2008 Annual Report

aeso
ALBERTA ELECTRIC SYSTEM OPERATOR

Powering Alberta

Our Vision

The Alberta Electric System Operator is seen as a key contributor to the development of Alberta and the quality of life for Albertans through our leadership role in the facilitation of fair, efficient and openly competitive electricity markets and the reliable operation and development of the Alberta Interconnected Electric System.

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Our Mission

The Alberta Electric System Operator facilitates a fair, efficient and openly competitive market for electricity and provides for the safe, reliable and economic operation of the Alberta Interconnected Electric System.

Our Values

INNOVATION – finding a possibility where one might not be readily apparent or inventing a new approach when we are working on a customer project that has never been done before.

COLLABORATION – drawing on the power of synergy and diversity. Developing win-win ways with customers and stakeholders using the input and ideas from all interested parties to find ways to unleash new potential.

INTEGRITY – sharing a common bond to do the right thing and to do things right.

LEADERSHIP – taking steps within our mandate to make things happen; finding new ways to do things and identifying opportunities to make things better.

QUALITY – assurance that our plans, processes and procedures are accurate, workable and appropriate for their intended purpose.

Core Businesses

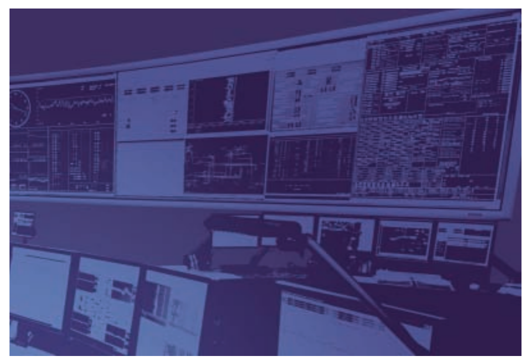
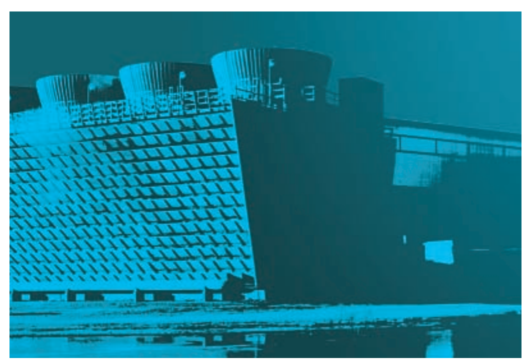
We are responsible for . . .

- **ELECTRIC SYSTEM DEVELOPMENT *(Transmission)*** – assessing the current and future needs of market participants and planning the transmission to meet those needs. We utilize a system planning process that proactively identifies, plans, achieves approvals for and initiates the implementation of system reinforcements ensuring that the resulting plan is cost-effective. Our objective is to ensure transmission facilities are in place to maintain reliable and economic transmission system operation and the facilitation of competitive electricity markets.

- **ELECTRIC SYSTEM INTERCONNECTIONS** – providing customers with transmission system access to the Alberta power grid. Our goal is to deliver a high-quality interconnection service in an efficient and timely manner that meets both the customer's needs and the requirements of the Alberta Interconnected Electric System (AIES).

- **ELECTRIC SYSTEM OPERATIONS** – operating the wholesale electricity market and directing the safe, reliable and economic operation of the AIES. Our objectives are to ensure:
  - The AIES is operated in a reliable way in compliance with all applicable reliability standards.
  - Open access to transmission and markets.
  - The consistent application of rules and requirements.

- **MARKET DEVELOPMENT AND OPERATIONS** – facilitating the development and operation of the competitive wholesale market for electricity, including financial settlement. We ensure that the market operates in a fair, efficient and openly competitive manner that will result in a predictable market structure that adds long-term value.


Message from the Chairman and the CEO

Harry Hobbs
Chairman

David Erickson
President & Chief Executive Officer (Interim)

2008 was a journey of extremes. In less than 12 months we went from a time of hyper-development across Alberta to a sudden and dramatic slowdown. It was not that long ago that the price of oil exceeded $140 per barrel and our province was feeling the strain from years of growth rates that led the nation. We saw stiff competition for new employees, construction equipment and labour, and supplies of the necessary products and services to keep up with unprecedented growth.

It has been a frenetic pace. And perhaps no other infrastructure experiences the strain of this accelerated pace of growth in the same way as electricity – transmission lines are essential to carry the power that supports every aspect of our lives, businesses and industry. Safe and reliable electricity underpins Alberta's economic progress, our livelihood and our well-being. The transmission system is a public good.

It is not enough for electricity infrastructure to match growth. Transmission lines must be in place ahead of the time they are needed to lead power generation development and to facilitate investment in Alberta's economic growth and prosperity. The regulatory process and construction of transmission infrastructure can take 10 years or more before new facilities are in place to transport essential electricity from where it is produced to where it is needed in our province. Adequate electric transmission must be in place in a timely manner as a signal that Alberta is well-positioned to continue to attract investors to our province.

Over the last several years Alberta has experienced growth in electricity demand that is equivalent to adding two cities the size of Red Deer to the power grid every year. While some new regional transmission facilities have been added to the system over the period, no major upgrades to the critical backbone of the grid have been built in over 20 years. Portions of the province's essential electricity highway are aging, congested and inefficient. Although the current economic slowdown has provided a pause in the rapid pace of growth and the existing transmission system is able to meet today's needs, it will not be able to meet the future needs of Albertans. Critical new transmission must be built at the earliest opportunity to meet the expected demand as our province recovers from the slowdown.

While the Alberta Electric System Operator (AESO) has approximately $3.2 billion in transmission system reinforcements currently underway (including projects approved, pending approval and under construction) throughout the province, additional critical transmission infrastructure is required. Strengthening the backbone of the interconnected system between Edmonton and Calgary, in southern Alberta, and between the Edmonton area and the northwestern and northeastern parts of the province cannot wait – projects must move forward today to meet the needs of tomorrow. This requires a long-term view in keeping with responsible stewardship of essential infrastructure assets that will operate for 30 to 40 years into the future.

Alberta Provincial Energy Strategy – December 2008

Electricity is at the heart of Alberta's new Provincial Energy Strategy. "Transmission infrastructure is a public good that must be available in advance of need, enable addition of new generation and be capable of meeting long-term load growth throughout the province."

(Launching Alberta's Energy Future, Provincial Energy Strategy, page 43)

In late 2008, the Government of Alberta published the Provincial Energy Strategy, a document that sets out an integrated vision for the development of Alberta's energy resources. This strategy has three explicit outcomes:

- clean energy production
- wise energy use
- sustained economic prosperity

The Strategy also recognizes electricity as a facilitator of continued prosperity in Alberta. The AESO will file a Long-term Transmission System Plan with the Alberta Utilities Commission (AUC), which will be aligned with the Provincial Energy Strategy.

The approach to build transmission in advance of new generation and investment as outlined in the Provincial Energy Strategy recognizes the current economic situation. Today, the materials, labour and equipment necessary to build transmission facilities are more readily available than in the past and potentially at lower cost. There is a window of opportunity to move with dispatch to access labour, towers, related equipment and other resources that are necessary to build electric transmission systems before other jurisdictions that are competing for the same resources.

Energizing Alberta's future economic development is the top priority at the AESO. In addition to our focus on strengthening transmission infrastructure, the organization's other key priorities – ensuring reliable market and system operations and delivering excellent service to our customers – are also linked to enabling economic progress and the overall well-being of Albertans.

By leveraging its technological expertise and proven track record of operational excellence, the AESO, together with industry partners, will implement a Long-term Transmission System Plan that will enable reliable and efficient operation of Alberta's electricity markets and power grid well into the future. Technology is one of the AESO's proven areas of expertise. The organization is providing industry leadership in developing the tools, technology and skills required to integrate significant amounts of new wind power and other renewable energy options.

The company's System Control Centre is the heart of its 24/7 operation and facilitates its mandate to keep the competitive market functioning and the lights on in Alberta. Operating a strained, aging and congested transmission system becomes more challenging every year. Through technology and operating initiatives, the AESO is able to maintain the system and meet the current needs of Albertans. The AESO successfully combines sophisticated technology and top-notch talent to continue to deliver reliable electricity to homes, schools, hospitals and industry.

During 2008, we advanced a number of key market development initiatives. We met some aggressive timelines to develop, consult and file market rules on long-term adequacy, congestion management, reliability unit commitment and generator outage coordination. We also received a strong endorsement from stakeholders for creating the Market Advisory Committee to effectively address the ongoing evolution of the market. Our operating reserves market redesign process and consultation also received positive feedback from stakeholders.

Another corporate priority – a focus on delivering excellence in customer service – provides investors with access to reliable electricity for their business or industry, and connects power generators to the grid so they can sell their electricity in Alberta and beyond.

The AESO's customer service team is dedicated to providing high-quality products and services in a timely manner. A customer's needs, whether they are related to the technical, market, financial or contractual aspect of their interconnection or participation in the energy market, will be addressed with a comprehensive and integrated approach.

During 2008, we commenced a multi-year, strategic customer service initiative that resulted in some organizational changes to create a more integrated approach to serving customers and to improve delivery of our products and services. According to the results of our 2008 customer satisfaction survey, the changes we are implementing are making a difference. In our 2008 customer survey, 87 per cent of respondents indicated they saw improvements in our customer service during the year.

Business and industry depend on timely interconnection services and access to reliable electricity to bring their products and services to market, which facilitates economic development. Competitive generation developers rely on transmission system interconnections to sell power to Albertans and surplus electricity to interconnected markets in North America. And we all rely on electricity to be there when we flip the switch.

Looking back on the last year, we are proud of the great strides achieved by the AESO to take a more active role in communicating with the public and we thank all our stakeholders for their participation, involvement and contribution to various committees and initiatives.

During 2007 and 2008, over 2,000 landowners, stakeholders and members of the general public participated in approximately 300 open houses and group meetings as part of the transmission system development consultation process. The AESO used a variety of methods to notify, consult and engage stakeholders including mailings, newspaper and radio ads, news releases, website postings, meetings and presentations, correspondence (email and mail), phone, industry sessions and open houses. Over 2.1 million letters, open house invitations and project backgrounders were prepared as an expression of our engagement activities.

The second edition of *Powering Albertans* magazine was produced and distributed – with 1.2 million copies mailed to homes in Alberta and numerous copies sent to schools, libraries, chambers of commerce and town councils.

In the coming year, you will see additional evidence of how the AESO is focusing its efforts to deliver on these three key priorities – implementing much-needed transmission system reinforcements, maintaining and improving market and system reliability and delivering excellence in customer service.

The end result is a fair, efficient and openly competitive electricity market and a safe, reliable and economic power grid that continues to facilitate economic development and the well-being of all Albertans.

In closing, we would like to extend thanks to the team of the AESO Board, management and all employees who continue to dedicate their expertise to achieve the goals of the organization in the interests of all Albertans.

Harry Hobbs
Chairman

David Erickson
President & Chief Executive Officer (Interim)

April 2009

Year in Review

Leadership, integrity, quality, innovation, collaboration – these are the values that guide our work to meet the power needs of Albertans.

Our *Year in Review* section is a look back over the last 12 months to provide information about our key accomplishments and the significant initiatives we have undertaken in 2008. The following pages summarize our efforts to fulfil our mandate and achieve strategic and operational objectives in each of our core business areas. Additional detail is included in the sections that follow. Our business plan is available on our website at **www.aeso.ca**

2008 Strategic Objectives

ELECTRIC SYSTEM DEVELOPMENT *(Transmission)*

Strategic objective:

To build appropriate transmission capacity in a timely manner to meet the forecast needs of Alberta, facilitate competitive markets and meet the challenges of provincial economic aspirations, extreme weather, expanding markets and disaster avoidance.

INFORMATION TECHNOLOGY

Strategic objective:

Establish a technology roadmap for aging market and operations systems.

ELECTRIC SYSTEM OPERATIONS

Strategic objective:

Ensure that the Alberta Interconnected Electric System (AIES) is operated in a safe, reliable and economic manner.

PUBLIC EDUCATION AND OUTREACH

Strategic objective:

Be viewed by stakeholders as a leader and facilitator of Alberta's competitive electricity market and the reliable operation and development of the AIES, and preserve, protect and enhance the AESO's reputation.

MARKET DEVELOPMENT AND OPERATIONS

Strategic objective:

Stabilize the market and regulatory frameworks to enhance confidence of investors and market participants.

2008 Key Achievements Summary

ELECTRIC SYSTEM DEVELOPMENT ***(Transmission)***	
Initiatives	**2008 Achievements**
Edmonton to Calgary reinforcement.	■ Consultation on the Edmonton to Calgary reinforcement involved over 1,200 stakeholders through 40 open houses and a series of meetings. Technical work on the need for the reinforcement was advanced during the year.
System backbone reinforcement.	■ Significant reconfiguration work associated with the Keephills 3 interconnection was developed and the Needs Identification Document (NID) was filed and approved by the Alberta Utilities Commission (AUC). No objections were submitted. ■ A 240 kilovolt (kV) reconfiguration, including the rebuild of a major 240 kV line in the Edmonton area, was advanced in 2008. No objections were submitted.
Regional system reinforcements.	■ A NID was filed for southern Alberta to accommodate up to 4,000 megawatts (MW) of wind power in a flexible and staged approach. ■ A NID was approved with no objections or hearing for 240 kV system upgrades in southeastern Alberta. ■ Completion of a NID for the Heartland area transmission reinforcement. ■ A total of 27 NIDs were filed in 2008.
Long-term Transmission System Plan.	■ Consultation on and development of the Long-term Transmission System Plan was completed to meet a year-end 2008 filing date. Issuance of the Plan was postponed for additional review with the AESO Board in view f the December 2008 Provincial Energy Strategy.

INFORMATION TECHNOLOGY ***(IT)***	
Initiatives	**2008 Achievements**
Replace the aging Energy Management System (EMS) and improve performance of other priority systems.	■ The EMS replacement project is 50 per cent complete and on target for delivery in late 2009. ■ Significant progress made in stabilizing performance of some aging technology tools and systems in 2008.
Develop an integrated vision for IT requirements.	■ Integrated technology roadmap developed to identify high priority initiatives and establish interdependencies and implementation timeframes. ■ Developed a consultation process to create a new integrated strategic vision for the IT systems required for market operations.

ELECTRIC SYSTEM OPERATIONS	
Initiatives	**2008 Achievements**
Effectively operate the system within tight electric system conditions.	▪ Implemented a pilot for dynamic thermal line ratings on a key transmission line to address overload conditions while facilitating capacity increases under certain operating conditions. The project partially addresses wind stakeholders' request for interim solutions until transmission can be built.
Operational efficiency and excellence.	▪ Implemented an advanced approach for voltage stability analysis to allow operation closer to limits. The approach was recognized by the North American Electric Reliability Corporation (NERC). ▪ Developed and implemented IT tools to allow real-time reliability assessments. ▪ Two comprehensive seasonal reliability assessments were prepared for internal use and consultation was completed on a public seasonal reliability report. ▪ Achieved very positive comments in 2008 NERC Readiness Evaluation.
System restoration preparedness.	▪ Completed two industry-wide AIES restoration drills in the fall of 2008. ▪ Implemented a new system restoration training simulator.
Wind integration initiative staged over a number of years.	▪ In consultation with industry, continued development of the framework for creating market rules, interconnection standards, operating protocols, cost recovery and the advancement of appropriate transmission development for integrating wind power. ▪ Developed a comprehensive Wind Integration Recommendation Discussion Paper for release in early 2009. ▪ Completed an industry-leading wind power forecasting pilot, which resulted in numerous recommendations included in the discussion paper noted above. ▪ Implemented a new interconnection queue business practice for wind power developers. ▪ Developed an operating tool prototype to assist with the integration of wind power. ▪ Received recognition for industry leadership and technical excellence from both the international Utility Wind Integration Group and the Canadian Wind Energy Association.

PUBLIC EDUCATION AND OUTREACH	
Initiatives	**2008 Achievements**
Develop and deliver broad-based initiatives including publications, regional advisory program, engagement with stakeholders and government to increase awareness of the AESO, the Alberta electricity infrastructure gap and the industry.	▪ An educational video program was produced and aired on ACCESS TV. The program is also available on DVD. ▪ The second edition of *Powering Albertans* magazine was distributed to approximately 1.2 million Albertans and more than 1,200 copies were sent to teachers throughout the province. ▪ The magazine and DVD have been distributed to over 120 schools and libraries. ▪ The public consultation process was refined and improved continuously throughout the year. More than 2,000 stakeholders and members of the public attended open houses for various transmission projects. Feedback was widely positive for the process and approach. ▪ Six regional advisors were recruited.

MARKET DEVELOPMENT AND OPERATIONS

Initiatives	2008 Achievements
Market Roadmap and *Transmission Regulation* Implementation: ▪ Advance amendments and implement required changes in a timely, collaborative and transparent manner that balances the rights and obligations of all market participants. ▪ Complete implementation of changes arising from the revised *Transmission Regulation*.	▪ Concluded development and implementation of market performance metrics. ▪ Completed implementation of numerous rule changes associated with the government's Electricity Policy Framework. ▪ Conducted extensive consultation on operating reserves market redesign and released a final recommendation paper in January 2009. Received numerous positive comments from stakeholders on the process. ▪ Congestion management rules filed; additional work is underway on Operating Policies and Procedures (OPPs) and implementation. ▪ Generator outage coordination: completed stakeholder consultation process and filed new rules. ▪ Reliability unit commitment: stakeholder consultation process completed and new rules filed. ▪ Participated in Department of Energy consultation on Section 6 (market power mitigation) and engaged the Market Advisory Committee (MAC) for additional input.
Intertie: Implement market rules, OPPs, and systems to facilitate dispatchable imports and exports.	▪ Continued work with the British Columbia Transmission Corporation and Saskatchewan Power Corporation regarding business process changes and technical requirements needed to implement dispatchable interties. A discussion paper and consultation is expected in early 2009.
Mandatory reliability standards framework.	▪ Established the Alberta Reliability Committee and filed two sets of standards with the AUC for approval without intervention.
General Tariff Application (GTA).	▪ 2007 General Tariff Application approved by AUC and implemented.
Additional initiatives and achievements.	▪ Strong endorsement from stakeholders about the MAC process and role to advance market evolution. ▪ Long-term adequacy rules completed and approved without objection.

