be higher or lower than forecast which may impact the actual requirements for the telecommunications networks.

- The Microwave vs. OPGW Comparison paper – a technology evaluation and comparison performed by the AESO in conjunction with the TFOs – has identified that Optical Ground Wire (OPGW) is the preferred technology over microwave for deployment in utility telecommunication core networks. Although pricing out at an estimated 14 per cent higher cost, OPGW provides 300 times more capacity, reduces both licensing fees and land costs as well as providing enhanced overall reliability. As such OPGW is clearly better able to support long-term growth of the transmission system and the expanding number of applications (as described in Table 1) that operate over the telecommunications network.

- A long time horizon is required for planning purposes to ensure the telecommunications networks put in place today will be able to handle growth in network traffic arising from such applications as Phasor Measurement Unit (PMU) streaming, possible smart grid implementation and other potential applications not in wide scale use at this time.

- Adoption and deployment of smart grid applications and services will compliment the development of a robust, competitive market for electricity. While the extent and timing of such deployment is uncertain, the Telecommunications Plan takes into account the potential for the widespread deployment of applications such as Advanced Metering Infrastructure (AMI), Demand Response (DR), Distribution Automation (DA), and others related to the smart grid concept.

Over time, as the transmission system is upgraded as identified in the AESO’s 2011 Long-term Transmission System Plan, the Alberta Utility Telecommunications network will be established as identified by the map shown below. However, despite the fiber optics advantages, it is envisioned that the existing microwave systems will continue to be utilized; maintained and expanded where economics and practicality dictate that the microwave technology is the most appropriate solution.
Figure 1: Alberta fiber optic lines

- **Northwest Area Upgrade**
- **West Fort McMurray 500 kV**
- **East Fort McMurray 500 kV**
- **Cold Lake**
- **Athabasca Area**
- **HATRWest HVDC**
- **MATL**
- **Grande Prairie**
- **Edmonton**
- **Red Deer**
- **Calgary**
- **Medicine Hat**
- **Lethbridge**

**Fiber optic lines**
- Green: Existing fiber optic lines
- Orange: Estimated to be in service by 2012
- Blue: Estimated to be in service by 2014
- Red: Estimated to be in service by 2016
- Brown: Estimated to be in service by 2017
- Red: Estimated to be in service by 2020+
2.0 Background

2.1 UTILITY TELECOMMUNICATIONS SYSTEM

The Alberta transmission system is primarily owned and operated by four major Transmission Facility Owners (TFOs); AltaLink, ATCO Electric, ENMAX and EPCOR. Each TFO has a utility telecommunications system that provides equipment protection, supervisory control and data acquisition (SCADA), operational voice communications, and network access. In addition utilities operate extensive mobile radio systems with coverage over most of the province. These radio systems provide voice communications for field staff for both day to day operations as well as emergency power restoration.

The AESO's 2011 Long-term Transmission Plan (the Plan) identifies a substantial number of system projects that are required to be undertaken by the TFOs. These projects include the four major projects designated as Critical Transmission Infrastructure (CTI) projects as well as area transmission reinforcement plans such as the Southern Alberta Transmission Reinforcement (SATR), Hanna Region Transmission Development and the Southwest Transmission Plan. Telecommunication requirements typically account for three per cent to five per cent of the cost of transmission infrastructure expansions.

The intent of this paper is to describe a Long-term Telecommunications Plan that aligns with the Plan and identifies opportunities for efficiencies regarding new and existing projects undertaken by all TFOs. These efficiencies would include maximizing functionality and utilization of both new and existing telecommunications systems over the planning period, as well as incorporation of new and emerging technology to enhance the reliable and efficient operations of the power system. This, in turn, would provide benefits to customers, market participants, Independent Power Producers (IPPs), wire owners and all interconnected parties.

The deployment of new technology related to fibre optics presents a unique opportunity to install a system wide, primarily OPGW-based communications backbone for the utility telecommunications systems in conjunction with the transmission line build program. Due to the enhanced capabilities of fibre optics over microwave solutions, TFOs have indicated a preference to implement a hybrid fibre optics and microwave system. Fibre optics would be utilized wherever practical to provide high capacity communications capability.
2.2 ROLE OF THE ALBERTA ELECTRIC SYSTEM OPERATOR (AESO)

As explained in the Plan, the AESO is mandated to plan the transmission system based on legislation taking into account technical considerations, reliability standards and operating and planning criteria which ensure reliability and well functioning markets. Additionally, while developing the transmission system, the Provincial Energy Strategy, which details the Alberta government’s integrated vision for the continuing development of the province’s energy resources, must be taken into consideration. Primary responsibilities of the AESO as they pertain to telecommunications systems and requirements include meeting obligations as described under the Electric Utilities Act, which defines a transmission facility and transmission system to include telecommunications as follows:

1(1) (bbb) “transmission facility” means an arrangement of conductors and transformation equipment that transmits electricity from the high voltage terminal of the generation transformer to the low voltage terminal of the step down transformer operating phase to phase at a nominal high voltage level of more than 25,000 volts to a nominal low voltage level of 25,000 volts or less, and includes:

(i) transmission lines energized in excess of 25,000 volts,
(ii) insulating and supporting structures,
(iii) substations, transformers and switchgear,
(iv) operational, telecommunication and control devices (emphasis added)
(v) all property of any kind used for the purpose of, or in connection with, the operation of the transmission facility, including all equipment in a substation used to transmit electric energy from...

1(1) (ccc) “transmission system” means all transmission facilities that are part of the interconnected electric system.

And therefore the AESO is responsible for:

- Identifying transmission system enhancements that are required in the province, and thereby;
- Determining future telecommunications system and network requirements that may result from transmission development plans over the long-term;
- Ensuring that stakeholder feedback is solicited and considered throughout the process, and;
- Ensuring continued and reliable operation of the AIES, and therefore also of its supporting communications technologies.
2.3 OBJECTIVES

2.3.1 Objectives of the transmission plan

It is important to consider overarching objectives of the 2011 Long-term Transmission Plan when identifying objectives of the associated Telecommunications Plan, as the two are inherently linked. Among other goals, the transmission plan;

- Projects future electrical needs of the province relative to the current capability of the transmission system to determine where and when upgrades and expansions to infrastructure will be needed.
- Identifies the technical solutions or options that will best accomplish these expansions in the long term.
- Presents the AESO’s assessments and identifies projects that are necessary to ensure the transmission system is reinforced in support of Alberta’s economic growth.
- Evaluates both the bulk and regional transmission systems to develop a comprehensive strategy for enhancing the Alberta Interconnected Electric System (AIES).
- Encompasses a long-term view with a focus on projects that are forecasted to be required over the planning period.

2.3.2 Objectives of the telecommunications plan

Accordingly, specific objectives of the Telecommunications Plan include:

- Identifying where and when communications network associated projects are required to ensure that related operations requirements can be met for upgrades and expansions to the transmission infrastructure. An overview of major projects is provided in Table 1.
- Maximizing the value of collaborative planning, avoiding duplicate or inefficient investments not only in utility communications networks themselves, but also pertaining to TFO human resource requirements necessary to sustain planning, development and operation of the wide-area telecom network as the transmission plan is implemented.
- Identifying technically feasible and cost-effective solutions for communications system enhancements.
- Ensuring the communications system will be able to incorporate and accommodate new technologies that support the operation of the electrical system.

By continuing to work together to define objectives relating to utility communications needs, the AESO and the TFOs can enhance system reliability to ensure future development is implemented in the public interest.
3.0 AESO Planning Process

As with the Plan, an AESO long-term plan for telecommunications networks requires input from many sources, including TFO consultation, government legislation and regulations and other technical requirements. Additionally, communication network reliability is defined by compliance with planning and operating criteria consistent with North American standards, including existing as well as forthcoming Alberta Reliability Standards (ARS), North American Electric Reliability Corporation NERC standards, Western Electricity Coordinating Council (WECC) requirements etc. As they relate to communications, these standards are intended to ensure long-term system integrity as well as reliability.

Future requirements for utility telecommunications system planning are being determined through the following processes:

- Identification of current and future communications needs within each of the specific regions of the province, and of the communications network as a whole.
- The creation of a long-term utility telecommunications system development plan for the province.
- Involving TFOs and other stakeholders in the development and review process of the Telecommunications Plan.
- The AESO will then support, implement, and update the plan as appropriate.

Again, as with transmission system planning, consideration must be given to the fact that transmission infrastructure is generally built in large increments and development and implementation plans for any communications projects must be generated accordingly.

Also similar to the transmission plan, forecasting communications network capacity in conjunction with transmission system requirements well into the future mitigates the need to repeatedly upgrade utility communications systems as Alberta’s transmission system grows. As outlined in the microwave vs. OPGW paper aligning with transmission system expansion and growth affords the opportunity to maximize the use of rights-of-way and minimize impact on land and the environment.
3.1 STAKEHOLDER INVOLVEMENT

The planning and ongoing development of the AIES requires significant communication and collaboration between the AESO and the TFOs and Distribution Facility Owners (DFOs). Since a robust and effective Utility Telecommunications system is required to operate the AIES the planning for that communications network will require communication and collaboration between the stakeholders to ensure the outcomes will meet the needs of the AESO, the operators and regulators, as well as the end user.

Specific stakeholder involvement activities that support the planning process are:

- The creation of a Telecommunications Work Group in early 2010, led by the AESO with participation from the each TFO.
  - In May of 2010, the working group issued a discussion paper to identify potential gaps in the utility telecommunications system compared to the objectives of the 2009 Long-term Transmission System Plan.
  - In March of 2011 the working group issued a technology evaluation paper to assess the relative merits of the deployment of fibre optic cable (OPGW) compared to microwave for the communications network.
  - The working group is developing the 2011 Long-term Telecommunications Plan to align directly with the 2011 Long-term Transmission Plan.

- Starting in May 2011, a new Communication Standards Work Group will be established. The group will be led by the AESO and will have representatives from each TFO.
  - The mandate of the working group will be to review all existing applicable standards that relate to telecommunications so that they can be simplified and aggregated into a more comprehensive and manageable standard to guide utility telecommunications system developments.
    - The AESO will follow the authoritative documents process, including stakeholder consultation, in the development of an ISO communications rule for AUC approval.
    - Consultation with stakeholders regarding specific telecommunications upgrades will be included in transmission regional and area plans.
3.2 LEGISLATION AND REGULATION

The Electric Utilities Act (EUA) created the AESO and defines the organization’s roles and responsibilities for planning the Alberta Interconnected Electric System (AIES). The Transmission Regulation provides direction with regard to additional planning and operational duties. It directs the AESO to prepare and maintain a Transmission System Plan that identifies, among other things, the transmission facilities needed to meet the province’s needs.

Since the operation of the transmission system requires a functional and effective telecommunications network, the AESO must ensure the Transmission System Plan has an associated telecommunications plan capable of supporting it. The design and performance of the communications system will have a significant impact on the ability to meet Alberta Reliability Standards, adding to the importance of the communications plan.

3.3 ALBERTA’S PROVINCIAL ENERGY STRATEGY

The Provincial Energy Strategy provides high-level objectives and directions for how the province should work towards the sustainable development of Alberta’s energy resources and create an environment capable of supporting long-term economic growth. There are several specific outcomes, steps, objectives, and values that are relevant to the long-term telecommunications plan:

- Wise energy use is noted as a major outcome of the strategy. Having a strong communications network in place that can support the new applications for more efficient distribution of electricity and the monitoring of the efficient use of electricity will help to achieve that outcome.

- The Telecommunications Plan will directly support upgrades to the transmission system, and interties to other markets by ensuring their proper and effective operation.

- Finally the Telecommunications Plan, and the communications network deployments it will help to define, will provide value for Albertans by ensuring reliable service of the AIES, as well as increased access to other markets. This will be achieved through continued provision of efficient and effective communications and by enabling monitoring and reporting for any interconnection with energy systems in other regions.
4.0 2011 Long-term Telecommunications Plan

4.1 OVERVIEW

The Long-term Telecommunications Plan is required to ensure that the deliverables identified in the 2011 Long-term Transmission Plan can be met. The utility telecommunications system will play an increasingly important role in supporting an efficient, reliable and flexible transmission system moving forward.

The AESO established the Telecommunications Work Group that produced the Communications Plan for Alberta – Discussion Paper on May 31, 2010. The discussion paper identified gaps in the utility communications network backbone. Those gaps will be evaluated and addressed through this plan, and through ongoing long-term planning as the transmission grid evolves.

The AESO has worked to ensure that all requirements of the telecommunications systems have been identified and addressed. The technologies identified for use on the utility communications network have been chosen for their ability to support the list of applications below for both the near term and long term.
### Table 1: Utility communications applications and relevant standards

<table>
<thead>
<tr>
<th>Application</th>
<th>Current standard</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Teleprotection</td>
<td>Alberta Interconnected System protection standard</td>
<td>Currently under review and transition to ISO Rule</td>
</tr>
<tr>
<td></td>
<td>PRC-001-AB-1 Protection System Coordination</td>
<td>These and several other Protection related Reliability Standards are currently in effect</td>
</tr>
<tr>
<td></td>
<td>PRC-004 Generation Protection Misoperation</td>
<td></td>
</tr>
<tr>
<td></td>
<td>PRC-009-WECC-AB-1 Protection System and RAS Misoperation</td>
<td></td>
</tr>
<tr>
<td>SCADA</td>
<td>AESO SCADA Standard</td>
<td>Currently under review and transition to ISO Rule</td>
</tr>
<tr>
<td>Voice communication</td>
<td>502.4 Automated dispatch and messaging system and voice system communications requirements</td>
<td>Stakeholder Consultation complete and submitted to AUC for approval as ARS</td>
</tr>
<tr>
<td></td>
<td>ARS COM-001-AB Communications and Coordination</td>
<td>Both ARS COM Standards are currently under review and transition to ISO Rule</td>
</tr>
<tr>
<td>Substation management and monitoring</td>
<td>TOP-006 Monitoring System Conditions</td>
<td>Requirement to ensure critical reliability parameters are monitored in real-time</td>
</tr>
<tr>
<td></td>
<td></td>
<td>This standard has yet to be reviewed by AESO (NERC project 2007-3)</td>
</tr>
<tr>
<td>Data communications</td>
<td>TOP-005-AB-1 Operational Reliability Information</td>
<td>In effect</td>
</tr>
<tr>
<td>Corporate (internal telecom and IT)</td>
<td>EOP-008-AB-0 Loss of Control Center Functionality</td>
<td>Currently under review and transition to ISO Rule</td>
</tr>
<tr>
<td>Network security</td>
<td>CIP-001-AB-2 – CIP-009-AB-2</td>
<td>Pending development and implementation within Alberta</td>
</tr>
<tr>
<td>Disturbance monitoring and data reporting</td>
<td>PRC-018-AB-1 Disturbance Monitoring Equipment</td>
<td>Under review and transition to ARS. Numerous new PMU’s are to be added to the system; PMU data streaming for use in real-time is possible</td>
</tr>
<tr>
<td>Interoperations data</td>
<td>OPP 805 Loss of Vital Telecommunications Systems</td>
<td>Requirements for redundant telecommunications</td>
</tr>
<tr>
<td></td>
<td>TOP-005-AB-1 Operational Reliability Information</td>
<td>In effect</td>
</tr>
<tr>
<td></td>
<td>BAL-001-AB-0a Resource and Demand Balancing</td>
<td>In effect – requirements for Automatic Generation Control</td>
</tr>
<tr>
<td>Smart grid applications</td>
<td>There are no current Alberta standards for Smart Grid applications such as: Demand Response, Distributed Generation, Advanced Metering Infrastructure or Energy Storage</td>
<td>Pending AUC report to the Department of Energy</td>
</tr>
<tr>
<td>Weather/ environmental monitoring</td>
<td>TOP-006 Monitoring System Conditions</td>
<td>This standard has yet to be reviewed by AESO (NERC project 2007-3)</td>
</tr>
<tr>
<td>Metering data</td>
<td>AESO measurement system standard</td>
<td>Currently under review and transition to ISO rule</td>
</tr>
</tbody>
</table>

The services as described above are not an exhaustive list. There are many services and applications that use the network. This list does, however, highlight the growing list of services that rely on the underlying infrastructure and illustrates why a comprehensive network plan is required. Deployment of a telecommunication network capable of delivering the services identified is a complex task and involves not only detailed planning and development, but also operation and management of the network once built.
4.2 TECHNOLOGY PLANNING

The AESO and the Telecommunications Work Group have identified areas where there are gaps or shortfalls in the existing or planned communications network. In addition they have prepared a detailed comparison of microwave and OPGW for use in the core of the utility network to ensure that as new communications networks are planned or existing gaps are filled, the most efficient and cost effective technology is being deployed to better support the LTP.

The technology evaluation and selection process has been driven by the following key factors:

- The utility communications network must be able to operate with extremely high reliability to support the reliability objectives for the transmission system itself.
- The capacity requirements for the communications network continue to grow with the pace of growth expected to increase significantly as Smart Grid applications are added to portions of the network.
- Any selected network technology must meet the stringent requirements for low latency (for teleprotection) and be able to support the high standards for network security.
- The chosen technology must be economically viable as it relates to total cost of ownership over the planning period.
- The chosen technology will consider the goal to minimize the environmental impact of new transmission and telecommunications deployments.

With the aforementioned factors all having been taken into consideration, well planned and comprehensive potential solutions have been and continue to be developed. The technology evaluation and planning process helps to ensure the utility telecommunications network will be not only be cost efficient, but robust, reliable, and able to best meet transmission system requirements.
4.3 TELECOMMUNICATIONS PLAN DELIVERABLES

The AESO and the Telecommunications Work Group have assessed the evolving operational and communication needs of the utility communications network, and have evaluated the alternative technologies capable of supporting those needs.

This plan will help to guide utility communications system deployments relating to transmission system projects as follows:

- The creation of a utility communications network deployment plan that aligns with and supports the LTP.
- Existing technology standards can be simplified and aggregated to streamline the design and implementation of utility networks in Alberta. Existing relevant standards and plans include:
  - Alberta Interconnected System Protection Standard,
  - AESO SCADA Standard,
  - ISO Rule 502.4 Automated Dispatch and Messaging System and Voice Communications System Requirements,
  - Alberta Reliability Standard (ARS) COM-001,
  - Alberta Reliability Standard (ARS) COM-002,
  - AESO Measurement System Standard (metering),
  - System Restoration Plan.
- The identification of areas where collaborative planning between TFOs can increase the efficiency and effectiveness of the utility communications network and the transmission system. This will include opportunities to share bandwidth or fibre assets on existing or planned network segments among TFOs and the AESO, ultimately reducing operating costs incurred by users.
- A clearly identified plan by which telecommunications related projects can be identified by the TFO as they arise, and communicated to the AESO to assess. Based on the risk or urgency of the project, the AESO would then initiate a system project to address the need.

Combined, these deliverables will provide a framework to support ongoing effective and successful development and operation of the utility communications networks.
4.4 OPPORTUNITIES FOR COLLABORATIVE PLANNING

TFOs are currently taking advantage of the ability to share access to telecommunications network capacity where opportunities are available. New technologies utilized by the TFOs can be enhanced by extending collaboration between the AESO and the TFOs generating additional value from upcoming transmission investments. By looking at areas of potential synergy in the design, deployment, and management of the telecommunications system the TFOs can achieve operational benefits and cost savings through:

- Continuing to make unused capacity on core and spur routes available to other TFOs for route diversity and backhaul. Expanding the practice of using excess capacity on a network leg owned by another TFO provides greater reliability and efficiency for the operator while creating economies of scale for the system owner and making better use of the capital investment overall.

- Identification of opportunities to close gaps in fibre loops and establish new connections between existing networks for increased reliability and efficiency.

- Joint planning of the aggregate capacity required for each TFO's core telecommunications over the near and longer term. This would result in more accurate plans and more cost effective designs. Understanding the extent to which other TFOs may want to share capacity on a given transmission segment could improve the economics of the build and increase utilization of the asset. The AESO and the TFOs can increase the timeframe for collaborative planning and identify system related Teleprotection requirements and needed telecommunication upgrades. This will result in efficient use of investments and improve overall system reliability.

- Joint planning and collaboration could be expanded to telecommunications network management as well with TFOs benefiting from visibility of network segments where they share capacity on a given route. TFOs could also increase system reliability and potentially improve restoration plans by putting in place the processes and capacity for sharing a hot-failover operations center or rely on other TFOs for Networks Operations Centre (NOC) capability in the event of an emergency.
4.4.1 Technical and business drivers

In the late 1990s EPCOR and ENMAX developed a totally fibre optic ring around their service territories to facilitate their telecommunications needs providing protection, SCADA, operational voice and some mobile radio features. In the mid to late 1990s AltaLink and ATCO upgraded their aging analog microwave systems to high capacity digital microwave systems. As the demands for capacity on utility networks have increased, the industry has moved to an increased use of fibre optic cable. The AESO and the TFOs undertook a comparison of the use of fibre optic cable versus microwave in the utility network to determine which technology is best suited to meet the needs of the utility networks in Alberta.

The microwave vs. OPGW Comparison paper determined that where economically feasible, OPGW was the preferred network technology on any core network deployments being undertaken. The analysis took into account the planning and investment time horizons for transmission system projects and made this recommendation based on the following key points:

- An estimated 14 per cent incremental cost increase in telecommunications costs results in a 300 times increase in capacity. Even though the capital cost to implement OPGW is slightly higher than microwave, the benefit from increased capacity and lower operating cost will save money over the long term.

- OPGW requires no ongoing spectrum license fees and can utilize existing transmission rights-of-way, eliminating future land requirement costs.