Electric System Development
(Transmission)

Photo courtesy of AltaLink.

We are responsible for assessing the current and future needs of market participants and planning the transmission to meet those needs. We utilize a system planning process that proactively identifies, plans, achieves approvals for and initiates the implementation of system reinforcements ensuring that the resulting plan is cost-effective. Our objective is to ensure transmission facilities are in place to maintain reliable and economic transmission system operation and the facilitation of competitive electricity markets.

We are responsible for providing customers with transmission system access to the Alberta power grid. Our goal is to deliver a high-quality interconnection service in an efficient and timely manner that meets both the customer's needs and the requirements of the Alberta Interconnected Electric System (AIES).

Key projects advanced in 2008

During 2008, we made significant progress on a number of key initiatives to strengthen Alberta's transmission system. These developments will help ensure the system continues to deliver reliable electricity and interconnect new load and generation customers. Together with the transmission facility owners (TFOs), we completed work required to energize two projects during the year.

- One project included the installation of two new 500 kilovolt (kV) transformers at the Keephills and Ellerslie substations, and the conversion of a substation at Genesee as well as the conversion of two transmission lines from 240 kV to 500 kV. This reinforcement (also known as the Keephills-Ellerslie-Genesee (KEG) conversion) provides additional transmission capacity to allow new generating supply access to the grid. It also reduces system congestion in the area and facilitates needed transmission development between Edmonton and Calgary.
- Another project that came online in October 2008 involved construction of about 10 kilometres (km) of 240 kV underground transmission in the City of Edmonton. These facilities were required to provide additional supply capacity into downtown Edmonton and to ensure continued reliable power service to the city centre.

Northwest transmission development on schedule

Together with the TFO, we are on schedule to complete about $500 million (2008 dollars) in transmission reinforcement that includes more than 700 km of new 138/240 kV transmission lines. New transmission lines from Brintnell to Wesley Creek and Wesley Creek to Hotchkiss are on target for a 2010 in-service date. The Ring Creek to Rainbow Lake and High Level to Sulphur Point lines are scheduled for a 2011 in-service date.

Approved expansion to improve system operations

In June 2008, we received Alberta Utilities Commission (AUC) approval for our Needs Identification Document (NID) to interconnect the Keephills Unit 3 generator. Through this NID we identified the opportunity to modify existing transmission facilities to interconnect the generating unit. This included expanding the existing Keephills 500 kV substation and energizing the existing transmission line between Keephills and Ellerslie to its designed voltage of 500 kV. Additional transmission equipment needed for this interconnection is expected to further improve overall system operations. The target in-service date for the interconnection is February 2010.

Catching up to growth

The demand for electricity has increased 29 per cent since 2000, but in the last 20 years only one major transmission line has been built from the Fort McMurray area to the Edmonton area. Some smaller regional facilities have also been installed during the timeframe.

Our studies show the long-term demand for electricity will continue to grow. We view the current economic situation as an opportunity to invest in needed infrastructure at a time when Alberta will likely experience lower costs for electrical equipment, construction resources and labour. Moving forward with our plans now will allow transmission reinforcements to catch up to recent growth, accommodate future growth, improve system efficiency and capability, and meet legislated requirements to restore the capacity of our interties with neighbouring jurisdictions.

Long-term outlook for electricity demand

Our long-term studies indicate that peak demand growth will average 3.4 per cent over the next 20 years. This is equivalent to adding two cities the size of Red Deer (a population of about 88,000) every year.

Our Alberta Internal Load (AIL) 2008 forecast shows an annual average growth rate of 3.4 per cent for demand and a 3.3 per cent growth rate for energy during the 2008 to 2028 timeframe. AIL is the total electricity consumption including behind-the-fence load, the City of Medicine Hat (which has its own generation supply) and transmission and distribution losses.

AIL electricity consumption during the 20-year period is forecast to increase 92 per cent, rising from 73,062 gigawatt hours (GWh) forecast for 2009 to 140,265 GWh in 2028.

Our generation scenario analysis identifies a doubling of today's generating capacity by 2027. It is anticipated that 5,000 megawatts (MW) of generation will be needed by 2017 and a total of 11,500 MW by 2027 to meet the growth in demand and compensate for the retirement of existing generating units and equipment.

We continue to monitor and assess the impact of the global economic downturn on electricity demand and supply, while developing reasonable and prudent transmission plans that are flexible and can be implemented in stages to meet changes in load, industrial activity, and the timing and location of new generation. The AESO's Future Demand and Energy Outlook is available on the website at **www.aeso.ca**

Long-term Transmission System Plan developed

During 2008, we continued consultation and development of the Long-term Transmission System Plan to meet a filing date with the AUC of year-end 2008. However, the filing date was postponed to review the Plan in light of the Provincial Energy Strategy released in December 2008.

The Long-term Plan will set a blueprint for Alberta's critical transmission infrastructure. We are following a comprehensive approach to make sure the electric transmission system is strengthened so all Albertans can continue to depend on safe, reliable electricity. At the same time, the Plan is intended to provide confidence for industry investors and all power generators, including those who want to build more green power using the wind, sun and water for Alberta's competitive market. The Plan will ensure that essential transmission lines will be in place to meet Albertans' electricity needs for decades to come.

New transmission lines will be sized to accommodate long-term growth and will use technology to maximize efficiency and minimize environmental impacts. A strong transmission system in place ahead of investor decisions benefits all Alberta consumers by energizing our economy.

Our Long-term Plan will focus on key reinforcements to help the transmission system:

- Maintain system reliability.
- Catch up to growth averaging three per cent annually over the last 10-year period.
- Enable renewables and low-emission generation.
- Provide certainty to new power developers and power consumers.
- Increase intertie capability.
- Increase efficiency, reducing costly and wasteful transmission system losses.
- Facilitate the fair, efficient and openly competitive wholesale electricity market and enable Alberta's economic development through a robust and unconstrained transmission system.

Photo courtesy of EPCOR Utilities Inc.

EPCOR's 4.8 MW Clover Bar landfill gas facility in Edmonton is the first of its kind in Alberta to both recover methane and use it to generate electricity.

Edmonton to Calgary critical transmission reinforcement updated

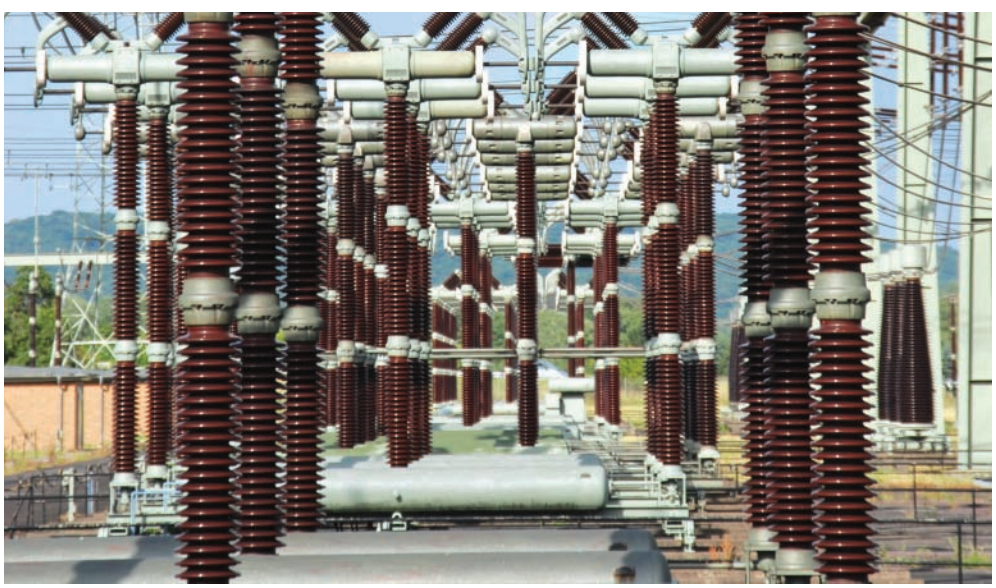
In 2008, we reviewed and updated our existing analysis for the major transmission system reinforcement between Edmonton and Calgary and completed an extensive public involvement program. This included 40 open houses and numerous meetings throughout the region. We gathered input on 11 high-level geographical options and technological alternatives. Information about the technical options, consultation and the geographic areas studied is on our website at **www.aeso.ca**

The Edmonton to Calgary reinforcement will provide the needed transmission infrastructure required to:

- Address reliability issues.
- Accommodate long-term growth.
- Lead generation development decisions.
- Maximize efficiency and minimize impacts.
- Enable development of additional capability on the B.C. intertie.
- Interconnect new renewable and low-emission energy (e.g., a biomass or large hydroelectric facility in northern Alberta).
- Provide capability for wind power located in southern Alberta to reach customers located in other regions.
- Strengthen a key piece of infrastructure (system backbone) so new intertie development can occur.

The reinforcement will resolve reliability issues, increase efficiency and facilitate competition in the power market. Alberta benefits by increasing access for existing generators, enabling investment in new generation and restoring intertie capacity.

Until this critical reinforcement is built, we are taking the necessary proactive steps to ensure the ongoing reliability of the system. This work included a dynamic stability study for the South of Keephills-Ellerslie-Genesee (KEG) power transfers, which confirmed that our existing operating limits and procedures remain sufficient to cover potential contingencies until the transmission reinforcements are built and in service. The KEG conversion that was energized in 2008 (noted on page 11) has also addressed equipment limitations and improved transmission capability in the area.



Stock photograph.

The ongoing provision of competitively priced and reliable electricity enables Alberta's economic progress.

A combination of system improvements and a lower rate of load growth has delayed reliability concerns until 2014. However, a strong and rapid improvement in economic conditions in Alberta could result in system reliability concerns occurring before 2014.

Industrial Heartland reinforcement needed (portions of Sturgeon, Strathcona and Lamont Counties)

The power requirements to extract and upgrade bitumen in the oilsands industry are expected to continue to grow and drive the need for new electricity infrastructure development in the northeastern part of Alberta. Although current oil prices have decreased from their record levels, world oil supplies continue to diminish and investment in the oilsands industry is expected to be strong over the long term.

We continue to evaluate the following options to strengthen the system and meet the required needs:

- A new 500 kV double circuit line from an existing substation in south Edmonton (Ellerslie) to a new substation in the Industrial Heartland area.
- A new 500 kV double circuit line connecting into an existing line on the west side of Edmonton to a new substation in the Industrial Heartland area.

Further analysis will be completed to determine which option will be recommended for implementation. The total estimated capital cost of the project is $387 million (in 2008 dollars), depending on which option is selected. All facilities are expected to be in service by 2015.

Fort McMurray transmission reinforcement options studied

The oilsands industry is expected to continue its growth and is the primary driver of the need for new electricity infrastructure development in the northeastern part of Alberta. The options for reinforcement to meet needs in this area are a 500 kV alternating current (AC) line from west of Edmonton to a new 500 kV substation in the Fort McMurray area, and a 500 kV AC line from a new Heartland substation to the new Fort McMurray 500 kV substation.

Southern Alberta transmission NID filed

In December 2008, we submitted our NID to the AUC to reinforce the transmission system in southern Alberta. The NID is published on our website. Our studies and public involvement program led us to a preferred option for a 240 kV system expansion that would create a transmission line loop into existing 240 kV substations. This option will provide a high level of reliability and interconnect 1,700 MW of wind generation forecast to be operating in southern Alberta within the next 10 years. The current cost estimate for this development is approximately $750 million and the target in-service dates are 2011 to 2012. Subsequent stages of transmission development will proceed when specific criteria are met as outlined in the NID. The total estimated cost of all stages would be $2.4 billion (in 2008 dollars). All transmission facilities would be in service by 2017. The studies for this NID also provided an opportunity to incorporate previously planned upgrades to the Medicine Hat area, which will reduce costs while continuing to meet needs in southern Alberta.

City of Calgary transmission reinforcement required

The transmission system serving the City of Calgary is in need of improvements to address:

- Aging transmission system facilities and significant growth throughout the city.
- Proposed new generation projects (about 1,800 MW) in and near the city.
- The potential for wind power to supply the region when transmission reinforcements are completed in southern Alberta.

We are examining options to reinforce the transmission system in southern Calgary to provide additional support for the area. Further analysis and stakeholder consultation is planned. These reinforcements may include an additional substation and/or new 138 kV lines. One option would be a new 240/138 kV substation near the intersection of Macleod Trail and Highway 22X and associated 240 kV and 138 kV lines to interconnect into the existing system. The total estimated capital cost of the project is $100 million (in 2008 dollars), depending on which option is selected. Construction is planned to begin in 2011 with all facilities in service by 2012.

Comprehensive public involvement initiated throughout the province

All of our transmission reinforcement initiatives include a participant involvement program to share information, gather feedback and address questions the public may have about transmission development. The specific scope, approach and consultation methods used for each project differ depending on the needs of the stakeholders involved and the type of transmission reinforcement being planned.

Over 2,000 landowners, stakeholders and members of the general public participated in approximately 300 open houses and group meetings as part of the transmission system development consultation process during 2007 and 2008.

Stakeholders were identified as:

- residents, occupants, landowners and businesses
- elected and administrative government officials at local, municipal and provincial levels
- industry and industry associations
- First Nations and Métis with interests in the project
- advocacy and environmental groups

The AESO used a variety of methods to notify, consult and engage stakeholders of these groups including:

- mailings
- newspaper and radio ads
- news releases
- website postings
- meetings and presentations
- correspondence (email and mail)
- telephone
- industry sessions
- open houses

2007 – 2008 AESO consultation statistics

	2007	2008
Open houses	21	71
Registered attendees at open houses	480	2,111
Powering Albertans magazine distributed (by edition)	**2007 Summer edition:** ■ Mailed to 550,000 households in Edmonton, central and NE Alberta ■ Mailed/distributed to 76 organizations throughout the province including: libraries, chambers of commerce and town councils	**2008 Spring edition:** ■ 1.2 million copies mailed to all homes in Alberta ■ Additional copies distributed at all open houses (approximately 2,000 copies) ■ Mailed/distributed to over 150 organizations throughout the province including libraries, chambers of commerce and town councils ■ Teachers across Alberta requested 1,200 copies
AESO DVDs distributed	N/A	■ Distributed at 12 open houses ■ Over 120 copies distributed to schools and libraries across the province
Small group meetings	Attended/completed 12 small group meetings	Attended/completed 36+ small group meetings/ events throughout the province
Presentations and discussions with municipalities	64 presentations	84 presentations
Letters, open house invitations and project backgrounders	A total of 2.1 million distributed during 2007 and 2008	

Based on feedback received, there is a general recognition that Albertans' growing demand for additional power must be addressed. Many stakeholders supported the AESO's conclusion that transmission reinforcement is necessary.

A commonly-held stakeholder view was that they prefer reinforcements with higher capacity to accommodate long-term growth that also mitigates the need for repeatedly returning to build more transmission lines in the future. Stakeholders said if they must have towers on their land, they would rather have fewer, larger towers than many smaller towers with lower capacity and have additional development at a future time.

Public involvement principles

The AESO's principles for public involvement in transmission system planning include the following:

- All stakeholders have the right to comment on the AESO's plans, decisions and actions.
- All stakeholders have the right to be informed of the AESO's direction, plans, the status of issues, and decisions in a timely manner.
- The AESO uses the experience and expertise of stakeholders to improve the quality and implementation of decisions.
- The AESO's consultation process and the rationale for the AESO's decisions are transparent.

The principles are available on the website at **www.aeso.ca**

Customer service improvements ongoing

During 2008, we developed a new customer service team and made improvements to processes. We launched a thorough review of our business practices to ensure customer needs are met and quality service is delivered through processes related to transmission interconnections and energy market business interactions.

We also developed additional practices for our contract management process to serve customers more efficiently, and implemented a new method for recalculating customer contributions intended to address concerns raised by some customers.

Ongoing dialogue about interconnection project milestones resulted in a new process that enhances our interconnection queue management and improved practices that are applied to allocate transmission capacity until transmission reinforcements are in place. Our revised practices provide additional clarity about roles and responsibilities, which has led to greater efficiencies. To address a request from customers we developed a combined interconnection queue and a load-only queue, which is published on our website. The existing generation queue is also available on the website. We continue to work on process enhancements and will incorporate customer comments gathered during interviews in 2008 into our plan for ongoing improvements.

Continuing focus on additional intertie capacity

With only two transmission interties with neighbouring jurisdictions providing limited import and export capacity, the AIES is one of the least interconnected jurisdictions in Canada.

Our plan to bring the Alberta-Saskatchewan intertie up to its full design rating was included as part of the AESO's Southeast Alberta Transmission Development NID. This was applied for in November 2007 and subsequently approved in July 2008. The reinforcements are planned to be in service by 2011.

The B.C. intertie is currently operating below its full design capability for exports. The export capacity of the B.C. intertie cannot be significantly restored until the Edmonton to Calgary transmission system is reinforced. Our plan to bring the Alberta-B.C. intertie up to its full design rating is included as part of the required reinforcement of the Edmonton to Calgary transmission system.

The Provincial Energy Strategy reinforces direction provided by the *Transmission Regulation* to increase the capability of the transmission lines that connect our province with its neighbours.

Merchant interties in Alberta

In addition, we work with companies that are proposing merchant transmission lines to connect Alberta to external jurisdictions. A merchant intertie's cost and associated risk is assumed by a non-regulated company. Parties using the intertie would pay a user fee to the owner of the merchant transmission line. Our role is to ensure these proposed projects are reliably connected with Alberta's existing transmission system, and to determine if merchant projects can be used to meet intra-Alberta transmission needs. Developers of merchant intertie projects look to recover their costs from companies that will make use of the line to transport power into or out of Alberta.

Montana Alberta Tie Ltd. (MATL) is proposing to construct a merchant intertie between Lethbridge, Alberta and Great Falls, Montana. The intertie would be constructed at 230 kV and transfer up to 300 MW in each direction. MATL currently has a permit from the National Energy Board and approval from the AUC. Approvals from the necessary agencies in the U.S. are also in hand.

The NorthernLights bi-directional merchant intertie project being planned by TransCanada Corporation is a ±500 kV, 3,000 MW high voltage direct current (HVDC) transmission line from the Industrial Heartland area of Alberta to the U.S. Pacific Northwest. The transmission line would be 1,550 km long and has a tentative in-service date of 2015.

Photo courtesy of AltaLink.

A-frame structures at the Langdon substation east of Calgary.

The Provincial Energy Strategy & the AESO

Advancing Alberta's energy strategy

On December 11, 2008, the Alberta government released its Provincial Energy Strategy, which noted the importance of electricity as a facilitator of economic development in Alberta. "Advancing new transmission investment will ensure reliable service for Albertans, help drive our clean energy agenda by growing new renewable energy potential, and enhance our ability to serve electricity export markets." [1]

The Provincial Energy Strategy goes on to point out that an uncongested transmission system with sufficient intertie capacity to other jurisdictions is required to encourage the development of new electricity generation. By ensuring development of a robust transmission system, generation developers will know that they will be able to efficiently move their product to market. In turn, they will have confidence to develop new generation ensuring an adequate, reliable supply of electricity for Albertans.

The Provincial Energy Strategy identifies the following specific transmission development objectives which the AESO is working towards implementing in our Long-term Plan:[2]

- *Development of a plan that provides a comprehensive upgrade to the transmission system to relieve congestion and reduce significant losses, and the consequential environmental impact, associated with the existing transmission infrastructure.*
- *Sizing of new transmission system facilities to accommodate long-term growth.*
- *Use of high-voltage direct current technology where possible to maximize efficiency of rights-of-way and minimize impacts.*
- *Development of transmission to areas of renewable (e.g., hydro, biomass and wind) and low-emission energy within Alberta.*
- *Development of additional interties to other markets to ensure access to adequate electricity supply and to provide greater export opportunities for producers.*
- *Development of transmission facilities in advance of need to encourage development of new generation and facilitate continued economic growth.*

[1,2] *Launching Alberta's Energy Future, Provincial Energy Strategy, p 44.*

Educational Partnerships

During 2008, we developed and strengthened partnerships with educational institutions in Alberta to promote power engineering as a career path.

One such initiative, the Alberta Power Industry Consortium, has launched four joint research projects and others are in the planning stages. The consortium held its first annual Power and Energy Innovation Forum at the University of Alberta in November 2008. In addition to the involvement of our employees, we have committed $200,000 to support the initiative over the next five years.

The consortium also includes ATCO Electric Ltd., AltaLink, L.P., EPCOR and FortisAlberta Inc. and is jointly sponsored by the Informatics Circle of Research Excellence (iCORE) and the Natural Sciences and Engineering Research Council of Canada (NSERC).

At the University of Calgary we are leading development of a new consortium to focus on state-of-the-art research, curriculum development, student interaction and information exchange. We expect to have this group formalized in 2009.

We continue to support a successful partnership with Calgary's SAIT Polytechnic founded on the training and development of future system controllers. The program includes our employees training students, apprenticeships and a sponsorship program. We hired two first-year students from this program in the summer of 2008 as well as two program graduates.

We also committed additional funds to increase the AESO's presence in the Electrical Engineering Technology (EET) program at SAIT Polytechnic. This included sponsorship of the EET program awards banquet and industry nights where AESO employees speak to students about the program and working in the industry. In 2008, we commenced a new partnership with NAIT in Edmonton to provide scholarships and support for student events.

Reaching Albertans

Stock photograph.

During 2008, we continued to deliver factual and unbiased information about the electric industry to Albertans. Independent surveys show that Albertans continue to identify significant gaps in information about the electricity industry in our province. In keeping with our public interest mandate, we have launched a number of activities and tools to provide Albertans with information about how our industry works and who the players are. We also want Albertans to understand how important electricity is to our quality of life, the competitiveness of our provincial business and industry climate and overall economic future.

Reaching Albertans with energy information and education

Our strategy takes several forms including gathering input from Regional Advisors, making presentations to business organizations and municipalities, and distributing *Powering Albertans* magazine and its companion video program and DVD.

Two issues of *Powering Albertans* magazine were distributed to Albertans' homes as well as schools, town councils, chamber of commerce groups and libraries throughout the province in 2007 and 2008. We received calls from teachers requesting an additional 1,200 copies of the magazine. Other electricity and energy companies also requested copies of the magazine. Our research shows that the magazine is highly rated by Albertans who indicated their knowledge about the industry increased and that future editions would help meet the need for ongoing information.

The *Powering Albertans* video program aired on ACCESS Educational Television in spring 2008. Copies of the program have been provided to schools, libraries, chamber of commerce groups, industry associations and Albertans who attended our open houses. We have partnered with a non-profit educational society to survey teachers about the value of the DVD as an educational tool for the curriculum on electricity.

Our public outreach program included a major focus on presentations and meetings in 2008. During the year we met with government representatives in numerous communities throughout the province, attended conferences of municipal and district and county representatives, and submitted articles for their respective publications. We also met with several First Nations communities, special interest groups representing landowner, environmental and business interests, regional economic development groups and community planners, and committees such as the Capital Region Land-use Framework Committee.

The meetings and presentations are invaluable for us to gather important input on our projects and related plans. Direct engagement with stakeholders also provides an opportunity for us to answer questions about the industry and the role electricity plays in the economic well-being of our communities and our province.

Regional Advisors

Regional Advisors provide feedback on initiatives

During 2008, we engaged two human resource recruitment firms to identify candidates to act as Regional Advisors. After an extensive selection process we recruited a new committee made up of Albertans with extensive and diverse backgrounds that range from government to industry and education. They represent six regions that cover the province and provide the AESO with feedback and suggestions on our initiatives and an understanding of how we can improve our efforts to educate and inform Albertans about the electric industry. We are now working with the Advisors and incorporating their expertise and local knowledge into our outreach programs, consultation processes and communication initiatives. We are pleased to introduce the AESO's Regional Advisors below.

Jim Graham *High River*
Mr. Graham has 34 years in education as a teacher and school and district administrator. He is currently an educational consultant to Alberta Education, the University of Calgary and various school districts. He has served as Director for the Calgary Regional Consortium, Regional Chairperson for Headwaters Student Health Partnership and is a founding member of the Curriculum Leadership Group – Foothills Schools Division. Mr. Graham has served on several community boards including Literacy for Life and the Town of High River Planning Commission.

Jim Graham
High River

Tony Hladun *Camrose*
Mr. Hladun is a retired engineer with 31 years experience including 26 years in senior management. For most of his career Mr. Hladun was involved in consulting and pipelines with Monenco and NOVA. He then joined an engineering software company focused on automation and controls for utility clients. Mr. Hladun has served as the Director of the Battle River Community Foundation and President of the Calgary Chapter of the American Association of Cost Engineers and has been involved with the Rotary Club of Camrose.

Tony Hladun
Camrose

Jim Horsman *Medicine Hat*
Mr. Horsman is a lawyer with extensive experience in government, education, business and negotiation. He served five consecutive terms (1975 to 1993) for Medicine Hat in the Alberta Legislative Assembly, holding various portfolios including Federal and Intergovernmental Affairs and Deputy Premier. Mr. Horsman also served as Alberta's lead minister for all international trade issues and for all Canadian constitutional issues between 1982 and 1992. He is Chancellor Emeritus of the University of Lethbridge and a member of the Order of Canada and the Alberta Order of Excellence.

Jim Horsman
Medicine Hat

Sandy McDonald *Grande Prairie*
Mr. McDonald has been a self-employed businessman for over 35 years. He has a diverse background in construction, real estate and subdivision development and sales, and the mortgage industry. Mr. McDonald is involved with Renegade Development Inc., Trillian Mortgage Inc., Sandy McDonald Realty, Sexsmith Willow Estates Ltd. and a development company working in Palm Desert, California. Mr. McDonald has served as a Board member of the Grande Prairie District Agriculture Society, past Chair of the Grande Prairie Sustainable Housing Authority and as an Advisory Board Member for the Alberta Real Estate Insurance Exchange for six years.

Sandy McDonald
Grande Prairie

Keltie Paul *Fort McMurray*
Ms. Paul has extensive experience with the health region in Alberta and currently works in family and community support services for the regional municipality of Wood Buffalo. She is involved with the Alberta Centre for Active Living, Alberta Public Health Association, Alberta Traffic Safety Fund Grants Committee, Inter-regional Rural Research and Evaluation Network, Alberta Healthy Living Network Research Group, AADAC/Health Canada Reduce My Risk Project, Best Practices in Aboriginal Health Programming Project and the Athabasca Regional Issues Working Group Sub-committee: Mobile Worker Survey.

Keltie Paul
Fort McMurray

Ross Risvold *Hinton*
Mr. Risvold has 12 years experience in municipal government including as Mayor of Hinton. He works with elected officials from Canadian resource, rural, remote (R3) communities and has consulted to communities, resource management companies, and government for over 30 years. Mr. Risvold was the Director of Special Projects, West Yellowhead Community Futures Development Corporation, General Manager for Banff Centre for Management and Member, Board of Directors for the Federation of Canadian Municipalities. Mr. Risvold received the Governor General of Canada 125 Commemorative Medal and two Premier's Awards of Excellence.

Ross Risvold
Hinton

Electric System Operations

AESO file photograph.

We are responsible for operating the wholesale electricity market and directing the safe, reliable and economic operation of the Alberta Interconnected Electric System (AIES). Our objectives are to ensure:

- *The AIES is operated in a reliable way in compliance with all applicable reliability standards.*
- *Open access to transmission and markets.*
- *The consistent application of rules and requirements.*

We do this by developing and maintaining an appropriate set of system operating limits and a comprehensive set of Operating Policies and Procedures (OPPs). In addition, our system controllers participate in an extensive training program and are certified by the North American Electric Reliability Corporation (NERC).

Successful collaboration on Alberta reliability standards

Substantial progress was made during 2008 as AESO-led stakeholder working groups began their review of 91 reliability standards to ensure the standards are appropriate for Alberta and that responsibilities are clearly defined.

The standards were developed by NERC, the organization accountable for mandatory reliability standards in the U.S. We created the Alberta Reliability Committee (ARC) and its five working groups to ensure that Alberta's reliability standards are consistent with the intent of the NERC and Western Electricity Coordinating Council (WECC) standards, while recognizing the structural and operational differences between Alberta and the U.S. We have an agreement with WECC that governs our business relationship, and we operate Alberta's system in the spirit and intent of these reliability standards.

In early 2008, ARC assigned the 91 NERC-approved standards to five industry working groups for review. The working groups prioritized the standards based on the criticality and complexity of the standard (there can be up to 20 requirements per standard), how closely the standard aligns with Alberta's framework for mandatory reliability standards, and whether the standard is currently being modified through the NERC standards review process.

Each working group provided the AESO with detailed analysis and advice regarding the reliability standards, criteria, procedures, rules and processes. As a result of this process, two sets of standards were filed with the Alberta Utilities Commission (AUC) for approval. Both sets of standards were approved as filed without intervention. The approved standards included three standards relating to the balancing of supply and demand and five relating to the reliability coordination function carried out by the WECC.

ARC working groups have also completed preliminary assessments of 56 reliability standards. The review process and schedule has been developed to ensure standards that can significantly impact reliability are implemented on a priority basis. Target completion for all standards is mid-2010.

During the consultation process, we accepted a recommendation from the ARC to take a much closer look at compliance measures for all standards. Stakeholder review of the compliance monitoring program was completed in October 2008 and the program was published to the website by year-end. A staged approach is being used to implement the compliance monitoring program and standards to allow participants and the AESO sufficient time to establish the necessary internal processes, practices and information and to ensure compliance. At this time, all reliability standards will be monitored under Independent System Operator (ISO) Rule 12, and any non-compliance will be referred to the Market Surveillance Administrator (MSA). The AESO continues discussions with the MSA and AUC to develop the necessary processes regarding the identification of non-compliance events and related enforcement activities.

High marks received in NERC readiness evaluation

Following a positive report from the NERC/WECC readiness evaluation in 2005, we voluntarily agreed to participate in a second evaluation that took place in June 2008. A team of NERC, WECC, and industry representatives reviewed documents, toured the System Coordination Centre (SCC) and back-up control facilities, and conducted on-site interviews with AESO staff to evaluate our readiness to perform the balancing authority and transmission operator functions necessary to maintain the reliable operation of the bulk power system. The evaluation team focused on fundamental aspects of reliability: culture, operations, security and risk management, operational planning, training, and infrastructure.

Occurring on a three-year cycle, the reliability readiness evaluations identify areas of excellence in operations as well as areas that need improvement. The goal is to use the evaluation results to continuously improve reliability readiness and performance.

In their published report, the NERC audit team cited the AESO as a model operating organization in terms of:

- Experienced and knowledgeable operators.
- Leadership and management support ensuring operational input to plans and systems.
- Company culture and learning environment.

The NERC report cited 11 positive observations and six suggestions for improvements. Some of the positive comments included the SCC and superior Information Technology (IT) tools for system controllers, the complete package of OPPs, implementing a partnership with SAIT Polytechnic and enhanced training, dedicated resources for power system restoration programs and development of a new Energy Management System (EMS). Three of the six recommendations have been addressed, with the remaining three improvements expected to be in place by 2010. The final report is available on the NERC website at **www.nerc.com**

Project to replace EMS on schedule

We are well underway with a $21-million initiative to replace the 10-year-old EMS, which is nearing the end of its operating life. The project includes implementing a new solution that collects and displays mission critical system information that system controllers use to monitor system units and maintain reliability. The updated EMS will meet new NERC and industry standard security compliance requirements and provide for enhanced integration with other systems used for managing the AIES and Alberta's electricity markets. The first phase of the new system is targeted for completion in late 2009.

Pilot project provides operating flexibility

The complexity of the operating environment will continue to increase until transmission reinforcements can be implemented to strengthen the system and alleviate transmission congestion in several areas. We are investigating a number of opportunities to increase performance in the short term, including a pilot project to use a dynamic thermal transmission line rating on a circuit in southern Alberta.

Line ratings represent the maximum allowable power flow through a transmission line based on the physical capability of a line to carry current, ambient temperature, conductor temperature and wind speed. In the past, winter and summer line ratings were established based on these factors, including a safety margin, and lines have been operated up to these seasonal ratings.

This pilot project provides system controllers with real-time information about a transmission line that allows them to increase the amount of power flowing on the line under certain conditions. The operating flexibility helps controllers reduce the frequency of wind power curtailments until new transmission is built in the area.

Another initiative has resulted in the development of a new IT tool to support real-time reliability assessments by system controllers. The voltage stability analysis system provides controllers with the capability to run studies on a real-time basis using actual system data. Using this process, controllers can determine a more dynamic assessment of system limits since real-time conditions can differ significantly from forecast.

Our program to coordinate outages is another way in which we continue to successfully address the challenges of a more complex operating environment. Stakeholder participation in this program has been instrumental to our success.

In addition, operating limits and procedures for the 2008/09 winter operating season were revised through a comprehensive review process. We also developed and published our first 24-Month Reliability Outlook that provided information on load forecasts, supply adequacy, system constraints, market initiatives and transmission reinforcements underway. This was done from the perspective of assessing our ability to meet reliability requirements for the upcoming operating season and the next 24 months.

AESO file photograph.

240 kV transmission towers like these between Nanton and Claresholm are part of Alberta's integrated bulk transmission system. The bulk system also includes 500 kV transmission lines and substations.

Successful system restoration drill involves 200 industry participants

We successfully implemented a new custom training simulator in our fourth comprehensive two-day system restoration exercise that involved more than 200 industry participants from across Alberta. The load flow-based simulator added an element of realism to the blackout restoration exercise for participants from transmission, generation and distribution facility owners, natural gas pipeline companies, AESO system controllers and observers from the British Columbia Transmission Corporation, AUC and the WECC. Using the new simulator, industry participants were assigned the restoration of specific areas of the Alberta Interconnected Electric System (AIES) based on the actual responsibilities of their organization.

We are also moving forward with a province-wide telecommunications strategy to leverage microwave networks for use in emergency situations. We are working closely with industry to explore ways to increase the use of existing microwave communication networks to enhance communications and coordination of our system restoration procedures.

Progress on initial implementation of the wind framework

Our consultation process to implement the Market and Operational Framework (MOF) for Wind Integration moved forward on a number of fronts in 2008 with the ongoing contribution of a number of industry working groups.

The overarching goal of the MOF is to integrate as much wind as feasible while maintaining reliable grid operation and ensuring the fair, efficient and openly competitive operation of the Alberta electricity market.

In consultation with industry, we are implementing the framework for creation of market rules, interconnection standards, operating protocols, cost recovery and the advancement of appropriate transmission development.

During the year, four working groups developed discussion papers that provided recommendations in the following areas:

- supply surplus protocols
- wind power management protocols
- wind power management technical requirements
- wind power forecasting requirements

We have incorporated the work group findings and recommendations and input from industry experts and manufacturers into a comprehensive Wind Integration Recommendation Paper intended to provide clear direction and transparency on the necessary amendments to OPPs, rules and technical requirements. The discussion paper, which was released for comment in March 2009, provides an important foundation for broad consultation with stakeholders in 2009.