- The existing utility microwave backbone is currently reaching capacity, and will require upgrades and retrofitting beginning in 2012 to accommodate network growth and to enable necessary improvements to system functionality. The much higher bandwidth available through OPGW or buried fibre will allow for both future growth as well as network optimization since TFOs can leverage existing network infrastructure without rebuilding that infrastructure to accommodate additional capacity.

- OPGW links will improve network redundancy and route diversity when installed with the existing transmission system microwave and fibre optic networks. This improves the capacity and reliability of the total network.

- Digital microwave electronics systems have a life expectancy of seven to 10 years. This is similar to the expected lifecycle of the electronics used to light OPGW fibre. Passive microwave components, such as antennas, towers, and waveguide all have lifecycles exceeding 25 years. An OPGW fibre optic cable, on the other hand, has a life expectancy of 35-plus years, thereby matching and surpassing the 35 year life span cost recovery mechanism of the steel transmission towers, and offers more efficiencies than can be found in the current microwave network. (Ref: AltaLink 2011-2013 TFO Tariff Depreciation Study)

- Deployment of new network switching technologies such as the migration from analog to digital microwave, take significant amounts of time. As such, migration programs can take up to five years to implement, from concept to completion. This time-period needs to be considered when planning for network deployments in the General Tariff Application (GTA)/budgeting process.
4.5 UTILITY NETWORK DEVELOPMENT PROJECTS

The following areas have been identified as requiring additional review and consideration for inclusion in the LTP to ensure that adequate and appropriate telecommunication systems are planned and budgeted to support the forecast demands on the network.

These major projects are summarized in Table 2 and listed in more detail on the following pages.

Table 2: Major network development project table

<table>
<thead>
<tr>
<th>Region/area</th>
<th>Project</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Edmonton</td>
<td>Keephills – Sundance – Genesee – Ellerslie – Summerside</td>
<td>Optical ground wire (OPGW) installation to meet latency requirements for protection system</td>
</tr>
<tr>
<td></td>
<td>North Calder – Poundmaker</td>
<td>AESO to review specifications and include OPGW between 37S North Calder and Poundmaker</td>
</tr>
<tr>
<td>Red Deer</td>
<td>17S Benalto – 63S Red Deer</td>
<td>Inclusion of OPGW on rebuild of the 138 kV lines to close gap between east and west HVDC lines</td>
</tr>
<tr>
<td></td>
<td>Multichannel service to Bighorn</td>
<td>Study and plan required to improve network reliability</td>
</tr>
<tr>
<td>Calgary</td>
<td>Foothills reinforcement (FATD)</td>
<td>OPGW to be considered for rebuild of several 240 kV lines</td>
</tr>
<tr>
<td></td>
<td>74S Janet – 102S Langdon</td>
<td>Inclusion of OPGW on new 240 kV line</td>
</tr>
<tr>
<td></td>
<td>ENMAX SS65 – 74S Janet</td>
<td>OPGW on rebuilt 911L will tie into existing ENMAX fibre ring</td>
</tr>
<tr>
<td>Camrose</td>
<td>Camrose Strome</td>
<td>Evaluation required for OPGW between east HVDC and Hanna area transmission redevelopment</td>
</tr>
<tr>
<td>B.C. Intertie</td>
<td>Coleman – Natal</td>
<td>OPGW to provide redundancy and meet NERC and ARS standards for BC Hydro interconnection</td>
</tr>
</tbody>
</table>

The installation of a north to south OPGW circuit concurrent with the construction of the High Voltage Direct Current (HVDC) lines provides the existing and long-term future expansion of AltaLink’s and ATCO’s communications and power system operations needs well into the future.

The installation of OPGW fibre on the West HVDC circuit will create a new communications link from Genesee to Langdon. The East HVDC line will run from the Heartland area to the West Brooks area. Installation of OPGW on this line creates two major north to south links that could be interconnected to create a fibre ring similar to the existing microwave backbone ring, but with significantly higher capacity. This creates a fibre optic loop that can become the next communications backbone with either fibre or microwave ingress and egress points.
4.6 MAJOR DEVELOPMENT PROJECTS

A high-level description of each of the major projects is provided below with an indication of the specific utility communications network development required.

4.6.1 Edmonton region

**Keephills – Sundance – Genesee – Ellerslie – Summerside**

The interconnection of the Keephills 3 unit in the spring of 2011 has identified a concern that the protection system in the area does not meet the latency requirements needed to provide adequate fault protection. While the Edmonton Area Protection Upgrade project may correct the situation AESO system studies indicate that absolutely no margin is available. Installation of fibre optic telecommunications will re-establish the operating margins.

**North Calder-Poundmaker**

The AESO Functional Specification (FS) for EPCOR’s new Poundmaker substation does not specifically request that fibre optics be installed to provide the telecommunications required. Given the nature of EPCOR's fibre optic ring, the AESO will review the FS to and include the fibre optic requirement between 37S North Calder and the new Poundmaker station.

4.6.2 Red Deer area

**17S Benalto – 63S Red Deer**

The Red Deer Area plan identifies several transmission upgrades to the 138 kV system including the replacement of 648L between 63S Red Deer and 580S Sylvan Lake, and 637L between 580S Sylvan Lake and 17S Benalto. Including OPGW on the rebuilds of 648L and 637L could provide a mid province fibre optic interconnection between the east and west HVDC line. A detailed review of the final route selection for the East and West HVDC lines will be studied to determine economic benefits of closing the gap. Regardless the introduction of a fibre optic connection between Benalto and Red Deer will enhance the telecommunications system to allow maintenance on the microwave system to happen without causing curtailments to generation in the Keephills-Genesee-Sundance region as is now the case.

**Multichannel service to Bighorn**

The telecommunication system between Benalto and the Bighorn hydro plant has long been susceptible to communication failures due to path failure. Currently a commercial leased line provides back-up communications. The Bighorn hydro plant is an important provider of Blackstart services for the AESO System Restoration Plan. Based on historical failure rates, it is unlikely that the commercial leased line would be available during a province wide blackout. A detailed study and project plan is required to explore options to improve the telecommunication in the area.
4.6.3 Calgary area

Foothills Area Transmission Development (FATD)
The Foothills Area Transmission Development anticipates the rebuild and reconfiguration of several 240 kV lines in the Calgary area.

74S Janet – 102S Langdon
FATD anticipates the construction of a new 240 kV double circuit line between 74S Janet and 102S Langdon. Inclusion of OPGW will provide fibre optic communications and in conjunction with the Ware Junction to Langdon line close the provincial fibre optic backbone between the East and West HVDC Lines across the southern portion of the province.

ENMAX SS65 – 74S Janet
The rebuild of 911L from Janet to the new ENMAX SS65 will provide a fibre optic connection for AltaLink’s protection of 240 kV circuits feeding the substation.

4.6.4 Camrose area

Camrose – Strome
Currently there are no transmission system projects contemplated that provide an opportunity to establish a fibre optic telecommunications interconnection between the East HVDC line and the fibre optics being installed as a part of the Hanna Area Transmission Development. Once the final route for the East HVDC line is determined a detailed review of the area telecommunications needs will be undertaken. If a reasonable and economic opportunity can be identified a project to establish this cross tie should be undertaken.

4.6.5 Southern Alberta Transmission Reinforcement (SATR)

Coleman – Natal
The recent NERC Balancing Authority Audit and the NERC Transmission Owner Audits have identified that the telecommunications system for the BCH Interconnection does not have redundant telecommunications. Transmission upgrades included in the Southern Alberta Transmission Reinforcement (SATR) project identify a new 138 kV substation, complete with a phase shifting transformer (PST) in the Coleman area. Installation of fibre optics for teleprotection and control could allow full compliance with NERC and Alberta Reliability Standards. It is recommended that the AESO work with BC Hydro to explore a fibre optic solution to the NERC compliance audits.

4.6.6 Potential communications network projects

There are a number of communication network projects that have been flagged by the TFOs as having potential deficiencies relative to requirements implied by the LTP. These projects will be reviewed by the AESO and may result in the development of Needs Identification Documents, as appropriate, for submission to the AUC.
5.0 Conclusion

The Telecommunications Long-term Plan is driven by the AESO’s mandate to ensure the safe, reliable, and economic operation of the AIES. It also supports the Provincial Energy Strategy for Alberta’s ongoing access to an efficient, competitive, and reliable transmission system. When combined with identification of new opportunities for collaboration between the AESO and the TFOs, provision of a utility telecommunications system framework affords continuing efficient investment in Alberta’s utility telecommunications system, thereby supporting the AIES as it evolves to meet the needs of Albertans.

The AIES as defined in the 2011 Long-term Transmission Plan relies heavily on a robust and complex communications system to provide the wide range of applications required for it to function effectively. The Telecommunications Plan represents work that is already underway, and will be used to help shape policy and process, keeping the design of utility communications networks tightly aligned with the goals and requirements of the transmission system. Having the Telecommunication Plan mirror the planning horizon of the Plan will ensure that communications network investment decisions support both near and long term expectations for growth.

The AESO has and will continue to work closely with stakeholders to support the implementation of the Long-term Telecommunications Plan to ensure potential benefits are identified and realized. The planning and project review process as defined within the Telecommunications Plan will continue to evolve and improve as the linkage between transmission and telecommunication requirements is more clearly defined and established through effective long-term planning.
6.0 Glossary

**Advanced Metering Infrastructure (AMI)** – is comprised of state-of-the-art electronic/digital hardware and software which combine interval data measurement with continuously available remote communications. These systems enable measurement of detailed, time-based information and frequent collection and transmittal of such information to the service provider.

**Alberta Interconnected Electric System (AIES)** – All electric energy transmission facilities and all distribution systems in Alberta that are interconnected. The Alberta Electric System Operator (AESO) provides fair and open access to the AIES for generation and distribution companies and large industrial consumers of electricity, and contracts with transmission facility owners to acquire transmission services and provide customer access.

**Alberta Reliability Standards (ARS)** – The AESO currently operates to NERC and Western Electricity Coordinating Council (WECC) reliability standards through the adoption of Alberta Reliability Standards.

**Critical Transmission Infrastructure projects (CTI)** – major infrastructure expansions as more fully described in the AESO's Long-term Transmission System Plans.

**Demand Response (DR)** – is similar to dynamic demand mechanisms to manage customer consumption of electricity in response to supply conditions, for example, having electricity customers reduce their consumption at critical times or in response to market prices. The difference is that demand response mechanisms respond to explicit requests to shut off, whereas dynamic demand devices passively shut off when stress in the grid is sensed. Demand response can involve actually curtailing power used or by starting on site generation which may or may not be connected in parallel with the grid.

**Distribution Automation (DA)** – is real-time adjustment to changing loads, generation, and failure conditions of the distribution system, usually without operator intervention. This necessitates control of field devices, which implies enough information technology (IT) development to enable automated decision making in the field and relaying of critical information to the utility control center.

**Distribution Facility Owners (DFOs)** – Owners and operators of distribution facilities.

**Electric Utilities Act (EUA)** – This Act provides the underlying authority for the restructure of the electric industry in Alberta.
**Energy Management System (EMS)** – is a system of computer-aided tools used by operators of electric utility grids to monitor, control, and optimize the performance of the generation and/or transmission system. The monitor and control functions are known as SCADA; the optimization packages are often referred to as “advanced applications”.