We expect to be implementing the specialized IT tools, rules and procedures to integrate additional wind power in the early to mid-2010 timeframe. This timing allows for the inclusion of broad industry consultation and will coincide with the staging process for implementing various elements of the MOF.

We look forward to ongoing discussion and collaboration with industry in moving forward with some of the important changes required to integrate wind power reliably.

Successful completion of wind forecasting pilot

In June 2008, stakeholders in Calgary, and via webcast around the world, heard the wind power forecasting work group's final recommendations that culminated in an industry-leading pilot project to test the methodology and results of wind power forecasting in Alberta. The session drew interest from several North American ISOs and other participants from as far away as China and Ireland.

The year-long pilot, which used international vendors, resulted in a series of recommendations regarding forecasting systems, methodologies, participant obligations, operating protocols, areas for further research and the role of Environment Canada in weather forecasting (e.g., severe weather forecasting and data). The working group indicated strong support for us to proceed to procure a wind forecasting service. These recommendations have also been incorporated into the Wind Integration Recommendation Paper.

Wind interconnection queue process in place

In early 2008, in consultation with industry, we developed and implemented a new interconnection queue business practice. This new approach includes associated project milestones to provide clarity for wind power developers. As a result of the success of the new process, interconnection proposals are being prepared as required on an ongoing basis. This effort is also the culmination of a new organizational structure, which created a more focused customer service model for all transmission interconnection requests for generation and load customers.

Enhanced operating tools support wind integration

During 2008, we also developed an operating IT tool prototype that mirrors system controllers' decisions regarding dispatch, price responsive load, use of dispatch down service and the integration of wind energy (e.g., consideration of ramping; integration of forecasts). This IT tool is expected to be available for functional testing by spring 2009 with final delivery to system controllers in mid-2009.

This work is done in conjunction with the dispatch tool (DT) upgrade project due to the functional integration of these two operating tools. We are moving ahead on near-term improvements to DT, which are to be completed by May 2009. The DT upgrade project is addressing operational issues that affect market participants and risk the reliable operation of the market and pool price fidelity.

AESO receives recognition of leadership

We are proud to have received two awards in recognition of our industry leadership on integrating wind power into the Alberta power system.

In March 2008, we received an achievement award from the Utility Wind Integration Group (UWIG), an international wind energy advocacy group. The UWIG highlighted the AESO's leadership in addressing the challenges of integrating wind into the Alberta electricity market.

A second wind-related award was announced by the Canadian Wind Energy Association (CanWEA) at its annual conference in October 2008. The AESO received the R.J. Templin award for technical excellence for our work in establishing the market and operational framework and advancing necessary transmission to integrate additional wind in Alberta.

CanWEA praised the AESO for developing the MOF for Wind Integration, for undertaking a wind forecasting pilot project using international vendors, and for advancing transmission system reinforcements to interconnect wind.

We appreciate the support we have received from industry stakeholders in Alberta who have worked collaboratively with us to develop the MOF and to implement the required processes and procedures that will allow us to accommodate the variability of wind on our electricity system.

Alberta's leadership on wind integration was also acknowledged with a request for the AESO to chair the NERC Wind Integration Task Force. This 50-member North American task force is developing concepts and high-level recommendations for practices, requirements and reliability standards with respect to planning, operations planning and real-time operations to integrate large volumes of wind generation. Final approval of the task force report, which should be of interest to markets around the world, is expected in the second quarter of 2009. Alberta is already in the process of implementing many of the recommendations through our MOF for Wind Integration.

Photo courtesy of Suncor Energy.

The Magrath wind power project in southern Alberta is jointly owned by Suncor Energy, Accino Energy and Enbridge Income Fund.

Market Development and Operations

Photo courtesy of ENMAX Energy.

We are responsible for facilitating the development and operation of the competitive wholesale market for electricity, including financial settlement. We ensure that the market operates in a fair, efficient, open and competitive manner that will result in a predictable market structure that adds long-term value.

Market Advisory Committee provides valued input

The Market Advisory Committee (MAC) is a group of 19 industry participants representing a broad range of interests. The MAC has contributed significantly to the AESO, providing input on market policy issues and advancing important discussions that will help guide the development of Alberta's electricity market. The commitment and collaboration from participants representing varied industry interests provides the foundation for meaningful consultation on a wide range of market-related matters, forward-looking issues and a collective vision for the market.

During 2008, MAC discussions focused on various market rule changes, rule language, compliance frameworks and interties. A MAC sub-committee was formed to direct a study of price cap challenges and report their findings to the larger group. We will develop a process for broad stakeholder consultation as this work moves forward.

Intertie policy and the regulatory and legislative frameworks for existing and new interties was the subject of a MAC discussion that included representatives from the Alberta Department of Energy (DOE). The discussion resulted in near consensus among committee members that examining policy and regulation direction would result in a clearer approach for advancing new intertie capacity (either merchant or rate-based) in the future. We expect further discussions on this matter to continue in consultation with the DOE in 2009 as part of the Alberta government's Provincial Energy Strategy.

Market Roadmap to provide integrated vision

The current version of our Market Roadmap released for comment in 2007 provided the high-level context for a broad range of market design initiatives for Alberta's fair, efficient and openly competitive electricity market.

This visioning process will also contribute to our plan to replace the 10-year-old Energy Trading System (ETS) with a robust new system that will be integrated with the new Energy Management System (EMS) and allow for future functionality as the market evolves. For example, our systems need to incorporate new requirements that will arise as we implement the Market and Operational Framework (MOF) for Wind Integration and as we move through the process to finalize new rules and regulations for reliability unit commitment, congestion management and dispatchable interties.

New market rules process initiated in 2008

In accordance with the Electricity Policy Framework and the *Transmission Regulation* we filed a number of rules with the Alberta Utilities Commission (AUC) in 2008. We continue to follow a comprehensive industry consultative process for developing rules, which is guided by AUC Rule 17.

We filed the Section 18 *Transmission Regulation* rules (generator outage coordination and reliability unit commitment) as well as rules regarding long-term adequacy and congestion management in April 2008. The long-term adequacy rules were implemented with no objection in July 2008.

AUC hearings on generator outage coordination, reliability unit commitment and congestion management rules occurred in fall 2008 and were completed before year-end. We look forward to timely decisions from the AUC, after which we will begin work on the systems and processes required to implement the new rules.

Future market framework rules and design initiatives

We continue to advance work on the following multi-year market design initiatives:

- **Market power mitigation *(Electric Utilities Act Section 6)*:** We have been involved in the DOE's industry consultation on this topic and will participate in further consultation regarding implementation of the regulation in 2009. Once the regulation is finalized, we will begin work on the rule and system changes required for implementation. We continue to support development of a simple, efficient and effective mitigation framework that encourages fair, efficient and openly competitive participant behaviour and provides greater certainty for market participants.

- **Dispatchable interties:** We continue to work with the British Columbia Transmission Corporation and Saskatchewan Power Corporation regarding business process changes and technical requirements needed to implement dispatchable interties. We are focused on addressing challenges given the differences in the three energy market operations, transmission protocols and reliability constraints. Implementation is dependent on the scheduled release of our new EMS, which will have the capability for dynamic scheduling on the interties.

- **Market suspension:** This rule, which identifies the triggers and market outcomes in the event of a market suspension, will be revised in light of cumulative market design changes during the past few years.

- **Operating reserve market redesign:** We formed a stakeholder working group and were engaged in industry consultation on this matter throughout 2008.

- **Demand response:** This initiative involves a review of in-market price responsive load and out-of-market demand response alternatives to increase load participation in the market and coordinate requirements for load shed service and the load curtailment priority plan as required by the *Transmission Regulation*. In the first quarter of 2008, we completed a comprehensive review of demand response programs in North America. Preliminary conclusions are that the price responsive load in Alberta is producing similar results as organized programs elsewhere. However, out-of-market programs in other jurisdictions have had varying success and will be evaluated. We formed a broad stakeholder working group and expect that consultation may include several sub-committees dealing with topics such as market-based and reliability-based demand response.

AESO tariff comes into effect

On August 1, 2008, a 21-month General Tariff Application (GTA) process was officially completed as our 2007 tariff came into effect. During 2008, the AUC conducted a written proceeding on a refiling as required by the regulator's decision issued in December 2007. We submitted a second refiling in May 2008 and the tariff became effective in August. The extended process reflects the complexity of the tariff and the detailed and thorough review it receives by the AUC and other parties. The revised tariff provides the market with clarity regarding rates, terms and conditions for transmission system access service. The process also marked a first in the AESO's history as the regulator approved the forecast revenue requirement relying on the rigour of our 2007 budget review process with stakeholders and the approval of our Board.

Transition of authoritative documents underway

We are moving forward with a project to develop and implement a comprehensive framework that will be consistently applied for all existing AESO authoritative documents (i.e., those documents such as rules that contain binding obligations for participants, including the AESO). The initiative will result in streamlined, updated documents reflecting new legislation and policy and clearer definitions of roles and obligations.

We are continuing to test the new framework and engage stakeholders to get early feedback and input. Our goal is to produce a framework for all our authoritative documents and achieve the following:

- Consistent processes for authoritative document management, tracking and approval.
- Ensure no duplication or inconsistencies in documents.
- Structure documents in a way that provides clarity about our obligations and authority and the obligations of others.
- Present information in a consistent format.
- Establish a consistent document control mechanism.

Alberta Wholesale Market Statistics

ONGOING MARKET EVOLUTION IN 2008

During 2008, the AESO made significant progress on moving forward with some major rule changes for Alberta's wholesale electricity market. The rule changes, which were announced in late 2007, are intended to address recommendations made in the Alberta Department of Energy (DOE) Market Policy Framework issued in June 2005. These changes are focused on enhancing the visibility and availability of supply and pool price fidelity while addressing pool price volatility.

Power consumption and installed generation capacity increased during the past year. Growth in consumption was lower than previous years and the market saw the addition of 500 megawatts (MW) of new gas-fired generation. With the development of long-term adequacy rules in 2008, the AESO began publishing metrics on the ability of supply to meet forecast demand. In 2009, the AESO expects the addition of approximately 400 MW of new generation. Use of the interties with other jurisdictions increased substantially year-over-year. In 2008, the number of hours the interties with B.C. and Saskatchewan were highly utilized (using 80 per cent or more of the available transfer capability) was approximately 6,300 hours, up from approximately 5,000 hours in the prior year.

Table 1: Price summary statistics – 2000 to 2008

Pool Price *($/MWh)*	2000	2001	2002	2003	2004	2005	2006	2007	**2008**
Average hourly pool price	$ 133.22	$ 71.29	$ 43.93	$ 62.99	$ 54.59	$ 70.36	$ 80.79	$ 66.95	**$ 89.95**
Off-peak average pool price	$ 72.52	$ 53.14	$ 28.47	$ 46.97	$ 41.88	$ 49.28	$ 50.15	$ 41.86	**$ 54.45**
On-peak average pool price	$ 181.08	$ 85.51	$ 56.04	$ 75.54	$ 64.53	$ 86.86	$ 104.97	$ 86.61	**$ 117.73**
Maximum hourly pool price	$ 999.99	$ 879.20	$ 999.00	$ 999.99	$ 998.01	$ 999.99	$ 999.99	$ 999.99	**$ 999.99**
Minimum hourly pool price	$ 5.84	$ 5.82	$ 0.01	$ 7.07	$ 0.00	$ 4.66	$ 5.42	$ 0.00	**$ 0.00**

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 and all day on Sunday and all day on North American Electric Reliability Corporation (NERC) defined holidays.*

Pool price up 34 per cent

Alberta's competitive wholesale market electricity prices fluctuate based on the principles of balancing supply and demand. During times of surplus energy prices remain low, while during times of scarcity, prices increase. Since competition was introduced in Alberta's electricity marketplace the wholesale price, known as the pool price, has set the price for wholesale electricity every hour of the year. The wholesale price has been capped at a maximum of $999.99 per megawatt hour (MWh) and the floor has been set at $0/MWh. In 2008, the pool price reached an eight-year high, averaging $89.95/MWh, with both on and off-peak prices increasing over 2007 levels.

On-peak pool prices averaged $117.73/MWh and off-peak prices averaged $54.45/MWh. Higher natural gas prices and more planned and unplanned generation unit outages contributed to the increase in pool prices. Natural gas prices averaged $7.73 per gigajoule in 2008, up 27 per cent from 2007. Total outages averaged 1,600 MW in 2008, a 60 per cent increase from the prior year.

The highest monthly average pool price was $135.95/MWh, recorded in April 2008. This is the third highest priced month since 2001.

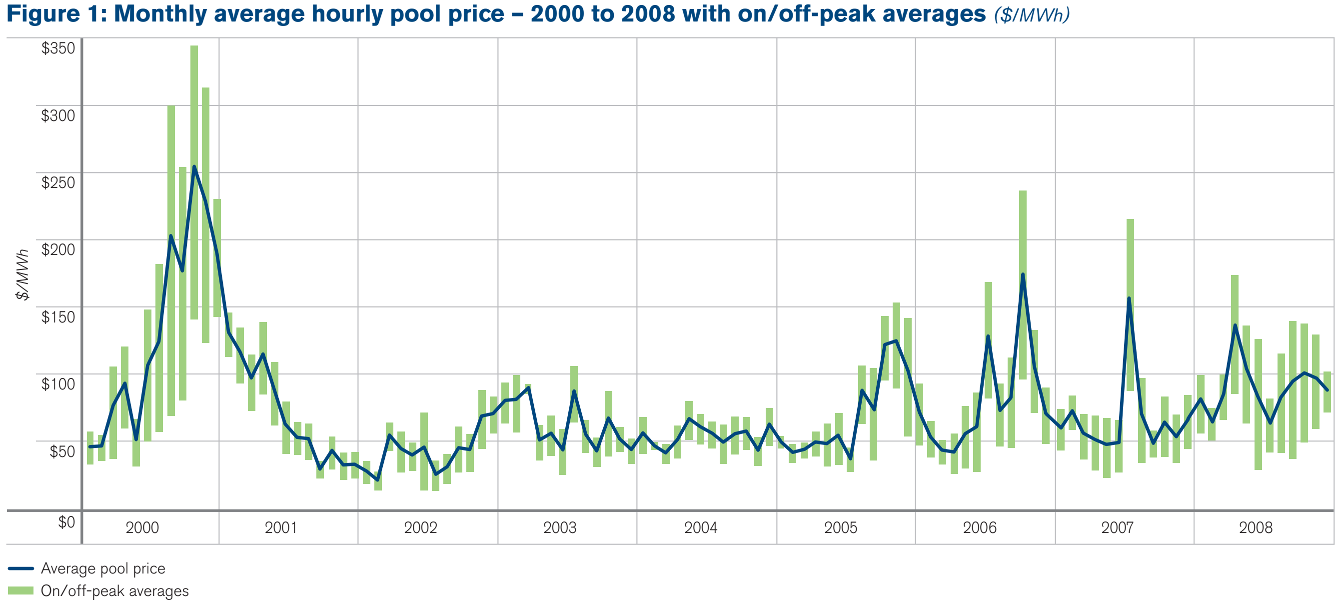
High prices observed during April can be attributed to a number of planned and unplanned generator outages and transmission constraints resulting from an upgrade that took place at Keephills, Ellerslie and Genesee, known as the KEG conversion project. The project converted a transmission line from 240 kilovolts (kV) to 500 kV.

During project construction, the amount of supply that the Keephills and Genesee generation units could deliver to the market was limited. Generally, planned outages for coal generators occur during the spring and fall when demand is typically lower.

In April, most other coal units saw some periods of planned outages for regular maintenance or unplanned outages due to operational issues. This factor plus the lower supply available from the Keephills and Genesee units further added to the amount of low-cost coal generation that was unavailable during the month, resulting in higher prices.

In the two previous years, average monthly pool prices have been highest during July. In 2008, the average monthly pool price settled at $64.51/MWh, 59 per cent lower than the average monthly price of $155.73/MWh recorded in July 2007, and 50 per cent lower than July 2006, which settled at $128.23/MWh. Weather, specifically cooler than average temperatures, and higher coal-fired plant availability due to fewer weather-related derates contributed to lower prices in July 2008. Average demand in July 2008 was two per cent lower than the same month a year earlier.

Figure 1: Monthly average hourly pool price – 2000 to 2008 with on/off-peak averages *($/MWh)*



Pool prices impacted by natural gas prices

The Alberta pool price is determined by the highest priced generator that is dispatched to meet the demand for electricity. Generators submit to the AESO hourly offers detailing the amount of energy they will provide at a certain price. An automated system at the AESO arranges all the hourly offers from the lowest price to the highest price. Starting at the lowest priced offer, the AESO system controllers dispatch generating units until the demand requirement is satisfied. Natural gas-fired units account for approximately 40 per cent of installed capacity in the Alberta market. The price of offers made by natural gas-fired units fluctuates to reflect changes in the price of the fuel. When natural gas prices increase, offers tend to reflect the higher cost, which tends to result in an increase in pool price.

Figure 2 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 an underlying fuel used to produce electricity. In Alberta's case this fuel is natural gas.

The heat rate is determined by dividing the pool price by the natural gas price. The relative decline in the market heat rate over the period from 2000 to 2005 reflects the addition of more efficient cogeneration units in Alberta. Since 2005, spikes in the market heat rate are indicative of periods of tightness in the balance of supply and demand. This results in higher prices and higher heat rates.