**General Tariff Application (GTA)** – A filing made by a TFO to the AUC defining capital expenditures related to the expansion and operation of electrical transmission facilities.

**High Voltage Direct Current (HVDC)** – electric power transmission system that uses direct current for the bulk transmission of electrical power, in contrast with the more common alternating current (AC) systems.

**Independent Power Producers (IPPs)** – are entities, while though not a public utility, but which owns facilities to generate electric power for sale to utilities and end users. IPPs may be privately-held facilities, corporations, cooperatives such as rural solar or wind energy producers, and non-energy industrial concerns capable of feeding excess energy into the system.

**Latency** – in a network, a synonym for *delay*, is an expression of how much time it takes for a packet of data to get from one designated point to another. In some usages latency is measured by sending a packet that is returned to the sender and the round-trip time is considered the latency.

**Long-term Telecommunications Plan** – Prepared by the AESO to ensure that the required telecommunications infrastructure will be in place to support the development defined in the Long-term Transmission System Plan.

**Long-term Transmission System Plan** – Prepared by the AESO to project and plan for the future electrical needs of the province of Alberta.

**Mobile Radio** – wireless communications systems and devices which are based on radio frequencies, and where the path of communications is movable on either end.

**North American Electric Reliability Corporation (NERC)** – An organization with a mandate to ensure that the bulk power system in North America is and remains reliable.

**OPX** – Operation Voice Communications

**Operational Voice** – to seamlessly integrate analog voice communication into a digital data network
**Optical Ground Wire (OPGW)** – (also known as OPGW or, in the IEEE standard, an optical fibre composite overhead ground wire) is a type of cable that is used in the construction of electric power transmission and distribution lines. Such cable combines the functions of grounding and communications. An OPGW cable contains a tubular structure with one or more optical fibres in it, surrounded by layers of steel and aluminum wire. The OPGW cable is run between the tops of high-voltage electricity structures. The conductive part of the cable serves to bond adjacent structures to earth ground, and shields the high-voltage conductors from lightning strikes. The optical fibres within the cable can be used for high-speed transmission of data, either for the electrical utility's own purposes of protection and control of the transmission line and/or for the utility's own voice and data communication.

**Phasor Measurement Unit (PMUs)** – measures the electrical waves on an electricity grid to determine the health of the system. In power engineering, these are also commonly referred to as synchrophasors and are considered one of the most important measuring devices in the future of power systems. A PMU can be a dedicated device, or the PMU function can be incorporated into a protective relay or other device.

**Supervisory Control and Data Acquisition (SCADA)** – generally refers to industrial control systems; computer systems that monitor and control industrial, infrastructure, or facility-based processes, such as power generation and distribution networks.

**Smart grid** – is a form of electricity network utilising digital technology. A Smart grid delivers electricity from suppliers to consumers using two-way digital communications to control appliances at consumers' homes; this could save energy, reduce costs and increase reliability and transparency. The “Smart grid” is envisioned to overlay the ordinary electrical grid with an information and net metering system that includes smart meters. Smart grids are being promoted by many governments/utilities as a way of addressing energy independence, global warming and emergency resilience issues.

**Teleprotection** – protective relays communicate with each other to clear transmission system faults, increase fault sensitivity, and restore power, therefore, avoiding potentially expensive damage to a substation or transmission grid.

**Transmission Facility Owner (TFO)** – Owners and operators of transmission facilities.

**Utility Communication networks** – are the primary component in maintaining both normal and emergency operations of the electricity system via an ultra-reliable utility telecommunications system.
Utility Telecommunications Systems – Utility Telecommunications Networks – The utility telecom network is a private telecommunications network typically built and operated by utilities themselves, specifically to support the operation and maintenance of the electrical power system. This includes providing emergency voice and data services when utility service interruptions occur – something that cannot be guaranteed by commercial providers. The network, comprised of telecom infrastructure (towers, microwave radio, fibre optics, SONET/MPLS, and land-mobile radio) provides mission critical services such as teleprotection, SCADA, emergency voice and land-mobile radio. These services support the safe, efficient delivery of energy from generators, through transmission, to distribution and on to utility customers.

Western Electricity Coordinating Council (WECC) – An organization formed to coordinate and promote electric system reliability for the system that interconnects Alberta, B.C., 14 western U.S. states and part of one Mexican state.
Appendix K: Part 1
The Value of Transmission

INTRODUCTION

The AESO is charged with the responsibility for planning the transmission system to ensure that adequate transmission capacity is in place in advance of need. In Alberta’s deregulated single price wholesale energy market, this means that transmission plans must ensure all generators have equal opportunity to fully compete in the market and all loads can withdraw power whenever and wherever it is required. A lack of transmission capacity should neither hinder economic development decisions nor should it determine winners or losers in the wholesale market. Only an adequate, open, non-discriminatory transmission system can achieve these objectives.

PLANNING FOR UNCERTAINTY

Long-term transmission planning is inherently uncertain. Transmission investment decisions must anticipate needs decades into the future because transmission infrastructure has an investment life of 30 to 40 years and new developments require five to eight years to plan and build. In addition to reliability requirements, transmission plans must consider trends in economic development, population growth, technological advancement, environmental regulation, and trends in neighbouring jurisdictions in order to arrive at robust solutions that stand the test of time. Given the large number of variables involved, accurate and complete forecasting over the long economic life of transmission assets is not possible, and commitment decisions must be made through the use of scenario analysis to arrive at plans that can adapt to a broad range of potential future outcomes.

Prior to deregulation, integrated utilities planned both generation and transmission development to meet anticipated demand. While there was significant long-term uncertainty associated with the timing and location of new load, the timing and location of new generation was under the control of the system planners. In Alberta’s deregulated market, transmission planning is characterized by additional uncertainty because the timing and location of new generation additions and retirements are private investment decisions that are not under the control of the AESO.
With the timing and location of new generation additions and retirements no longer under its control and with the large number of variables that must be considered, the AESO’s transmission plans must be robust and flexible so that the configuration of the system does not constrain future economic development decisions. In recognition of this uncertainty, the 2003 Transmission Development Policy directs the AESO to be proactive in its planning and build transmission in advance of need since market signals will not provide timely indicators for development given the long lead time associated with transmission projects. The use of project milestones enables prudent timing of transmission developments to ensure consumers receive maximum value from transmission investments by timing the construction of incremental phases of projects to align investment with anticipated need dates.

As policies evolve and as fuel source preferences change over time, adequate transmission capacity facilitates changes in the generation fleet as investors choose new types and locations of generation based on the availability of new fuels. Wind and hydro power provide low-cost, carbon-free energy that complements thermal sources such as natural gas and coal. A diverse mix of generation sources provides economic and environmental benefits and enabling this optionality is one of the key objectives of the planning process.

The long lead time and economic life associated with transmission projects results in an asymmetric risk profile for transmission development – the cost of building insufficient transmission capacity far outweighs the cost of building excess transmission capacity.

If future expectations of need turn out to have overestimated the amount of transmission capacity required, the consequence is the capital and maintenance cost of the transmission capacity, which is essentially fixed and predictable over time. In addition, if transmission capacity in the future exceeds the anticipated need, there are several benefits that may be realized, such as the deferral of future transmission expansions, continued certainty for generation and load developers that transmission capacity and power will be available when and where required, the smooth functioning of the wholesale energy market without constraint, and reduced system losses due to reasonable line loading.

If future expectations of need turn out to have underestimated the amount of transmission capacity required, the consequences are much larger. Economic development may be deferred or reduced due to the lack of sufficient transmission capacity. Increased congestion will undermine the efficiency of the wholesale market, increasing the delivered cost of power to consumers, reducing the competitiveness of generators and potentially discouraging the entry of new market participants. System inefficiency will increase through increased line loading, which will result in greater losses and increased use of non-wires solutions such as transmission must-run (TMR) and remedial action schemes, to compensate for inadequate transmission capacity in constrained areas. The sum of these consequences is far greater than the fixed cost associated with building excess transmission capacity.

In determining the appropriate size of incremental transmission additions, the most effective hedge against future uncertainty is to plan for high demand and generation growth scenarios to ensure sufficient capacity margin and minimize the significant consequences associated with insufficient transmission capacity.
The Impact of Transmission Constraints on the Wholesale Electricity Market

Alberta’s wholesale market design utilizes a single clearing price for all power regardless of the location from which power is delivered. To support this design, transmission must be available to all generation and load customers in a non-discriminatory manner and with sufficient capacity to ensure that neither load nor generation is constrained. This is necessary to eliminate locational pricing advantages caused by transmission congestion and expose every generator to full competition from every other generator in the system. This encourages all generators to offer close to their marginal cost of production in order to increase their chance of being dispatched ahead of their competitors. This provides consumers the lowest delivered cost of power. The full benefits of the wholesale market can therefore only be realized with an unconstrained transmission system.

However, the transmission system in Alberta is currently constrained. In areas of mild to moderate constraint, the full output of lower-price generators cannot reach consumers, which results in the dispatch of higher-price generators to meet demand, thereby raising the overall price of power. In areas of significant constraint, such as in northwestern Alberta, the AESO must contract for the right to use local generation to meet local demand since insufficient transmission capacity is available to meet local demand from the bulk transmission system. The use of generators in this manner is referred to as TMR service and often results in the dispatch of more expensive generators to meet demand than would be the case if sufficient transmission capacity was available. These inefficiencies undermine the effectiveness of the energy market and increase the delivered cost of power to all consumers.

The cost of constrained generation can be significant, particularly when sufficient amounts of low-priced generation are unable to meet demand and, instead, high-price generated is requested to meet that demand. This results in a higher average price of power.

Figure 1 demonstrates how a small transmission constraint of 100 megawatts (MW) of supply can result in a large increase in the market price. In this example, if the dispatch level was 9,500 MW without the constraint, the market price would increase over $400/megawatt-hour (MWh) with a 100 MW constraint.

Assuming that this congestion persists for only 40 hours of the year (about 0.5 per cent of the time) the cost of serving this 9,500 MW of demand would increase by $160 million.

This simple example shows that consumers bear the direct cost burden of congestion by paying higher energy prices than otherwise would have resulted in a congestion-free system.
The AESO has begun to expand upon this concept to further estimate the impact constraints may have on prices. Furthermore this initial analysis takes into account various dispatch levels in the merit order. If in the example presented in Figure 1 the dispatch level was 9,150 MW then the price increase due to the 100 MW of constraint would have been $12.60/MWh. Figure 2 illustrates the results of this analysis using 2010 merit orders and constraints of five through 500 MW. It is noted that at low levels of constraints, there is less chance that there will be a significant price differential; at higher levels of constraints, there may be upwards of a 12 per cent chance that the price may increase by over $250/MWh (red and dark red region of the graph). To read the figure, the x-axis is the distribution of price increases given a certain level of constraint, the y-axis is the constraint level, and the colours represent the range of price increases. The right-hand legend illustrates the colours associated with differing price increases.

Data from recent years further illustrates the cost of transmission congestion to consumers. Figure 3 illustrates the estimated costs to consumers for levels of congestion seen from 2008 to 2010. This is based on an analysis focusing on how much the power price increases due to a transmission system constraint, resulting in higher price generation being dispatched. This analysis also includes the costs associated with TMR. For similar levels of constrained generation as observed over the past three years, it is estimated that energy charges to consumers are nearly $1.6 billion higher than they would be in the absence of constrained generation.\(^1\) Further details of this analysis are available in Part 2 of this appendix.

\(^1\) This analysis is a theoretical statistical illustration only, based on unusually high constraints observed from 2008 to 2010 including a rare storm event and temporary but significant construction activity related to transmission enhancement. It is not a forecast but it is designed to demonstrate the potential extreme impacts on the market should transmission requirements be underestimated.
Figure 2: Distribution of price differentials based on various levels of constraints to the EMMO (2010 EMMOs used for analysis)

Figure 3: Actual and estimated cost of transmission congestion events equivalent to those observed from 2008 to 2010
To date, investor confidence that the transmission system will be capable of allowing generation to participate in the market has already resulted in significant generation investment in the province. As Figure 4 illustrates, there have been significant new generation additions in Alberta since the move to a deregulated market and there are significant new generation investments planned. The economics of these generation developments are dependent upon their ability to connect to load and participate in the energy market. Adequate transmission capacity facilitates these generation additions and is essential to ensuring that they are able to fully and fairly compete in the wholesale market with incumbent participants.

Figure 4: Generation additions

Figure 4 illustrates the significant new generation additions in Alberta since the move to a deregulated market and the significant new generation investments planned. The economics of these generation developments are dependent upon their ability to connect to load and participate in the energy market. Adequate transmission capacity facilitates these generation additions and is essential to ensuring that they are able to fully and fairly compete in the wholesale market with incumbent participants.

Given the current estimated cost to consumers of transmission congestion and the significant amount of new generation capacity that is projected to be built over the coming decades, investments in transmission capacity now that reduces or eliminates congestion will provide value for Alberta consumers for decades to come.
TRANSMISSION ENABLES ECONOMIC DEVELOPMENT

The proposed transmission upgrades outlined in the LTP offer a strong value proposition to Alberta consumers in terms of both foregone costs associated with transmission congestion and in terms of economic, investment and societal benefits and opportunities.

Most, if not all, businesses are dependent upon a reliable source of electricity. Transmission service tends to be more reliable and cost effective at the consumer level than generation so it is logical for businesses and industries to connect to the transmission system than to build their own supply. Confidence that the transmission system will be able to serve the needs of business development creates greater confidence for investors and improves the overall investment climate of the province, which facilitates greater long-term economic growth and prosperity.

As Figure 5 illustrates, the economy of Alberta, as measured by Gross Domestic Product (GDP), is expected to grow strongly over the next decade. The investment and development associated with this economic growth is dependent upon a reliable transmission grid that can serve the needs of growing businesses and industries. Investors assume adequate transmission capacity will be available to accommodate their plans for development.

Figure 5: Forecasts of real GDP growth in Alberta

![GDP Growth Chart](chart.png)

Source: The Conference Board of Canada, IHS Global Insights, Alberta Finance and Enterprise

This strong GDP growth translates to significant capital investment in Alberta that provides both direct and indirect benefits to Albertans through employment, services, tax revenues, and resource rents (royalties). As Table 4 illustrates, over $180 billion of investment is expected in just the next two years across various sectors in Alberta.
Table 1: Alberta Finance and Enterprise inventory of major projects (April 2011) valued at $5 million or greater

<table>
<thead>
<tr>
<th>Project sector</th>
<th>Number of projects</th>
<th>Value of projects ($ millions)</th>
<th>Fraction of total project expenditure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Agriculture and related</td>
<td>8</td>
<td>$238</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Biofuels</td>
<td>12</td>
<td>$1,450</td>
<td>1%</td>
</tr>
<tr>
<td>Chemicals and petrochemicals</td>
<td>4</td>
<td>$119</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Commercial/retail</td>
<td>55</td>
<td>$8,478</td>
<td>5%</td>
</tr>
<tr>
<td>Commercial/retail and residential</td>
<td>8</td>
<td>$2,668</td>
<td>1%</td>
</tr>
<tr>
<td>Forestry and related</td>
<td>7</td>
<td>$267</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Infrastructure</td>
<td>280</td>
<td>$18,052</td>
<td>10%</td>
</tr>
<tr>
<td>Institutional</td>
<td>123</td>
<td>$7,616</td>
<td>4%</td>
</tr>
<tr>
<td>Manufacturing</td>
<td>6</td>
<td>$665</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Mining</td>
<td>5</td>
<td>$4,945</td>
<td>3%</td>
</tr>
<tr>
<td>Oil and gas</td>
<td>7</td>
<td>$1,440</td>
<td>1%</td>
</tr>
<tr>
<td>Oilsands</td>
<td>61</td>
<td>$109,604</td>
<td>58%</td>
</tr>
<tr>
<td>Other industrial</td>
<td>6</td>
<td>$1,480</td>
<td>1%</td>
</tr>
<tr>
<td>Pipelines</td>
<td>29</td>
<td>$7,516</td>
<td>4%</td>
</tr>
<tr>
<td>Power</td>
<td>39</td>
<td>$13,704</td>
<td>7%</td>
</tr>
<tr>
<td>Residential</td>
<td>87</td>
<td>$4,760</td>
<td>3%</td>
</tr>
<tr>
<td>Telecommunications</td>
<td>2</td>
<td>$656</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Tourism/recreation</td>
<td>94</td>
<td>$3,894</td>
<td>2%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>833</strong></td>
<td><strong>$187,549</strong></td>
<td><strong>100%</strong></td>
</tr>
</tbody>
</table>

Source: Alberta Finance and Enterprise

In the longer term, Peters & Co, in their *Oilsands Overview: Winter 2011*, forecast total risked capital expenditures of $180 billion in the oilsands alone over the next 10 years.

Another area of significant growth is employment. According to The Conference Board of Canada, approximately 660,000 jobs are expected to be created in Alberta between 2011 and 2030.
As this economic data indicates, Alberta is poised for significant economic development over the next 10 to 20 years and a reliable supply of electricity cannot be sustained without enhancing and expanding the existing transmission system. New infrastructure must be in place before demand arises so investment, market access and economic development are not compromised.

Investment decisions are based in part on confidence that adequate transmission capacity will be available when and where it is required. For business or industry, decisions on whether to locate in Alberta and to expand existing operations can only be made when there is reasonable assurance of access to an adequate supply of electricity at reasonably predictable and stable future prices. A robust transmission system provides confidence to investors that they can count on access to the transmission system before making investment decisions. Given the long lead times and economic lives associated with transmission infrastructure projects, these facilities must be developed now to accommodate the needs of Albertans far into the future.

Figure 6: Employment forecast

Source: The Conference Board of Canada, AESO
The transmission system investment over the next decade will enable much of the capital investment in Alberta and represents significant value to Albertans in the same way as investments in highways and other infrastructure projects do. Highways, public health systems, sewer and water systems, and transmission infrastructure are all public goods that provide a foundation for economic development and a high quality of life. Since these projects are not seen as directly generating revenue, they are often viewed on the basis of their costs alone. However, since public infrastructure is necessary to enable economic development and support a high standard of living, it must be viewed in the context of the economic development and social value it enables. One cannot imagine the development of today’s modern economy without our vast system of interconnected roads, highways, and railways that make efficient transportation of goods and services possible and affordable. Transmission infrastructure is even more pervasive as it plays a role in virtually every aspect of modern industrialized society.
COGENERATION

Some oilsands sites intend to rely on the transmission system for their power needs while others are planning install on site cogeneration while using the transmission grid as a back-up supply source. In most cases, sites with cogeneration tend to sell their excess power to the grid. In all cases, these sites are relying on adequate transmission capacity either to meet their electricity needs or to sell their excess power generation via the wholesale market.

Unfortunately, because the pace of oilsands development has exceeded the pace of transmission system upgrades, there have been some cases where oilsands developers’ plans have been affected by the availability of transmission capacity. Developers can make economic choices between self-supply via cogeneration, supply from the transmission system, or a combination of both only if adequate transmission capacity is expected to be available in their project planning horizon. If adequate transmission capacity is not anticipated, the options available to developers may be constrained leading to suboptimal development economics, such as the installation of cogeneration when supply from the transmission system would have been more economic. A developer’s decision to build cogeneration should not be based upon the availability of transmission capacity; it should be based on economic merit with the confidence that there will be a reliable transmission system available to meet their needs regardless of which option they choose. In addition, even developers who choose to self-supply via cogeneration require transmission capacity for supply redundancy when their cogeneration facilities are out of service for planned and unplanned maintenance.

Existing cogeneration facilities are currently affected by transmission congestion. Since the northeast portion of the province is currently transmission constrained, oilsands sites with cogeneration surplus are often forced to curtail their supply to the grid. This impacts cogeneration owners through foregone power sales that negatively impact the economics of their operations. This also impacts Alberta consumers through the inability to access extremely efficient and cost-effective power provided by cogeneration facilities.
ECONOMIES OF SCALE

Transmission investments are often described as lumpy, meaning that transmission cannot be acquired in small increments but must be built in large, discrete units. These units are based on voltage levels, typically 138 kilovolts (kV), 240 kV, and 500 kV, with the cost of transmission facilities increasing with increasing voltage level. Therefore, transmission plans are constrained by these increments and cannot be optimized for specific voltage levels, such as 371 kV, that may produce the most economically efficient outcome by aligning transmission capacity precisely with demand.

Given this characteristic, major transmission builds are cyclical and periods of large investment are typically followed by long periods of relative stasis as the large new incremental capacity serves demand for many years before significant new capacity is required. Alberta is entering a new transmission investment cycle as the large capacity additions that were made 20 to 30 years ago are now largely used up and new capacity is required to ensure the continued pace of provincial economic development. Figure 7 below illustrates the cyclical nature of transmission investment in Alberta based on historic and projected transmission investments.

**Figure 7: Historic and projected transmission investment based on 2009 LTP**

*Transmission investment adjusted for system load (2009 $ millions/MW load)*

Source: AltaLink
The cost of transmission increases with voltage level. However, higher voltage transmission lines generally require less land per MW-mile than lower voltage transmission lines. This means that more power can be carried over less land if the transmission system is built to higher voltage levels. It also means that there are significant economies of scale that can be obtained from building higher voltage transmission facilities as the cost per MW-mile of transmission decreases with increasing voltage level. The Edison Electric Institute (EEI) examined this characteristic in its 2008 report "Transforming America’s Power Industry: The Investment Challenge 2010-2030". Table 2 illustrates the relationship EEI found between voltage and cost per gigawatt-mile based on a survey of U.S. transmission projects.