Figure 2: 30-day rolling average pool price and natural gas price (AECO-C)

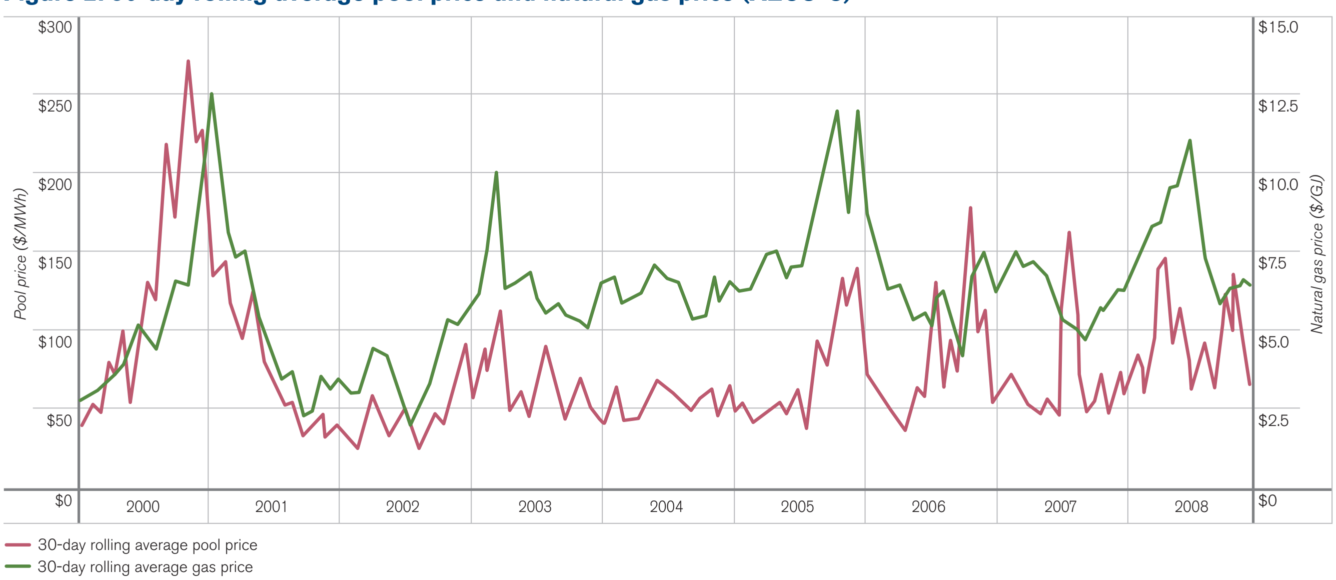
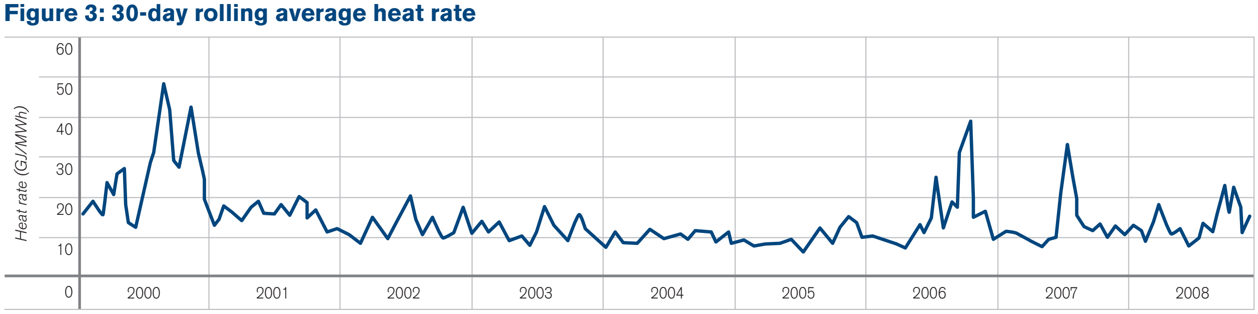


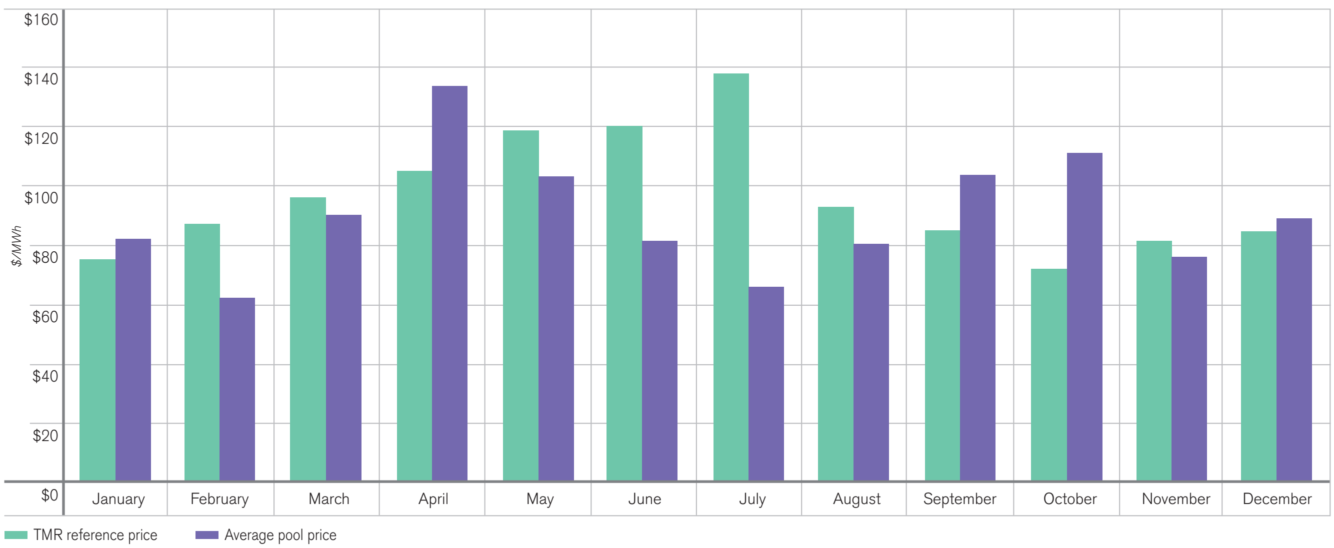
Figure 3: 30-day rolling average heat rate



As part of the package of rule changes, the AESO introduced a reference price that is used to determine when the dispatch down service is active. The reference price is determined monthly at a 12.5 heat rate multiplied by the natural gas price.

Throughout 2008, the system marginal price (SMP) was set between a 12 heat rate and a 12.5 heat rate for approximately 10 per cent of the time. The SMP refers to the 60 price values recorded each minute in any given hour. Overall, this demonstrates the correlation between electricity prices and the underlying cost of fuel, that of natural gas, as seen in Figure 4 showing the monthly average pool price, and the monthly transmission must-run (TMR) reference price.

Figure 4: Transmission must-run reference price and monthly pool price – 2008



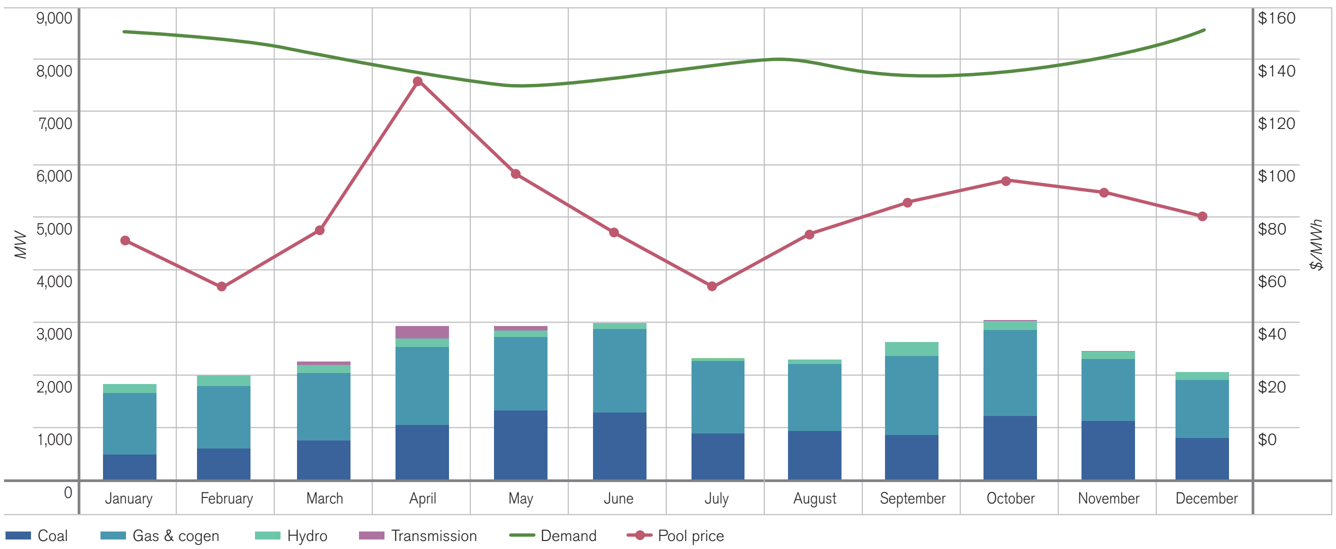
Supply availability drives prices

One of the goals of the rule changes was to improve the visibility of supply to the AESO's system controllers. Maximum capability and available capability rules were introduced to help establish an hour-by-hour visibility of the supply available to the market.

All generating assets submit a maximum capability representing the maximum quantity of megawatts that the generating asset is physically capable of generating under optimal operating conditions. The available capability is set to the maximum capability. Each asset must offer all of its available capability to the market unless there is an acceptable operational reason for reducing available capability to a level lower than the maximum capability.

The majority of supply in the market is from baseload assets that run nearly all the time. Most of these are coal-fired units, which offer the majority of energy to the market at $0/MWh as they intend to be running all the time. 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 5 illustrates the association between outages (defined as the difference between the maximum capability and available capability) 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.

Figure 5: Average amount of generation on outages and derates – 2008

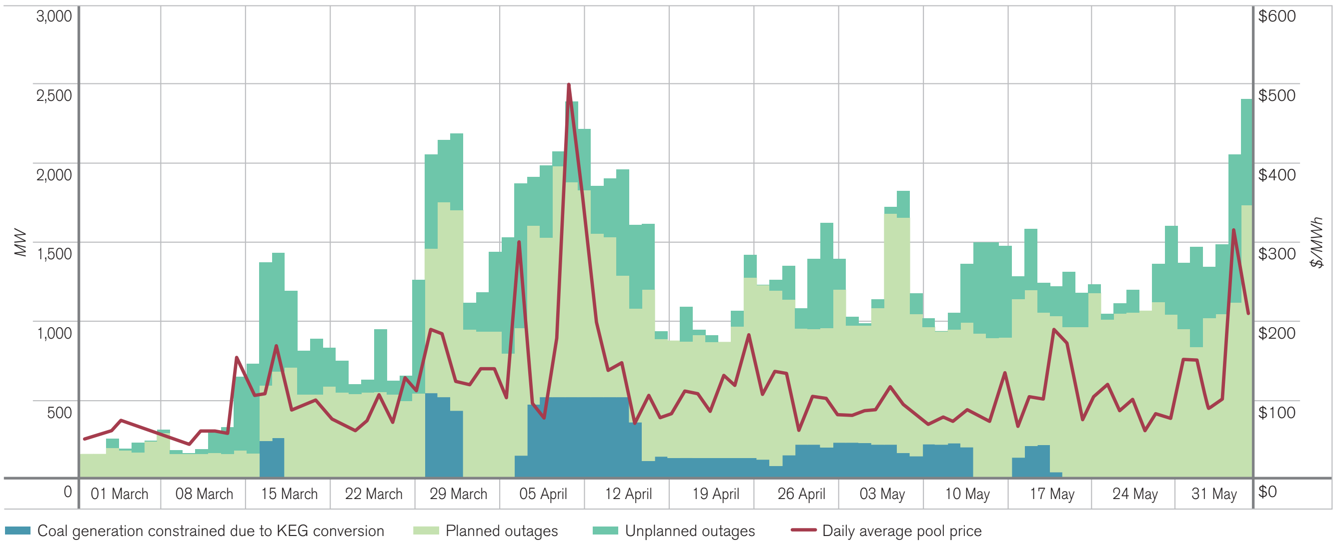


In April, there was nearly 3,000 MW of supply unavailable and the pool price averaged $135.95/MWh. A significant amount of supply was unavailable to the market due to transmission maintenance related to the KEG conversion project.

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.

Figure 6 illustrates the average supply from coal-fired units that was unavailable each day during the period. An average of 125 MW of coal-fired generation was constrained over the March to May period, with nine days when over 500 MW of coal generation was unavailable due to the KEG conversion project. An average of nearly 800 MW of coal generation was on planned outages during the same period and there was an average of 278 MW on forced outages. Days with the highest outages tended to see the highest prices, particularly during the month of April when demand was higher than in May.

Figure 6: Daily planned and unplanned outages during KEG conversion project – 2008



Price and supply factors fuelling high intertie use

Alberta currently has two interties – one with B.C. and the other with Saskatchewan. These interties allow energy to be imported during times of tight supply and exported when there is energy that is surplus to the needs of Alberta. During the year, the amount of imports and exports will vary depending on limitations of the interties, market prices for electricity in other jurisdictions, and other factors. With higher prices in 2008, import levels increased 53 per cent and export levels decreased by 43 per cent.

Table 2: Intertie statistics – 2004 to 2008

Intertie statistics (MWh)	2004	2005	2006	2007	**2008**
Imports on B.C. intertie	1,073,471	1,070,848	1,101,207	927,108	**1,574,370**
Imports on Sask. intertie	418,267	463,726	415,828	540,113	**673,748**
Total imports	**1,491,738**	**1,534,574**	**1,517,035**	**1,467,221**	**2,248,118**
Year-over-year growth *(%)*	12.36	2.87	-1.14	-3.28	**53.22**
Exports on B.C. intertie	968,434	987,581	460,050	885,551	**518,453**
Exports on Sask. intertie	92,940	50,493	29,415	87,666	**40,306**
Total exports	**1,061,374**	**1,038,074**	**489,465**	**973,217**	**558,759**
Year-over-year growth *(%)*	-13.51	-2.20	-52.85	98.83	**-42.59**
Net yearly imports	**430,364**	**496,500**	**1,027,570**	**494,004**	**1,689,359**

The amount of electricity that can be imported or exported on each intertie is determined by the available transfer capability (ATC). In 2008, the maximum ATC was comparable to previous years for exports over the B.C. intertie, and for both imports and exports over the Saskatchewan intertie. The import ATC on the B.C. intertie was lower than in previous years, with the maximum ATC down seven per cent and the average ATC down nine per cent.

Table 3: Intertie available transfer capability statistics

	B.C. export ATC		B.C. import ATC		Sask. export ATC		Sask. import ATC	
Year	Max.	Average	Max.	Average	Max.	Average	Max.	Average
2004	700	209	725	555	90	63	153	147
2005	735	187	715	604	69	52	153	139
2006	735	188	700	607	60	38	153	141
2007	735	333	675	517	60	47	153	146
2008	**735**	**387**	**625**	**468**	**60**	**35**	**153**	**148**

The intertie with B.C. not only allows electricity to be imported and exported, it also allows participants to provide up to 80 MW of spinning and/or supplemental reserves. If this supply is offered into the ancillary services market it can be used in case of a contingency. When the intertie is used to dispatch ancillary services, the remaining ATC is adjusted accordingly.

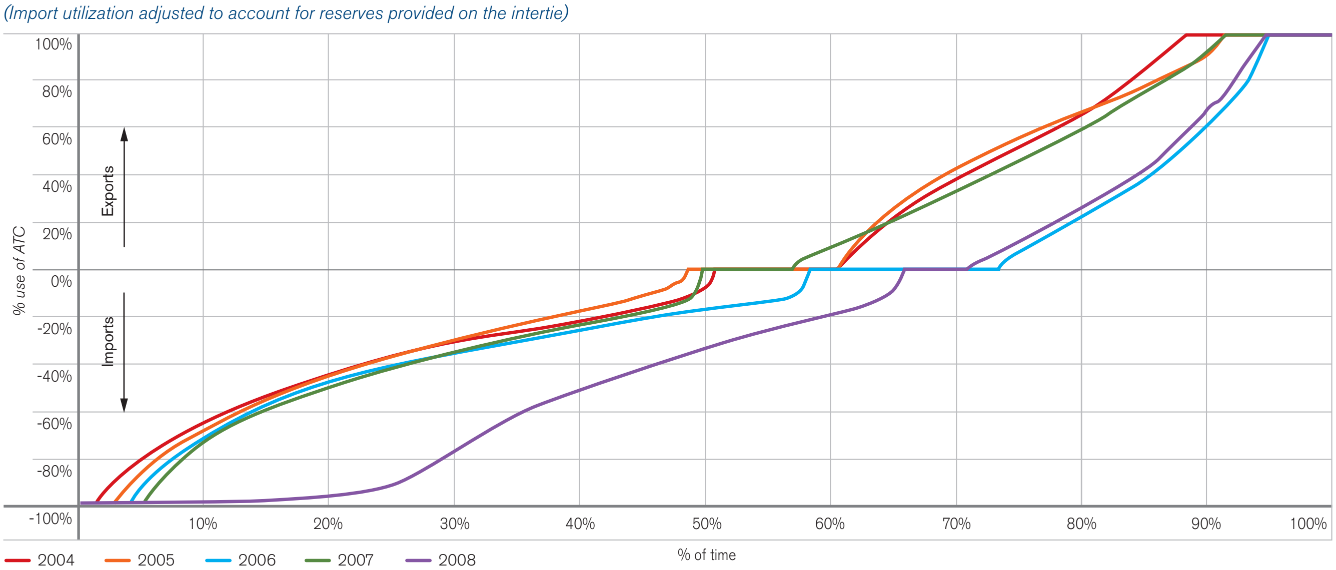
Utilization of the import ATC on the B.C. intertie is defined as the import amount net of any exports for each hour plus any reserves being provided over the intertie divided by the ATC. The export utilization is the export amount net of any imports divided by the export ATC.

In 2008, there was a significant increase in the amount of time the B.C. intertie was highly utilized to import electricity into Alberta. During the year, there was a 225 per cent increase in the number of hours imports used at least 80 per cent of the intertie ATC. The rise in imports was primarily due to higher prices in Alberta during the year. 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.