### Table 2: Relationship between transmission voltage and cost (2008 $ U.S.)

<table>
<thead>
<tr>
<th>Voltage (kV)</th>
<th>Cost ($1,000/mile)</th>
<th>Capacity (MW)</th>
<th>Cost ($ millions/GW-mile)</th>
</tr>
</thead>
<tbody>
<tr>
<td>230</td>
<td>$2,077</td>
<td>500</td>
<td>$5.46</td>
</tr>
<tr>
<td>345</td>
<td>$2,539</td>
<td>967</td>
<td>$2.85</td>
</tr>
<tr>
<td>500</td>
<td>$4,328</td>
<td>2,040</td>
<td>$1.45</td>
</tr>
<tr>
<td>765</td>
<td>$6,578</td>
<td>5,000</td>
<td>$1.32</td>
</tr>
</tbody>
</table>

This characteristic of transmission infrastructure means there are significant economic and regulatory efficiencies to be gained from sizing facilities for anticipated demand 20 to 30 years into the future and accepting low near-term utilization rates than sizing facilities for near-term utilization rates and returning multiple times to expand existing corridors or create new corridors to build small capacity increments to accurately align demand and transmission capacity over time. Building in advance of need leverages the economies of scale that transmission provides.

As Alberta grows and develops its vast bounty of natural resources, demand will increase significantly and the transmission system must evolve in anticipation of this demand. Moving to a 500 kV bulk system backbone from a 240 kV backbone as new upgrades are built will not only provide significant near-term benefits by alleviating transmission congestion but it will enable efficient system operation for decades to come and allow Alberta to keep pace with world demand for its resources in the future. The economies of scale associated with transmission provides consumers with excellent long-term value from investments in 500 kV transmission facilities.
TRANSMISSION COSTS

The cost of transmission, especially new upgrades to the system, are a concern for all Albertan ratepayers. Due to the inevitable required additions to the system, transmission tariffs will rise. It is, however, important to keep transmission costs in perspective. It is also important to remember that the majority of proposed transmission upgrades are subject to regulatory needs approval via the AUC. It is only Critical Transmission Infrastructure (CTI) that is not subject to regulator needs approval and actions are being undertaken to ensure that the costs of all projects are carefully monitored and minimized.

The fact remains that the costs of transmission are not prohibitively high. In fact, the estimated cost of proposed transmission upgrades is below historical levels as illustrated in Figure 7.

Transmission investment tends to be cyclical because large transmission projects utilize economies of scale which, in the long run, lower their marginal costs. However, large transmission projects need to be built in advance of need so there tends to be a period of excess capacity. This excess capacity assures load and generation entities that there is sufficient grid capacity to serve their needs. Years of strong population and economic growth have increased the demand for electricity and for transmission. The transmission capacity built in the 1970s and 1980s has now been used up and it is necessary to once again expand the system. The transmission upgrades outlined in the LTP will create the transmission capacity need to serve load and generation for years to come and will enable expected economic development, job creation and population growth.
Appendix K: Part 2
Impact of Transmission Constraints on the Wholesale Electricity Market

**TABLE OF CONTENTS**

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Executive summary</td>
<td>454</td>
</tr>
<tr>
<td>Introduction</td>
<td>456</td>
</tr>
<tr>
<td>Existing transmission constraints</td>
<td>457</td>
</tr>
<tr>
<td>Transmission must-run (TMR)</td>
<td>458</td>
</tr>
<tr>
<td>Constrained down generation (CDG)</td>
<td>458</td>
</tr>
<tr>
<td>Price impact of constrained generation</td>
<td>461</td>
</tr>
<tr>
<td>Estimates of the total market impact of constraints</td>
<td>466</td>
</tr>
<tr>
<td>Next steps</td>
<td>468</td>
</tr>
<tr>
<td>Conclusions</td>
<td>468</td>
</tr>
</tbody>
</table>
EXECUTIVE SUMMARY

Alberta’s wholesale electricity market design utilizes a single clearing price (pool price) for all power regardless of the location from which power is delivered. To support this design, transmission must be available to all generation and load customers in a non-discriminatory manner and with sufficient capacity to ensure that each generator is exposed to full competition from all other generators, regardless of geographic location. When in-merit generators are constrained, their output cannot reach the market and higher priced generators must be dispatched to meet demand. Additionally, the existence of constraints influences generator offer behaviour because it can provide a competitive locational advantage to certain generators. The net effect is increased costs to consumers since pool prices increase for all power consumed. In geographic locations with chronically insufficient transmission capacity, additional costs are incurred due to the use of costly out-of-market mechanisms that must be invoked to ensure that reliable supply is available.

For the purposes of this evaluation, two classes of constraints have been identified:

- Transmission must-run (TMR) – generation required to be online and operating to ensure reliability in specific areas of Alberta where there is insufficient local transmission capacity to support local demand and system reliability.
- Constrained down generation – this includes generation that has been prevented from reaching the market due to either small levels of constraint that occur frequently at varying locations across the entire transmission system or due to significant contingencies, such as storms or outages, the effects of which are exacerbated by insufficient transmission capacity margin.

To estimate the impact constrained generation has on pool price, a structural analysis was performed using historic merit orders. Given a certain dispatch level in the energy market, the analysis determined the difference in price between an unconstrained merit order and a constrained merit order. The results indicate the potential risk there is to energy prices when generation is constrained. For example: For a constraint of 170 MW of generation in the merit order, there is approximately a 5 per cent potential that prices for power would increase by $250 per megawatt-hour (MWh) or more.
Using this approach, the market value (incremental price change multiplied by total demand) due to higher pool prices resulting from constraints has been estimated for levels of constraint commensurate with historically observed levels of constraint. Using this approach, the market value (incremental price change multiplied by total demand) due to higher pool prices resulting from constraints has been estimated for levels of constraint commensurate with historically observed levels of constraint. Over time, there has been an increasing trend in the frequency of constraints, their location, and pool price impact. This trend is expected to continue until incremental transmission capacity is added to the system. The estimated costs to consumers resulting from these pool price impacts are significant. For similar levels of constrained generation as observed over the past three years it is estimated that energy charges to consumers are nearly $1.6 billion higher than they would be in the absence of constrained generation.¹

Table 1 provides a summary of the results. Significant costs are incurred due to constrained generation, particularly in response to major events, such as Keephills-Ellerslie-Genesee (KEG) area outages, where significant amounts of generation are prevented from reaching the market.

Table 1: Summary of system costs of transmission constraints

<table>
<thead>
<tr>
<th>Year</th>
<th>TMR Volume (GWh)</th>
<th>TMR Cost ($ millions)</th>
<th>Volume analyzed (GWh)</th>
<th>Estimated cost ($ millions)</th>
<th>Volume analyzed (GWh)</th>
<th>Estimated cost ($ millions)</th>
<th>Volume analyzed (GWh)</th>
<th>Estimated cost ($ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>983</td>
<td>$43.40</td>
<td>285.8</td>
<td>$827.30</td>
<td>264.8</td>
<td>$760.70</td>
<td>21</td>
<td>$66.60</td>
</tr>
<tr>
<td>2009</td>
<td>1,018</td>
<td>$26.40</td>
<td>55.4</td>
<td>$75.50</td>
<td>16.3</td>
<td>$21.50</td>
<td>39.1</td>
<td>$54.00</td>
</tr>
<tr>
<td>2010</td>
<td>792</td>
<td>$26.10</td>
<td>577</td>
<td>$691.30</td>
<td>467.7</td>
<td>$547.70</td>
<td>109.3</td>
<td>$143.60</td>
</tr>
</tbody>
</table>

¹ This analysis is a theoretical statistical illustration only, based on unusually high constraints observed from 2008 to 2010 including a rare storm event and temporary but significant construction activity related to transmission enhancement. It is not a forecast but it is designed to demonstrate the potential extreme impacts on the market should transmission requirements be underestimated.
INTRODUCTION

Alberta’s wholesale market design utilizes a single clearing price (pool price) for all power regardless of the location from which power is delivered. To support this design, transmission must be available to all supply and load customers in a non-discriminatory manner and with sufficient capacity to ensure that neither load nor generation is constrained. This is necessary to eliminate geographical pricing advantages caused by transmission congestion and expose every generator to full competition from every other generator in the system. This encourages all generators to offer close to their marginal cost of production in order to increase their chance of being dispatched ahead of their competitors. This will provide consumers the lowest delivered cost of power. The full benefits of the wholesale market can therefore only be realized with an unconstrained transmission system.

However, the transmission system in Alberta is currently constrained. In areas of mild to moderate constraint, the full output of lower priced generators cannot reach consumers which results in the dispatch of higher priced generators to meet demand, thereby raising the overall price of power. In areas of significant constraint, such as in northwest Alberta, the AESO must contract for the right to use local generation to meet local demand since insufficient transmission capacity is available meet local demand from the bulk transmission system. The use of generators in this manner is referred to as transmission must-run (TMR) service and often results in the dispatch of more expensive generators to meet demand than would be the case if sufficient transmission capacity was available. These inefficiencies undermine the effectiveness of the energy market and increase the delivered cost of power to all consumers.

The cost of constrained generation can be significant, particularly when sufficient amounts of low priced generation cannot be used to meet demand. Figure 1 illustrates how a 100 MW constraint on the offer curve may, depending on the dispatch location, result in a significant increase in the pool price, and hence the cost of energy. In the example, because of the “hockey-stick” shape of the energy market merit order it is possible for the removal of 100 MW of low priced supply to result in a pool price increase of over $400/MWh. Due to the relatively inelastic nature of demand, there is only a small amount of response to the increased price.

To understand how Alberta’s pool price is impacted by constrained generation a structural analysis was preformed which illustrates how pool prices increase in response to constraints to lower priced supply. The results of the analysis are utilized to estimate the market impact that constraints similar to those observed over the past three years would have.
Currently there are two main categories of transmission constraints on the system – TMR and constrained down generation. In northwestern Alberta, generation is typically contracted to supply the region, independent of the energy market merit order, due to insufficient local transmission capacity to meet demand in the region. Typically the AESO identifies the need for TMR in advance and enters into contracts with suppliers to ensure an adequate and reliable supply for demand in that region. The cost of these contracts is recovered from consumers though ancillary services costs.

In other regions of the province there is typically greater generation capacity in a particular region than local demand, however there may not be sufficient transmission capacity to transfer this supply to other sources of demand. In these regions generation may regularly be constrained from the market resulting in higher pool prices, and thus higher costs for all consumers. This is known as constrained down generation.

**EXISTING TRANSMISSION CONSTRAINTS**

The diagram below illustrates the impact of constraints on the system. The original price at 9,500 MW dispatch level is $73.35/MWh. When a 100 MW constraint is applied, the price increases to $494.70/MWh, resulting in a difference of $421.35/MWh. This highlights the significant economic impact of transmission constraints on energy markets.

![Figure 1: Illustrative example of the impact of constraints on the system](image-url)
Transmission must-run (TMR)

The amount of TMR varies depending on system conditions, regional loads, and the underlying cost of power. The vast majority of TMR used in the province is in the Northwest region of the province, particularly in the Rainbow region. Additional TMR may be required in the Calgary area depending on the system conditions.