When the intertie is highly utilized there may be additional imports or exports that are unable to flow. In 2009, the AESO will be working to increase the ATC on the intertie. The intention is to allow more imports and exports which, in turn, will improve the overall connectivity between the Alberta market and other markets.

Figure 7: Import-export utilization on B.C. intertie – 2004 to 2008

(Import utilization adjusted to account for reserves provided on the intertie)



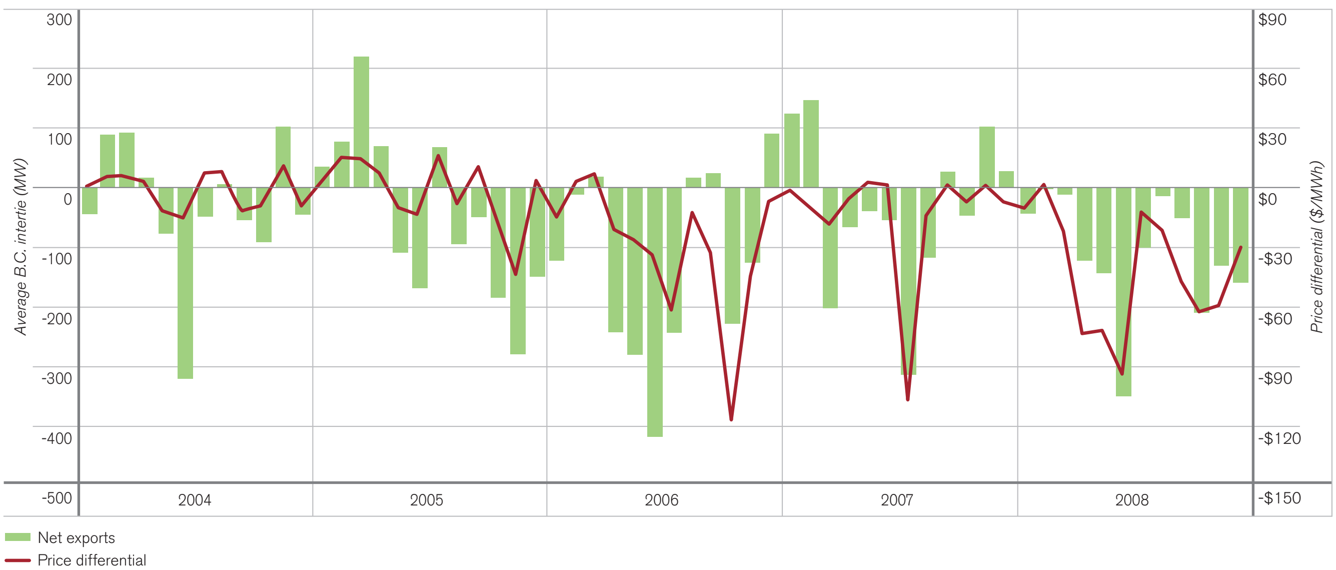
Intertie flows are indicative of arbitrage opportunities between Alberta and the Pacific Northwest

Alberta's most significant interconnection with other jurisdictions is with the U.S. Pacific Northwest via the B.C. intertie. The Mid-Columbia hub (Mid-C) is the major indicator of price in the region. Imports and exports to the Pacific Northwest are based on the arbitrage opportunity between the two markets. For example, when prices are high in Alberta and low at Mid-C imports are expected, and exports are expected when prices are lower in Alberta than at Mid-C. Figure 8 illustrates this relationship by comparing the monthly average flows on the B.C. intertie to the price differential between the Alberta pool price and the Mid-C price.

The price at Mid-C is highly influenced by the need to manage water at the large hydroelectric facilities in the region. During spring run-off in late May and early June, prices drop in the Pacific Northwest due to abundant water supply. Due to these lower prices, Alberta imports significant amounts of electricity even though the province tends to see lower prices during this period as a result of lower demand. In the past two years, there have been periods when the pool price has settled at $0/MWh during the spring run-off period. This situation requires system controllers to follow supply surplus procedures to clear the market.

Figure 8: Mid-C/Pool price differential

(Price differential: Mid-C price minus pool price)



Higher prices due to a tightening supply/demand balance is indicating the need for more supply

In 2008, the AESO introduced both short- and long-term adequacy reports detailing the sufficiency of supply to meet the forecast demand. As part of the rules package, a short-term supply adequacy report is published on the AESO's website at **www.aeso.ca** This report measures the megawatts remaining in a routine system calculation to determine the forecast adequacy of supply over the current day and the following six days. The results are aggregated into five levels. The fourth level denotes sufficient supply to meet demand, and a level of zero forecasts the tightest balance between supply and demand. When the forecast shows adequate supply we expect prices to be moderate, and when the forecast supply/demand balance tightens we expect prices to increase. In Figure 9 the average price is shown for each of the levels presented at two hours before each delivery hour (T minus 2).

In 2008, the AESO introduced reports on long-term adequacy (LTA) metrics and developed long-term adequacy rules. The LTA rules describe the means by which the AESO monitors and reports on the LTA of Alberta's electricity market. If this analysis indicates a potential LTA concern, the rules define steps the AESO may take to address the concern and ensure the adequacy of supply in Alberta's marketplace.

One metric used to assess supply adequacy is reserve margin. Typically expressed as a percentage, the reserve margin estimates the amount of firm generation capacity at the time of system peak that is in excess of annual peak demand.

When analyzing currently installed generation and generation projects under construction, the reserve margin is forecast to decrease in the next few years indicating a tighter supply/demand balance. This reserve margin does not include generation developments that have received regulatory approval, have applied for regulatory approval, or those that have been announced by project developers.

Figure 9: Average pool price for each level of the short-term adequacy report at T minus 2

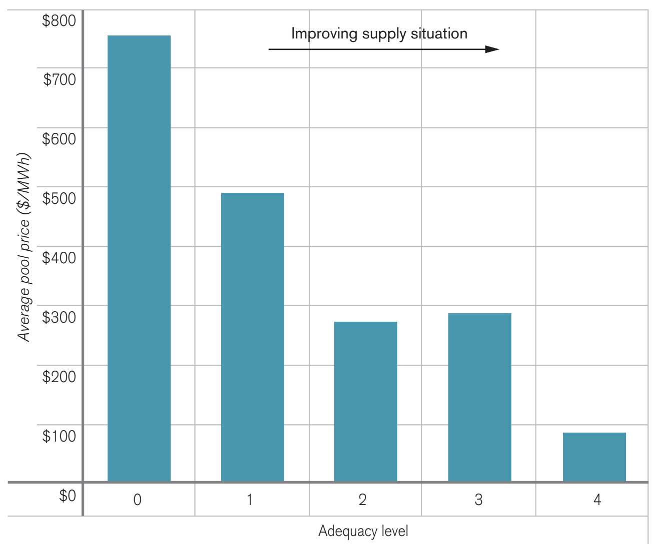


Figure 10: Historic and forecast reserve margin and amount of time near the price cap

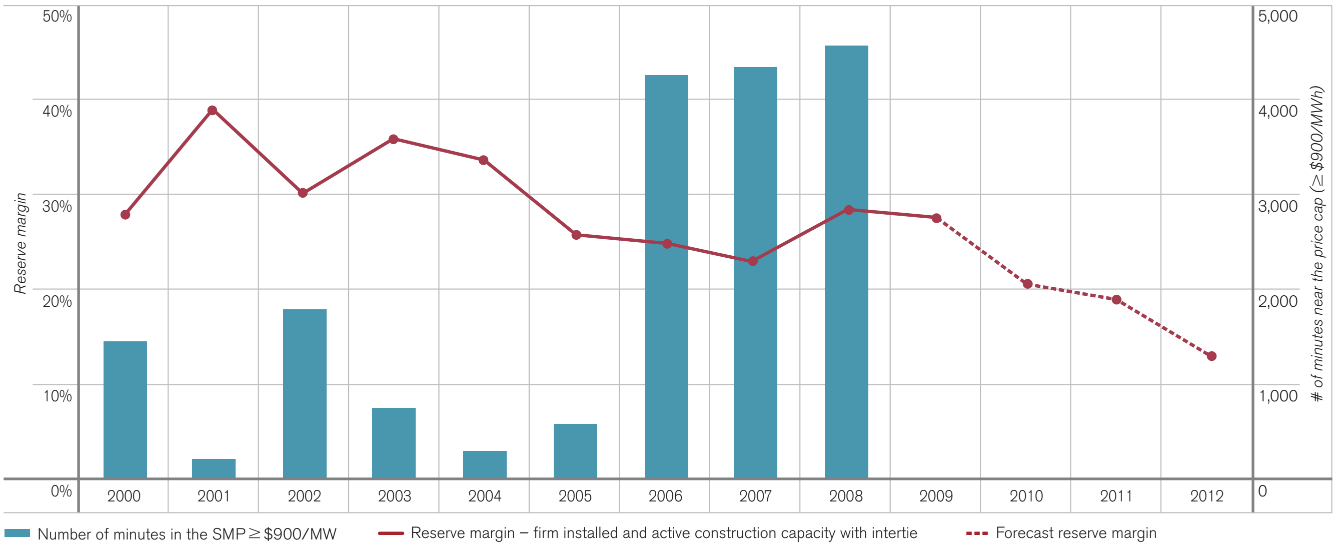


Figure 10 illustrates how the reduction in reserve margin impacts the amount of time the market experiences high prices (≥ $900/MWh). This price signal indicates there is a need for additional generation. In 2009, more than 400 MW of new capacity is expected to be installed.

The LTA metrics include a list of new generation projects that are expected to be built. In 2008, 500 MW of new supply was added, while we expect to see approximately 400 MW of new generation additions in 2009. An additional 550 MW of new supply is expected in 2010 and 2011.

Two generation plants will be retired from service in the next two years. In 2009, the 209 MW Rossdale gas-fired plant will be retired from service after over 40 years of operations. In 2010, the final 279 MW generating unit at the Wabamun coal-fired plant will be retired after 40 years of service.

More demand served by imports and wind

Coal-fired production provides the majority of the energy required by Alberta's market. In 2008, coal-fired generators provided 72.5 per cent of the energy required. This represents a 1.3 per cent reduction from 2007 due to increased coal unit outages in 2008.

The increased prices and intertie use in 2008 resulted in imports providing energy to meet four per cent of market demand, up from 2.5 per cent the previous year. Wind generation also saw a slight increase from 2007, supplying 2.6 per cent of the needs of the market or an average of 176 MW each hour in 2008.

Wind generation in Alberta

In consultation with stakeholders, the AESO has produced some of the first wind interconnection standards in North America, delivered several groundbreaking wind integration studies that identified operational impacts and necessary mitigation measures, launched the wind power forecasting project, and created the Market and Operational Framework for Wind Integration (MOF) in Alberta.

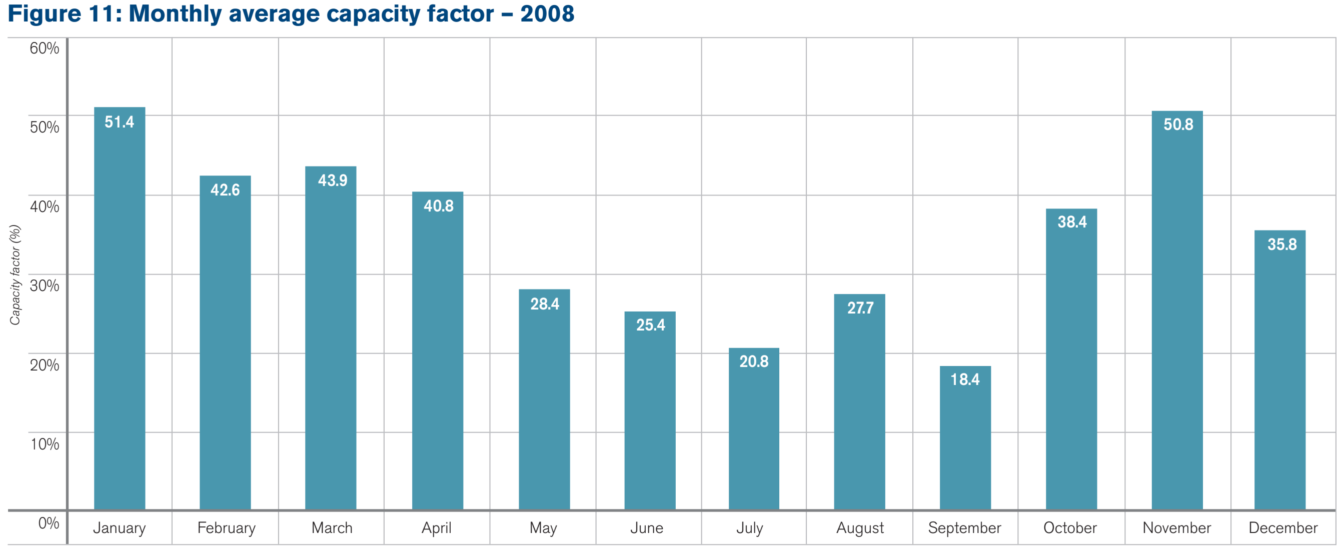
The basic premise of the MOF is if the AESO system controller has access to a reasonable forecast of wind power they can establish operating plans using the energy market, regulating reserves, load/supply following services and wind power management. To implement the MOF, the AESO is consulting with stakeholders on recommendations regarding wind power forecasting, wind power curtailment protocol and supply surplus protocols.

Alberta has nearly 500 MW of wind generation interconnected to the transmission system, which in 2008 supplied 2.6 per cent of the energy needs of the market. This is up slightly from 2007 when 2.4 per cent of the energy market was supplied by wind power.

There is continued strong interest in wind development in Alberta and currently there is more than 11,500 MW of wind projects in the interconnection queue. As more wind is integrated into the Alberta system in the next few years, the key elements of the MOF must be implemented and refined to ensure reliable, fair, efficient and openly competitive operation of the grid and wholesale markets.

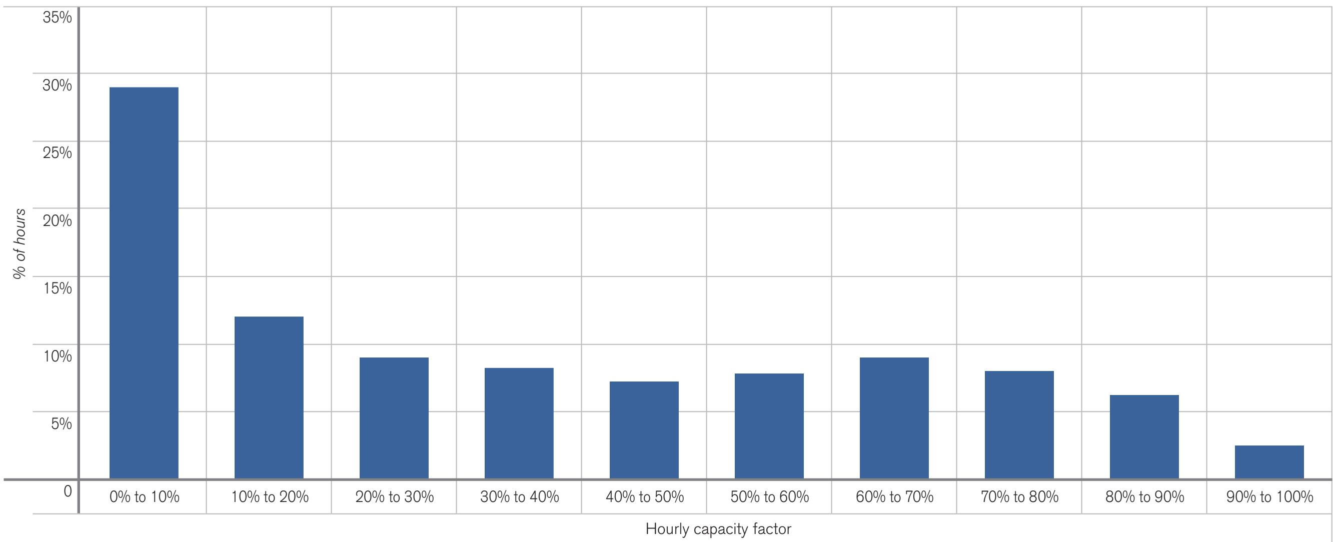
The variable nature of wind power results in fluctuating levels of wind generation available to the market over various timeframes. The aggregate capacity factor for wind power facilities compares the total energy production over a period of time with the amount of power the wind project would have produced if it had run at full capacity for the same amount of time. Alberta wind power facilities have relatively high capacity factors, with an aggregate annual average of 35.3 per cent in 2008. The previous year's annual capacity factor was 39.5 per cent. This decrease is primarily attributed to the impact of additional wind facilities that came on stream in late 2007 when wind resources tend to be strongest. Figure 11 illustrates a strong seasonal pattern with capacity factors averaging more in winter months than in summer months.

Figure 11: Monthly average capacity factor – 2008



The 2008 hourly wind capacity factor shown in Figure 12 illustrates the percentage of hours when wind capacity factor was in certain ranges. While wind power frequently generates an hourly capacity factor of less than 10 per cent, wind power facilities in Alberta generated an hourly capacity factor of more than 60 per cent for over one quarter of the hours in 2008. This data indicates that although the wind power regime in Alberta may produce very little power at times, it also produces at very high capacity factors during some periods, particularly in the winter months as seen in Figure 11.

Figure 12: Hourly wind capacity factor – 2008



Wind generation is non-dispatchable and thus offers into the market at zero dollars. Although there are several factors that affect energy prices, the pool price tends to be lower when there is a significant amount of wind power production. Figure 13 shows wind generation in specified ranges and the corresponding average pool price. In periods with low wind generation, pool price has been higher than the annual average. Conversely, during times of high wind generation, the average pool price has been below the annual average price.

Figure 13: Wind versus pool price (average pool price for varying amounts of wind generation)

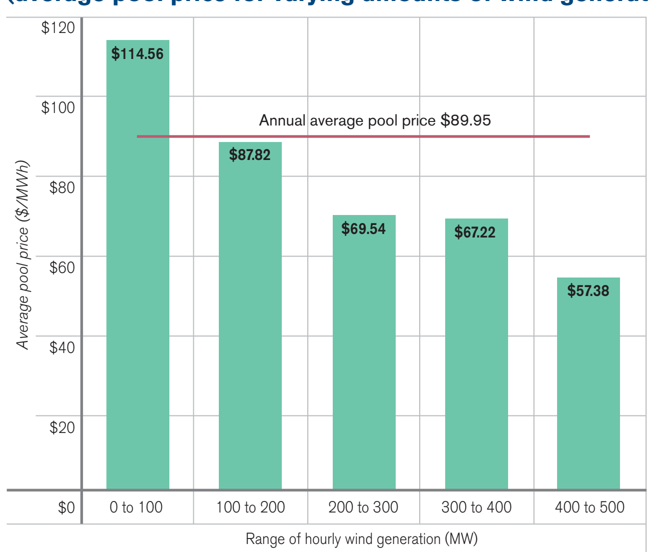
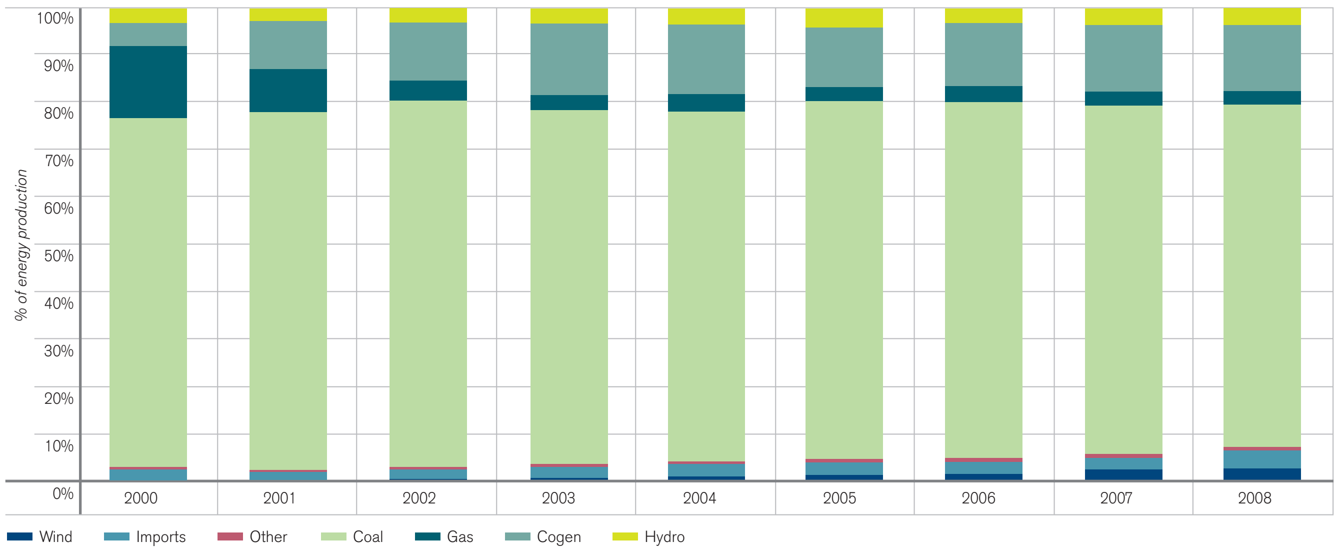


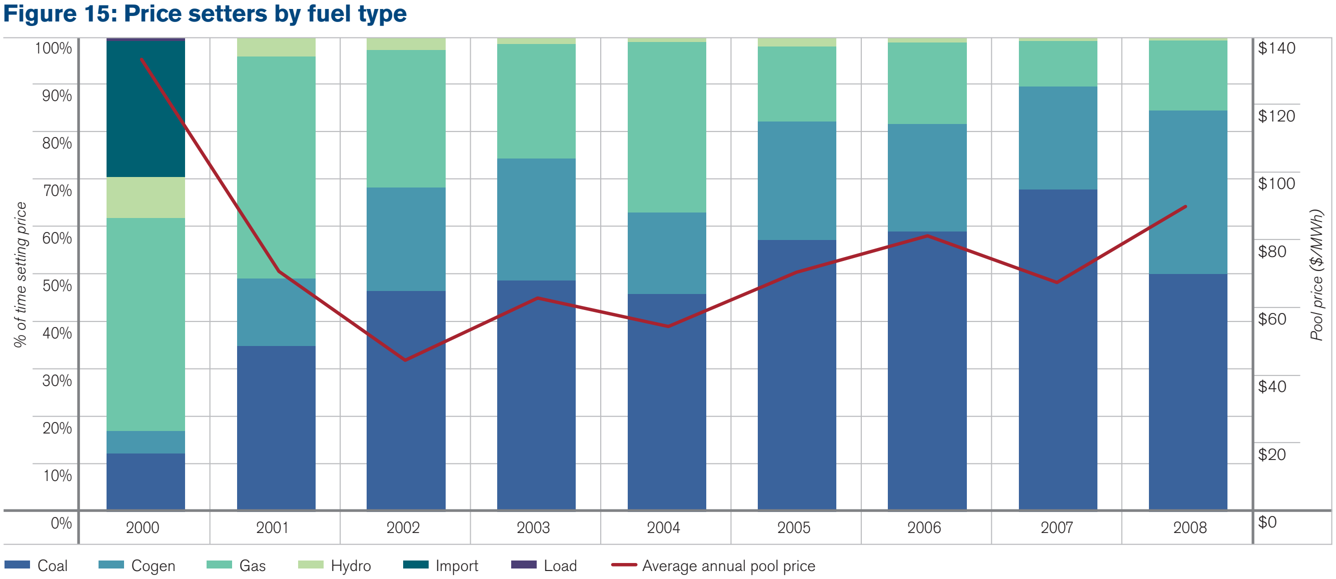
Figure 14: Energy production by fuel type



Fuel type on the margin is indicative of price

Typically, coal-fired units are less expensive to run than most gas-fired units and tend to set the lower prices of the year. During 2008, the amount of time coal-fired generators set price was 50 per cent of the time. This compares to 68 per cent of the time the prior year. Gas-fired plants and cogeneration units set price for most of the remaining time. Hydroelectric generation rarely sets price as it is primarily used to meet peak demand during the highest priced periods of the year.

Figure 15: Price setters by fuel type



Market changes result in more diversity of companies setting price

One of the market changes introduced with the new rules was the concept of 'must offer' for all generators in Alberta. With this rule all generation units must offer all of their available capability to the market. As a result of the rule many participants submit offers using more than one offer block. The change in offer strategy has resulted in a more diverse range of offers and greater diversity in participants setting price. After the rule change, there were three additional participants setting price. However, in 2008, there continued to be one participant setting price 30 per cent of the time. This is lower than the 40 per cent recorded in 2007 and 2006.

Figure 16: Price setters by submitting participant

Low demand growth in 2008

During 2008, load growth was 0.14 per cent, continuing the slowdown first recorded in 2007. This level of growth is lower than forecast and is primarily due to less than expected growth in the Fort McMurray region, primarily in oilsands-related projects. It is also noted that the high pool price in 2008 contributed to lower demand from load customers who choose to respond to price. After accounting for these price responsive customers, who constitute approximately three per cent of the total demand, load growth in 2008 was 0.49 per cent. This is commensurate with the load growth seen in 2007.

A new Alberta Internal Load (AIL) winter peak demand of 9,710 MW was set on January 28, 2008 at hour ending (HE) 18. However, this peak was exceeded by 96 MW on December 15 when a new winter peak demand of 9,806 MW was set during HE 18. Both peaks were attributed to extreme cold temperatures throughout the province with average temperatures of -33 C and -24 C on January 28 and December 15 respectively.

A new summer peak of 9,541 MW was set on August 18, 2008 during HE 14. This is 2.4 per cent higher than the summer peak of 9,321 MW set on July 19, 2008 during HE 15.

Alberta's peak load growth continues to be stronger than overall load growth, averaging 2.2 per cent per year over the past five years, and 1.1 per cent in 2008. Summer peak load growth has proven even stronger, averaging 2.9 per cent over the past five years and 2.4 per cent in 2008. The increase in summer peak load growth is driven by population increases in southern Alberta, particularly in the Calgary region, and higher air conditioning load.

Table 4: Demand statistics – 2000 to 2008

Alberta Internal Load *(AIL)*	2000	2001	2002	2003	2004	2005	2006	2007	**2008**
Total AIL *(GWh)*	54,053	54,464	59,428	62,714	65,260	66,267	69,371	69,661	**69,947**
Average hourly load *(MW)*	6,154	6,217	6,784	7,159	7,429	7,565	7,919	7,952	**7,963**
Maximum hourly load *(MW)*	7,785	7,934	8,570	8,786	9,236	9,580	9,661	9,701	**9,806**
Minimum hourly load *(MW)*	4,999	5,030	5,309	5,658	6,017	6,104	6,351	6,440	**6,411**
Year-over-year load growth *(%)*	–	0.76	9.11	5.53	4.06	1.54	4.68	0.42	**0.41**
Year-over-year load growth *(%)* (corrected for Leap Year effect)		**1.02**			**3.77**	**1.83**			**0.14**
Load factor *(%)*	79.0	78.4	79.2	81.5	80.4	79.0	82.0	82.0	**81.2**

Note: *The load growth per cent in blue font represents the year-over-year load growth corrected for the effect of Leap Years. The correction is done due to the additional day contributing approximately 0.3 per cent of the total AIL.*

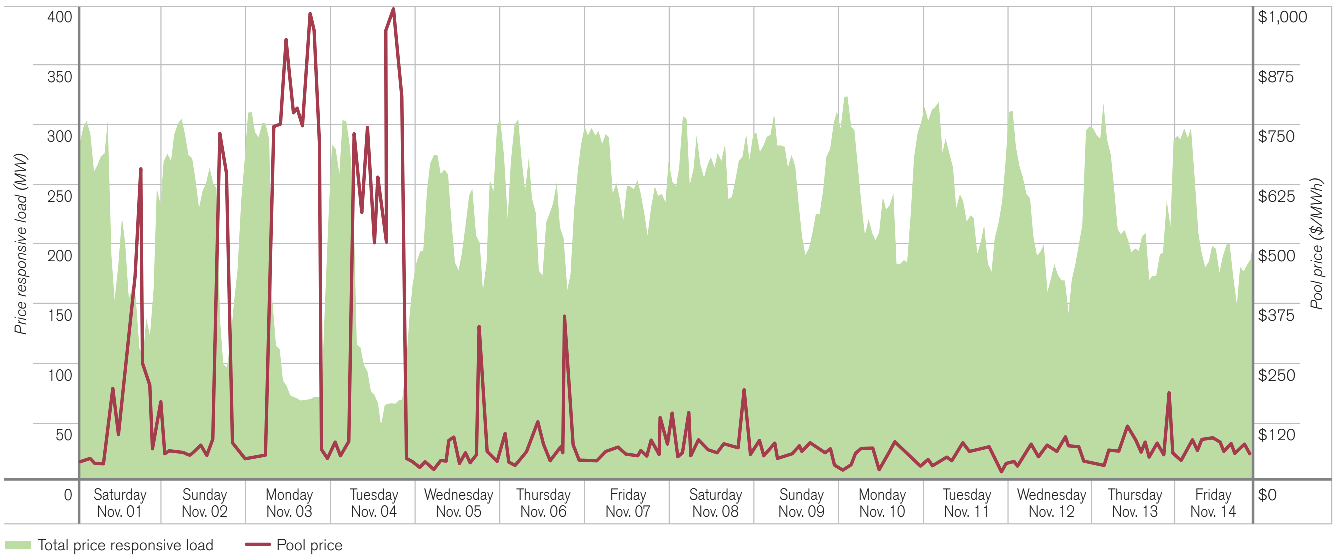
Figure 17: Annual summer and winter peaks

Demand responds to price

The AESO has a particular interest in examining how demand response programs can assist in managing reliability and contributing 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 pool price. Over the past few years, the AESO has studied a subset of these loads that regularly respond to the price. This response is voluntary, but does account for approximately 3.5 per cent of Alberta's load. Figure 18 illustrates the load responsive behaviour over a two-week period in early November 2008. During high price periods in the first four days of the month, the level of price responsive load was significantly lower. On Monday and Tuesday, the response was approximately 225 MW. This reduction results in some moderation of pool price during the highest priced hours, as these loads reduce demand when prices increase.

The AESO has formed a stakeholder working group to facilitate further development of demand response programs. The working group will develop, evaluate and make recommendations regarding demand response programs within the existing mandate of the AESO. The recommendations are intended to form the basis for broader industry consultation on the topic of demand response.

Figure 18: Price responsive load behaviour – November 1, 2008 to November 14, 2008



Stability of the merit order has improved

The energy market merit order is the list of all valid offers and bids for a settlement period. The offer and bid price blocks are sorted by price. Stability of the merit order is crucial in ensuring the AESO has the visibility and reliability of electricity generation required to operate the market effectively.

Enhanced merit order stability and visibility of supply were observed following implementation of the new maximum capability and available capability rules. This improved stability was intended as the must offer rules eliminated the ability for generating units to remove their offered megawatts from the market due to economic reasons. Under the new rules, units that only want to run during higher priced periods due to higher underlying costs must offer their energy in the merit order.

Dispatch down service

Rule changes, which created a new dispatch down service (DDS) intended to improve pool price fidelity, also involved a change to TMR energy.

TMR requires a generator to be constrained and operate at a minimum specified megawatt output level to maintain transmission system reliability. Dispatching TMR displaces in-market energy and could have an impact on pool price. To address the unintended consequences of TMR dispatches on pool price, DDS was created to establish a market for generators to offer a price to voluntarily dispatch down and offset the impact of a TMR dispatch. The DDS market was not intended to compete with the energy market.

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.

During 2008, the total payment in the DDS market was $27.5 million for 730,777 MWh of DDS dispatched. The highest monthly totals, about $4 million per month, occurred in November and December due to higher than usual TMR requirements. In November, 95,473 MWh of DDS was dispatched, while in December the total was 111,837 MWh.

During the first year of the DDS market, it has been observed that DDS has been used extensively to offset the impact of TMR dispatches on pool price, and that DDS offers have been sufficient to provide the service in nearly all hours. Figure 19 illustrates this trend over the 12 months. The DDS required calculation is TMR minus the constrained generation. In April, the constrained generation associated with the KEG conversion project was regularly greater than the TMR amount. This resulted in no requirement for DDS for more than 50 per cent of the hours in April.

Participation in the DDS market has been primarily gas and cogeneration assets. Figure 20 compares the share of DDS dispatched by fuel type.

Figure 19: Average DDS offers and DDS dispatched compared to TMR dispatches – 2008

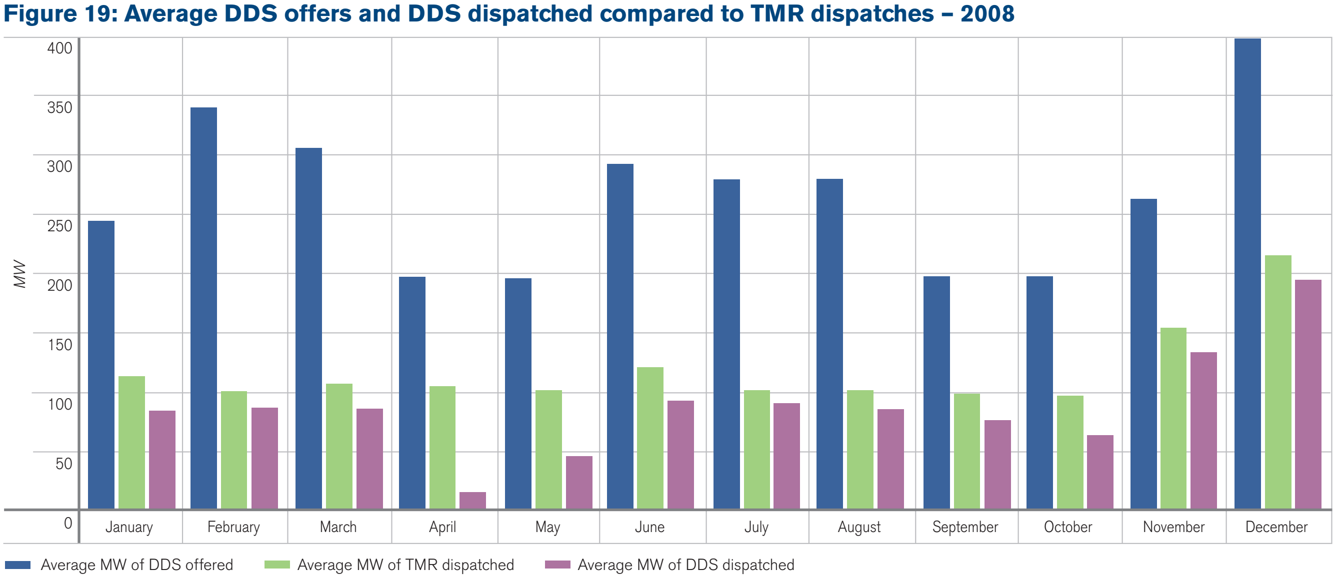
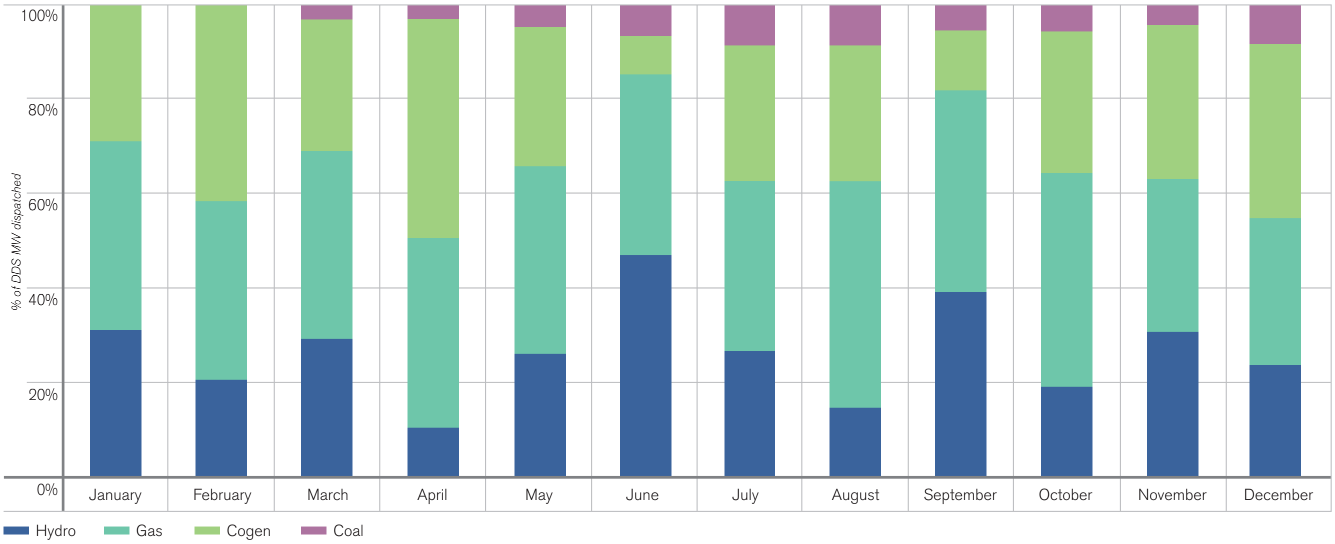