Table 2 provides a summary of the amount of TMR required, and the annual costs of that TMR. Even though there is a significant amount of TMR required the cost to load is little as the contracts are to support specific generators and not all supply.

<table>
<thead>
<tr>
<th>Year</th>
<th>Volume (GWh)</th>
<th>Cost ($ millions)</th>
<th>Total AIES load (GWh)</th>
<th>Cost per MWh of load</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>983</td>
<td>43.4</td>
<td>55,980</td>
<td>0.78</td>
</tr>
<tr>
<td>2009</td>
<td>1,018</td>
<td>26.4</td>
<td>54,584</td>
<td>0.48</td>
</tr>
<tr>
<td>2010</td>
<td>792</td>
<td>26.1</td>
<td>55,302</td>
<td>0.47</td>
</tr>
</tbody>
</table>

Constrained down generation (CDG)

Since 2008 the AESO’s system controllers have recorded the amount of constrained down generation in response to their requirements in the calculation of the amount of dispatch down service (DDS) applicable to the market. This information is recorded manually by the controller and does not always contain precise information as to the amount and location of the constraint, particularly when there are multiple sources of constrained generation.

Typically the main sources of constrained generation are constrained wind generation in the south, constraints to Fort McMurray cogeneration, particularly when there are line outages in the northeast, and constraints in the KEG area in response to transmission upgrades in the most concentrated region of the province for generation.

In 2010, 700 GWh of CDG was recorded by the system controllers. This is a significant increase over both 2008 (295 GWh) and 2009 (55 GWh), and is predominately due to major constraints that occurred during the months of April, May and June 2010. Table 3 indicates the recorded amount of generation constrained over the past three years. The constraints have been categorized as either major or regular. Major constraints include those constraints that would have a significant impact to the market, for example constraints to KEG area generators. Regular constraints represent constraints that occur on a regular basis, for example constraints to wind generation and Fort McMurray area generation.

<table>
<thead>
<tr>
<th>Year</th>
<th>Total CDG</th>
<th>Major constraints</th>
<th>Total regular constraints</th>
<th>Wind</th>
<th>Fort McMurray</th>
<th>Wind and Fort McMurray</th>
<th>Others</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>295</td>
<td>274</td>
<td>21</td>
<td>20</td>
<td>1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>2009</td>
<td>55</td>
<td>16</td>
<td>39</td>
<td>27</td>
<td>8</td>
<td>3</td>
<td>1</td>
</tr>
<tr>
<td>2010</td>
<td>700</td>
<td>591</td>
<td>109</td>
<td>57</td>
<td>23</td>
<td>16</td>
<td>14</td>
</tr>
</tbody>
</table>
Overall, there appears to have been an increase in the magnitude of constraints over all types of constraints. Table 4 indicates that the frequency of constraints appears to have increased as well.

Table 4: Number of hours with constrained down generation entered by the system controller

<table>
<thead>
<tr>
<th>Year</th>
<th>Total CDG</th>
<th>Major constraints</th>
<th>Total regular constraints</th>
<th>Wind</th>
<th>Fort McMurray</th>
<th>Wind and Fort McMurray</th>
<th>Others</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>1,516</td>
<td>1,009</td>
<td>507</td>
<td>481</td>
<td>25</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>2009</td>
<td>1,202</td>
<td>151</td>
<td>1,051</td>
<td>806</td>
<td>127</td>
<td>86</td>
<td>32</td>
</tr>
<tr>
<td>2010</td>
<td>3,295</td>
<td>1,651</td>
<td>1,644</td>
<td>1,078</td>
<td>321</td>
<td>121</td>
<td>124</td>
</tr>
</tbody>
</table>

On a monthly basis, there appears to be an increasing trend in regular constraints as seen in Figure 2. Along with increasing in magnitude, the diversity and regularity of constraints has increased with more regular constraints occurring in the Fort McMurray region and other regions over the past 18 months.

Figure 2: Monthly amounts of regular sources of constrained generation

The figures above classify constraints into either major or regular constraint types. Major constraints reflect those that occur on either a planned or unplanned basis, and have a significant impact on the market, either due to duration or magnitude of the constraint. Planned maintenance in the KEG area has resulted in significant constraints to generation in the past and are further described on the next page. In addition, unplanned transmission outages due to a spring storm in southeast Alberta resulted in significant constraints in 2010, also described on the next page.
**KEG upgrade in 2008**

A significant amount of supply was unavailable to the market in April and May 2008 due to transmission maintenance related to the KEG conversion project. The majority of the work on the KEG project occurred in April. In addition, there were planned and unplanned outages at coal-fired plants during the period of the KEG conversion, particularly in April and May.

**Major Constraints in 2010**

In May 2010, a significant amount of supply from coal-fired generation was unavailable to the market due to unplanned transmission maintenance in southeast Alberta and planned maintenance in the KEG area.

On April 14, 2010, a spring storm in southeast Alberta caused several transmission line outages that resulted in significant constraints to the coal-fired generators in the area and curtailment of Alberta Saskatchewan intertie imports to manage the constraint. Repair of the impacted lines was completed in June, 2010. In addition to the southeast constraints, the KEG area underwent several planned transmission outages within the same time period, in particular during the months of May and June. Nearly 75 per cent of the total constraints during the year occurred during this event from April 14th to June 3rd.

Figure 3 below displays monthly major constraints from 2008 to 2010. There is no trend in major constraints, which occur on an ad hoc basis in response to either planned or unplanned events.

**Figure 3: Monthly amounts of generation constrained due to major events**

![Figure 3: Monthly amounts of generation constrained due to major events](image)

The analysis on the pool price impact of these constraints will be performed using this information on historical constraints.
PRICE IMPACT OF CONSTRAINED GENERATION

The AESO dispatches energy in the merit order to meet demand. If supply is constrained due to transmission constraints then the AESO will dispatch up the merit order to meet the demand with unconstrained, higher price generation. This results in an increase in the pool price, the amount of which varies in relation to the dispatch level, the constraint amount, and the structure of the merit order which is determined by offers made by participants.

To analyze the potential impact a constraint would have on price a simulation based on historical merit orders was done. The intention of this simulation was to develop a distribution of price impacts based on varying dispatch levels in the merit order and varying merit orders. The methodology employed was as follows:

- Randomly select a date and time (hour ending) and find the corresponding merit order snapshot.
- Randomly select a dispatch level in the blocks priced above $0/MWh and below the price cap based on the historic distribution of dispatch levels within the merit order. This is done to reflect the historical variation in the dispatch level.
- Determine the price that corresponds with the dispatch level selected. For the purpose of this analysis it is assumed that this price will be effective for the entire hour, hence the prices are considered the pool price.
- Add the amount of constrained generation to the selected dispatch level.
- Determine the new, potentially higher, pool price based on the second dispatch level.
- Calculate the difference in pool price.

Key assumptions of this methodology include:

- All blocks in the merit order are flexible and thus may be partially dispatched.
- All offers above the original dispatch level are unconstrained. If they were constrained then there would be an even larger pool price increase.
- Offer behaviour, including imports and exports, are not significantly impacted by the existence of the constraint on the system.
- By selecting a random merit order and a random dispatch level, there is an implicit assumption that the merit order and the dispatch level are not necessarily dependant. This assumption was made for model simplification. Future improvements may be to produce on and off peak versions of this analysis.

The impact of price responsive load is not modeled as these loads do not bid into the market. It is also assumed that there is no impact by the dispatch down service (DDS) being dispatched on or off.
This analysis is intended to incorporate the unknowns associated with trying to re-price historic events and can be expanded to estimate the cost of other periods of constraints using the distribution illustrated in the Figure 4. Overall, any generation pocket where lower price generation is being constrained will result in higher overall costs for load as higher price generation will be required to balance the system.

To determine a distribution of price impacts across a range of constrained generation amounts and dispatch levels a total of 100,000 samples were taken for levels of 5, 10, ..., 500 MW of constraints for 2008, 2009 and 2010 merit orders. Figure 4 illustrates the pool price impact results for 2010. It is noted that in 2008 the merit order was substantially different than in 2009 and 2010 due to offer behavior changes and very different costs of natural gas.

It is noted that at low levels of constraints there is less chance that there will be a significant price differential, at higher levels of constraints there may be upwards of a 12 per cent chance that the price may increase by over $250/MWh (red and dark red region of the graph below). To read the figure the x-axis is the distribution of price increases given a certain level of constraint, the y-axis is the constraint level, and the colors represent the range of price increases. The right hand chart illustrates the colors associated with differing price increases.

**Figure 4: Price impacts of constraints based on 2010 merit orders**
Choosing a specific level of constraint, say 100 MW, it is possible to see that 50 per cent (inter-quartile range) of the time the price impact would be between $1.11/MWh and $6.12/MWh, 25 per cent of the time the price differential being negligible (less than $1.11/MWh) and the remaining 25 per cent of the time price differentials would exceed $6.12/MWh.

In 6.2 per cent of the cases a 100 MW constraint on the system may see a price increase of over $100/MWh. This would typically happen when there is a significant gap in the prices that generators have offered into the merit order. Using the resulting distribution of the price impact, the expected value (average of the distribution) of the impact of a 100 MW constraint would be $20.60/MWh. It is noted that this distribution is very much skewed, illustrated by the fact that the average impact is greater than 75th percentile (%ile). Figure 5 illustrates the duration curve results for this example.

**Figure 5: Duration curve of price impacts of 100 MW of constraints based on 2010 merit orders**

*Distribution of price differentials based on 100 MW of constraints in the EMMO (2010 results)*

<table>
<thead>
<tr>
<th>Price differential ($/MWh)</th>
<th>Distribution</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>5</td>
<td>20%</td>
</tr>
<tr>
<td>10</td>
<td>40%</td>
</tr>
<tr>
<td>25</td>
<td>60%</td>
</tr>
<tr>
<td>50</td>
<td>80%</td>
</tr>
<tr>
<td>75</td>
<td>100%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Expected value (mean, average)</th>
<th>$20.60/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Median value</td>
<td>$2.63/MWh</td>
</tr>
<tr>
<td>5th %ile</td>
<td>$0.11/MWh</td>
</tr>
<tr>
<td>25th %ile</td>
<td>$1.11/MWh</td>
</tr>
<tr>
<td>75th %ile</td>
<td>$6.12/MWh</td>
</tr>
<tr>
<td>95th %ile</td>
<td>$147.85/MWh</td>
</tr>
</tbody>
</table>

The expected value of the impact of constraints increases as the amount of generation constrained increases. In 2010, on average, a five MW constraint may raise the price approximately $1/MWh, while a 500 MW constraint will see an average increase of nearly $90/MWh. At constraints of 170 MW or greater there is at least a five per cent chance that prices will increase by $250 MW or greater.

As this analysis was performed using three years of merit orders there is noticeable differentiation in the results reflecting differing market conditions over time. The following table, Table 5, provides sample summary statistics on each set of price impact results for a few levels of constrained down generation. The results from 2008 are significantly higher than 2009 and 2010 as the merit order in 2008 was based on higher offer prices, which reflected the higher natural gas price throughout the year, particularly prior to September 2008. The average impact in 2008 is approximately 140 per cent higher than the price impacts observed in 2009 and 2009 (where prices only varied by only one per cent).

Figure 6 illustrates the increasing trend in all the summary statistics for the results based on the 2010 merit orders.
Table 5: Summary statistics for the price impact of constrained generation based on 2008, 2009, and 2010 merit orders

<table>
<thead>
<tr>
<th>Study year</th>
<th>MW constrained</th>
<th>Average</th>
<th>Median</th>
<th>5th percentile</th>
<th>25th percentile</th>
<th>75th percentile</th>
<th>95th percentile</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>5</td>
<td>$2.54</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$4.55</td>
</tr>
<tr>
<td></td>
<td>25</td>
<td>$12.85</td>
<td>$0.22</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$3.81</td>
<td>$50.68</td>
</tr>
<tr>
<td></td>
<td>50</td>
<td>$25.19</td>
<td>$2.69</td>
<td>$0.00</td>
<td>$0.14</td>
<td>$9.50</td>
<td>$168.18</td>
</tr>
<tr>
<td></td>
<td>100</td>
<td>$49.60</td>
<td>$8.00</td>
<td>$2.06</td>
<td>$21.06</td>
<td>$379.87</td>
<td></td>
</tr>
<tr>
<td></td>
<td>250</td>
<td>$117.72</td>
<td>$24.35</td>
<td>$1.61</td>
<td>$11.15</td>
<td>$60.81</td>
<td>$624.88</td>
</tr>
<tr>
<td></td>
<td>500</td>
<td>$217.20</td>
<td>$50.28</td>
<td>$8.55</td>
<td>$30.35</td>
<td>$414.30</td>
<td>$861.78</td>
</tr>
<tr>
<td>2009</td>
<td>5</td>
<td>$1.12</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$1.70</td>
</tr>
<tr>
<td></td>
<td>25</td>
<td>$5.66</td>
<td>$0.15</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$1.46</td>
<td>$13.37</td>
</tr>
<tr>
<td></td>
<td>50</td>
<td>$11.10</td>
<td>$1.09</td>
<td>$0.14</td>
<td>$3.53</td>
<td>$30.70</td>
<td></td>
</tr>
<tr>
<td></td>
<td>100</td>
<td>$21.04</td>
<td>$3.16</td>
<td>$1.12</td>
<td>$7.12</td>
<td>$123.04</td>
<td></td>
</tr>
<tr>
<td></td>
<td>250</td>
<td>$48.86</td>
<td>$9.05</td>
<td>$5.03</td>
<td>$18.19</td>
<td>$394.22</td>
<td></td>
</tr>
<tr>
<td></td>
<td>500</td>
<td>$90.63</td>
<td>$19.26</td>
<td>$6.00</td>
<td>$36.63</td>
<td>$678.04</td>
<td></td>
</tr>
<tr>
<td>2010</td>
<td>5</td>
<td>$1.07</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$0.00</td>
<td>$1.41</td>
</tr>
<tr>
<td></td>
<td>25</td>
<td>$5.35</td>
<td>$0.20</td>
<td>$0.00</td>
<td>$1.20</td>
<td>$15.00</td>
<td></td>
</tr>
<tr>
<td></td>
<td>50</td>
<td>$11.00</td>
<td>$1.05</td>
<td>$0.23</td>
<td>$3.09</td>
<td>$46.10</td>
<td></td>
</tr>
<tr>
<td></td>
<td>100</td>
<td>$20.60</td>
<td>$2.63</td>
<td>$1.11</td>
<td>$6.12</td>
<td>$147.85</td>
<td></td>
</tr>
<tr>
<td></td>
<td>250</td>
<td>$48.84</td>
<td>$7.35</td>
<td>$4.22</td>
<td>$15.30</td>
<td>$369.46</td>
<td></td>
</tr>
<tr>
<td></td>
<td>500</td>
<td>$89.20</td>
<td>$15.41</td>
<td>$5.58</td>
<td>$9.88</td>
<td>$32.04</td>
<td>$606.46</td>
</tr>
</tbody>
</table>
Based on this analysis, a distribution of potential price increases for a given constraint has been developed. This allows an estimation of the total cost of constraints on the system. Of note, while in many hours the price increase is expected to be low, the small proportion of the time that the price increase can be substantial drives the fact that without adequate transmission capacity, when generation is constrained from the market there is a significant risk of increasing prices.
ESTIMATES OF THE TOTAL MARKET IMPACT OF CONSTRAINTS

To estimate the total impact constrained down generation has on the market, further simulation study was performed using the same levels of constrained generation observed in 2008 to 2010.

To estimate the annual market value (a cost to load as higher pool prices occur as result of the constraint), the pool price impact results were used. The following methodology was employed to estimate the market value:

- Round the observed hourly constraint to the nearest 5 MW.
- Randomly select a price impact from the distribution of price impacts for that year and that particular MW level (for constraints greater than 500 MW, the 500 MW distribution was used\(^1\)).
- Multiply the price impact by 6,300 MWh (indicative of the three year average of hourly AIES load).
- Repeat for all hours with constraints in the year.
- Sum to arrive at an annual cost.

This procedure was run 10,000 times for each year to develop a distribution of costs. Furthermore, the costs were allocated to whether the constraint was due to a major system event such as the KEG area 500 kV upgrade in 2008, the constraints resulting from a spring storm in 2010, or regular frequent constraints that occur such as those related to wind generation or the Fort McMurray area. Table 6 presents the results. In the years with major constraints one does see substantial increases in costs as, during these periods, significant amounts of supply were constrained from the market, resulting in higher pool prices and thus higher energy costs.

---

\(^1\) Due to this the volume of CDG analyzed is less than the amount recorded and reported in the earlier discussion.
Table 6: Summary statistics of the estimated cost of transmission constraints

<table>
<thead>
<tr>
<th>Year</th>
<th>Total CDG analyzed (GWh)</th>
<th>Mean</th>
<th>Median</th>
<th>Minimum</th>
<th>5th percentile</th>
<th>25th percentile</th>
<th>75th percentile</th>
<th>95th percentile</th>
<th>Maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>Total</td>
<td>285.8</td>
<td>$827.3</td>
<td>$826.8</td>
<td>$690.7</td>
<td>$756.6</td>
<td>$797.8</td>
<td>$856.4</td>
<td>$998.5</td>
</tr>
<tr>
<td></td>
<td>Major constraints</td>
<td>264.8</td>
<td>$760.7</td>
<td>$761.0</td>
<td>$610.0</td>
<td>$692.2</td>
<td>$731.5</td>
<td>$788.9</td>
<td>$829.5</td>
</tr>
<tr>
<td></td>
<td>Regular constraints</td>
<td>21.0</td>
<td>$66.6</td>
<td>$66.1</td>
<td>$32.7</td>
<td>$50.4</td>
<td>$59.4</td>
<td>$73.4</td>
<td>$84.1</td>
</tr>
<tr>
<td>2009</td>
<td>Total</td>
<td>55.4</td>
<td>$75.5</td>
<td>$75.2</td>
<td>$43.1</td>
<td>$59.7</td>
<td>$68.5</td>
<td>$82.1</td>
<td>$92.3</td>
</tr>
<tr>
<td></td>
<td>Major constraints</td>
<td>16.3</td>
<td>$21.5</td>
<td>$21.1</td>
<td>$0.0</td>
<td>$12.5</td>
<td>$17.3</td>
<td>$25.3</td>
<td>$32.1</td>
</tr>
<tr>
<td></td>
<td>Regular constraints</td>
<td>39.1</td>
<td>$54.0</td>
<td>$53.7</td>
<td>$28.7</td>
<td>$41.4</td>
<td>$48.4</td>
<td>$59.2</td>
<td>$67.6</td>
</tr>
<tr>
<td>2010</td>
<td>Total</td>
<td>577.0</td>
<td>$691.3</td>
<td>$691.1</td>
<td>$552.3</td>
<td>$628.0</td>
<td>$665.3</td>
<td>$716.5</td>
<td>$756.2</td>
</tr>
<tr>
<td></td>
<td>Major constraints</td>
<td>467.7</td>
<td>$547.7</td>
<td>$547.4</td>
<td>$429.0</td>
<td>$489.6</td>
<td>$523.4</td>
<td>$571.6</td>
<td>$607.7</td>
</tr>
<tr>
<td></td>
<td>Regular constraints</td>
<td>109.3</td>
<td>$143.6</td>
<td>$143.2</td>
<td>$98.4</td>
<td>$120.8</td>
<td>$133.7</td>
<td>$153.1</td>
<td>$168.4</td>
</tr>
</tbody>
</table>

It is notable that the trend over the past three years, excluding the costs associated with major constraint events, is increasing levels of constraint and increasing costs.

Of the regular constraints, constraints related to wind and outflows from the Fort McMurray region constituted the majority of the generation constrained from the market. Due to how constraints are recorded some of the periods had multiple constraints on the system, resulting in difficulty classifying the level of constraint due to each issue. Estimates have been made on the cost impact for each of the four regular constraint categories defined in the historical analysis of constrained generation. Table 7 illustrates the results.

Table 7: Average estimated cost of regular constraints by type ($ millions)

<table>
<thead>
<tr>
<th>Year</th>
<th>Total regular constraints</th>
<th>Wind</th>
<th>Fort McMurray</th>
<th>Wind and Fort McMurray</th>
<th>Others</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>$66.6</td>
<td>$64.8</td>
<td>$1.8</td>
<td>$0.0</td>
<td>$0.0</td>
</tr>
<tr>
<td>2009</td>
<td>$54.0</td>
<td>$38.0</td>
<td>$10.5</td>
<td>$4.4</td>
<td>$1.1</td>
</tr>
<tr>
<td>2010</td>
<td>$143.7</td>
<td>$76.4</td>
<td>$30.0</td>
<td>$19.9</td>
<td>$17.4</td>
</tr>
</tbody>
</table>
NEXT STEPS

The AESO will continue to refine and evolve this analysis to gain a better assessment and understanding of the impact transmission constraints have on the market as an aid to identifying the need for transmission system upgrades.

CONCLUSIONS

Based on this analysis there are significant system costs associated with transmission constraints. The impact of constrained generation on pool price varies with the offer curve, demand levels and other market fundamentals. It is estimated that for constraints similar to those observed in the past three years pool prices are, on average, greater by $1.59/MWh for regular constraints, and $8.02/MWh for constraints associated with major events compared to an unconstrained system. In addition, over the past three years the cost of TMR due to location-specific constraints has averaged $0.58/MWh.

These costs, the observed trend of increasing levels of constraint, and the currently forecast increases in demand and generation levels indicate that there is significant value to incremental transmission capacity in Alberta. Alberta's single price energy only market design is predicated on an unconstrained transmission system and this analysis illustrates the market inefficiencies that result from transmission constraints under this market design.