Figure 20: Per cent of DDS dispatched by fuel type – 2008

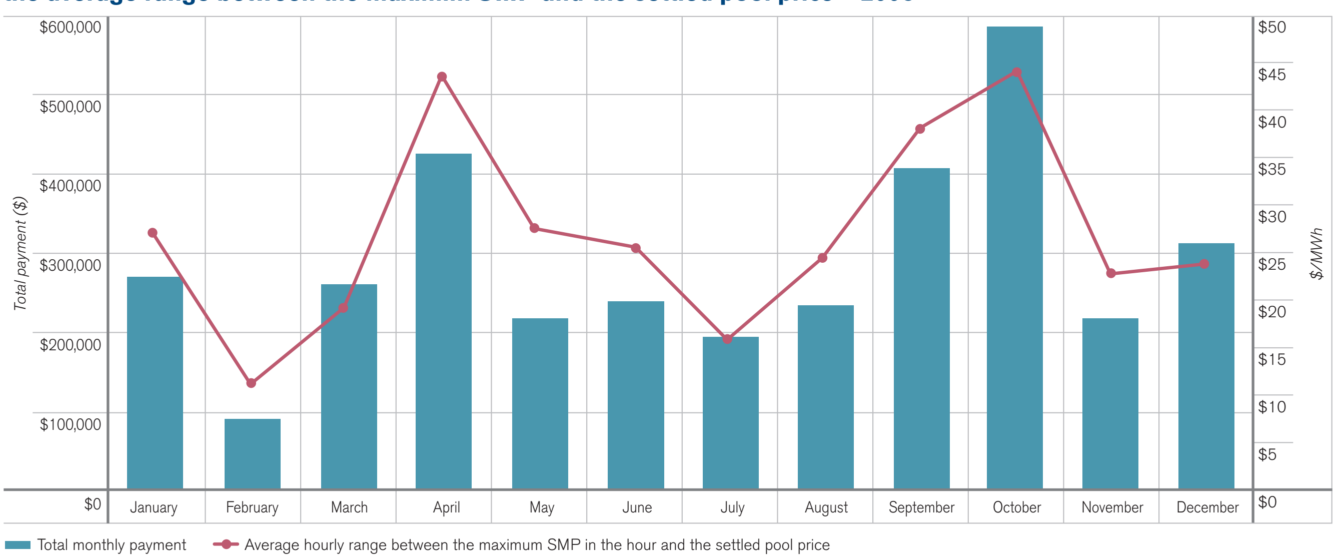


Payments to suppliers on the margin

The payments to suppliers on the margin rule allows for payments of the offer price for the energy produced during a settlement interval if the dispatch is followed. Settlement charges for these payments are applied to all load based on its proportion of total load within the settlement interval.

In 2008, the total payment made to suppliers on the margin was $3.4 million. This is less than one per cent of the total market value of the Alberta Interconnected Electric System (AIES) ($5.1 billion). Figure 21 illustrates the comparison between the maximum SMP and pool price and the total payment. The monthly total payment tracks the average range between the maximum SMP in the hour and the settled pool price.

Figure 21: Monthly total payment to suppliers on the margin compared to the average range between the maximim SMP and the settled pool price – 2008



Prices for reserves related to pool price

The AESO procures operating reserves for the AIES to ensure ongoing reliability of the transmission system. There are three types of operating reserves: regulating reserves, spinning reserves and supplemental reserves. Each type of operating reserve has two products: active and standby.

Regulating reserves are used for real-time balancing of supply and demand and require 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. Spinning reserves and supplemental reserves are both used within 10 minutes of a contingency event. Spinning reserves require synchronization to the grid. Both of these products are priced lower than regulating reserves, with spinning reserves priced slightly higher than supplemental.

Reserves are purchased from either the ancillary services exchange or through over-the-counter contracts. In 2009, the AESO is facilitating consultation to redesign the operating reserves market.

The majority of operating reserve offer prices are indexed to the pool price. During the past five years, there is a noticeable correlation between pool price and the average price paid for all three types of reserves. In 2008, pool prices increased 34 per cent over the previous year, while regulating reserve prices were 53 per cent higher and supplemental and spinning reserves prices increased 46 per cent and 47 per cent respectively. Table 5 illustrates this relationship.

Table 5: Average price/MWh

($/MWh, rounded)	2004	2005	2006	2007	**2008**
Pool price	55	70	81	67	**90**
Active regulating reserves	19	29	35	34	**52**
Active spinning reserves	13	22	30	30	**44**
Active supplemental reserves	6	15	29	26	**38**

Market share of reserves stable

Over the past five years, hydroelectric generators have consistently been the main provider of active regulating reserves due to the ability of hydro to ramp up quickly. In 2008, nearly 70 per cent of active regulating reserves were provided by hydroelectric generators, with coal-fired units and gas-fired generators providing the remainder.

In 2008, gas-fired generators provided 44 per cent of the active spinning reserves and hydro units provided 35 per cent. The majority of the remainder is provided over the intertie with B.C. As with the regulating reserves, the market share by fuel type has changed little over the past five years.

Supplemental reserves can be provided by generators, loads and the intertie. As with regulating and spinning reserves, gas-fired and hydroelectric generators provide the majority of reserves. In 2008, gas-fired generators provided 41 per cent and hydro facilities accounted for 47 per cent of the supplemental reserves.

The supplemental reserve market is the only operating reserve market in which load can participate. During 2008, load accounted for 10 per cent of the total active supplemental reserves, up from eight per cent in 2007.

Figure 22: Market share of active regulating reserves by fuel type

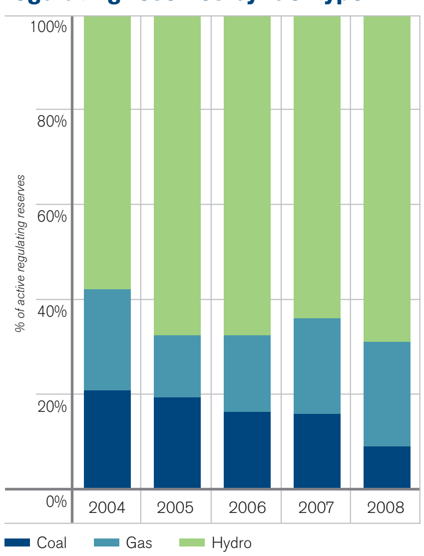


Figure 23: Market share of active spinning reserves by fuel type

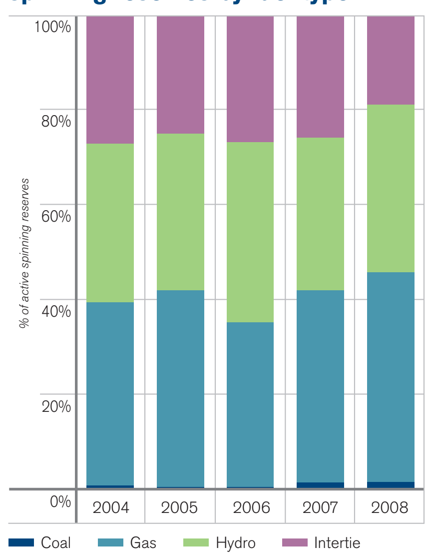
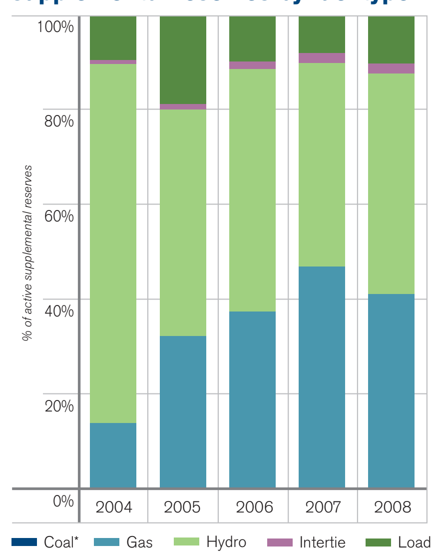


Figure 24: Market share of active supplemental reserves by fuel type



* *Coal is below one per cent in all years.*

Corporate Governance

Governance is a philosophy, an approach, and a process. The AESO Board has developed its governance structure, practices and style to ensure the needs of the organization fit within the organization's vision, mission, beliefs and values. Governance encompasses both internal and external relationships.

Fundamental to governance is the clarity it brings to decision-making, accountability and the roles of the AESO Board, executive, management and employees. The structure of the AESO provides for a strong governance model. The AESO's governance model promotes best practices, ethical behaviours, accountability, and transparency to all stakeholders (internal and external) in its business dealings.

AESO BOARD

The AESO Board is responsible for overseeing the business and affairs of the AESO. The AESO Board is actively involved with executive management in the strategic planning process and approves the strategic plan. On an ongoing basis, the AESO Board conducts financial oversight of corporate operations, including cost and risk management. How the AESO Board conducts its affairs is contained in the AESO Bylaws. A copy of the Bylaws can be found at **www.aeso.ca**

The AESO is governed by its legislative mandate and by its Board. The AESO Board is made up of members appointed by Alberta's Minister of Energy in accordance with Section 8 of the *Electric Utilities Ac*t. In accordance with the Bylaws, the AESO Board must recommend to Alberta's Minister of Energy individuals to be appointed as an AESO Board Member and may recommend to the Minister an individual to be designated as Chair. There is a maximum of nine members on the AESO Board. The AESO Board and its Committees have the authority to independently obtain and retain consultants or other advisors as deemed necessary to ensure an effective AESO Board and/or Committee.

AESO Board Members

The AESO Board Members have extensive knowledge and experience in various industries including energy, utilities and technology, as well as various professions such as regulatory, engineering and accounting. The following are current AESO Board Members:

AESO Board Member	AESO Board Member Since	Current AESO Board Position	Committee Member
Harry Hobbs	2004	Board Chair	Audit, HRCGC*
Bill Burch	2003	Vice-Chair	Chair Audit, HRCGC*
Ron George**	2003	Member	HRCGC*
Nancy Laird	2003	Member	Chair HRCGC*
Hugh Fergusson	2007	Member	HRCGC*
Robert McClinton	2007	Member	Audit
Walter Nieboer	2007	Member	Audit
Monica Sloan	2007	Member	Audit, HRCGC****
Jan Carr***	2009	Member	Audit
Gordon Ulrich***	2009	Member	Audit

* *HRCGC (Human Resources, Compensation and Governance Committee).*
** *Term as a Member expired Aug. 31, 2008.*
*** *Became a Member of the AESO Board and the Audit Committee effective Jan. 1, 2009.*
**** *Was a Member of the Audit Committee in 2008 and became a Member of the HRCGC in 2009.*

AESO BOARD COMMITTEES

The AESO Board has structured two standing committees that meet at least four times a year. Each operates in accordance with its own AESO Board-approved charter.

Audit Committee

This committee provides consultation, advice and recommendations to the AESO Board on financial reporting matters, systems of internal controls, systems for managing risk, the external audit process and the AESO's process for monitoring compliance with laws and regulations. In carrying out its mandate, the Audit Committee does so with a view to following best practices.

Human Resources, Compensation and Governance Committee (HRCGC)

This committee provides consultation, advice and recommendations to the AESO Board with respect to human resources, compensation and corporate governance matters. This includes executive compensation levels, officer selection, executive succession planning, human resources programs (including salary planning and incentive design), current human resources practices, and maintenance and enhancements to corporate governance practices.

AESO BOARD EFFECTIVENESS

AESO Board Evaluation

The AESO Board and its Committees have a self-evaluation process in place. The self-evaluation is performed on an annual basis. This evaluation is in addition to the performance management process noted on page 58.

Meeting Attendance

In 2008, the attendance of the Members at AESO Board meetings and Committee meetings was as follows:

	AESO Board	Audit	Human Resources, Compensation & Governance	Meeting Attendance	Per cent Attendance
Harry Hobbs	8 of 8	4 of 4	4 of 4	16 of 16	100
Bill Burch	8 of 8	4 of 4	4 of 4	16 of 16	100
Ron George *	3 of 4	N/A	2 of 2	5 of 6	83
Nancy Laird	8 of 8	N/A	4 of 4	12 of 12	100
Hugh Fergusson	8 of 8	N/A	4 of 4	12 of 12	100
Robert McClinton	8 of 8	4 of 4	N/A	12 of 12	100
Walter Nieboer	8 of 8	4 of 4	N/A	12 of 12	100
Monica Sloan	7 of 8	3 of 4	N/A	10 of 12	83
Attendance	58 of 60	19 of 20	18 of 18	95 of 98	N/A
% Attendance	97%	95%	100%	97%	N/A

** Term as a Member expired Aug. 31, 2008.*

AESO Compensation of Directors

A summary of Member remuneration is as follows:

Chair – base retainer	$ 90,000/year
Member – base retainer	$ 25,000/year
Vice-Chair retainer	$ 5,000/year
Committee Chair retainer	$ 5,000/year
Chair and Members, AESO Board & Committee Meetings	$ 1,000/meeting
Conducting other AESO business or affairs as required	$ 1,000/day

All reasonable expenses incurred by a Member to attend meetings or incurred by the Member in relation to AESO business or affairs are reimbursed by the AESO at cost.

The amount paid for remuneration to Members for services was $0.4 million in 2008.

Report on Executive Compensation

Compensation is designed to attract, motivate and retain AESO employees and to align with and support the AESO's values, overall business needs and human resources strategy.

The AESO's compensation policy and practices (compensation program) is competitive, reflects current market conditions, meets all legislative requirements, and exhibits fairness and equity in pay rates and salary administration.

The AESO administers the compensation program to meet the above criteria by:

- Participating in annual industry total compensation surveys.
- Comparing base pay, employee benefits and other forms of rewards and compensation with the marketplace.
- Tracking and analyzing compensation trends.
- Maintaining information on compensation categories.
- Targeting to the 50th percentile of comparable compensation survey information.
- Conducting annual reviews for all employee base pay salaries to determine appropriate salary adjustments.

The AESO's compensation program is designed to be competitive in the marketplace for comparable organizations in the energy industry. Executive compensation, including the AESO's President and Chief Executive Officer compensation, which is brought forth by the AESO Board Chair, is reviewed by the HRCGC and recommended to the AESO Board on an annual basis for approval. To perform this review, independent market information is obtained and reviewed. Each executive's salary is reviewed in the context of the individual executive's responsibilities and business performance during the year. Annual incentive payments to executive are based on organizational and individual performance.

The compensation paid (salary and incentive) to the AESO's President and Chief Executive Officer, Vice-President, Finance and the next three highest paid executives was $1.8 million in 2008. The total compensation, salary, incentive and other annual income paid to all nine AESO executives was $4.8 million in 2008. Other annual income consists of annual employer contributions to the AESO Defined Contribution Pension Plan, retiring allowances and other perquisites.

GOVERNANCE PRACTICES

The AESO looks to private, public and not-for-profit sectors of industry as a source for best business practices. The following are pertinent governance practices the AESO Board utilizes to provide sound corporate governance within the AESO.

AESO Code of Conduct Officers, Employees and Contractors

It is a policy of the AESO that all employees annually review the AESO Code of Conduct Officers, Employees and Contractors. Each of the preceding confirms compliance/non-compliance with the Code of Conduct and agrees to abide by it. New employees are required to review and agree to abide by it on their first day of employment. Each Member of the AESO Board (or members of the AESO) is bound by the AESO Members Code of Conduct outlined in the AESO Bylaws.

Strategic Planning

The AESO's strategic plan provides organizational direction for the development of corporate, departmental and individual plans and goals for the current and future years and links the organization's vision, objectives, strategies and initiatives to day-to-day operations. The strategic plan is reviewed and approved by the AESO Board. The strategic plan becomes the basis from which the annual business priorities and budgets are established.

Performance Management

The AESO establishes goals to be achieved at the corporate level. The corporate goals are developed annually by AESO management based on the business priorities set out in the strategic plan and business plan. The AESO Board provides oversight in establishing and approving the goals as well as corporate milestones and metrics. The AESO's salary administration process is designed to meet, align with and achieve the organization's performance goals.

Performance Reporting

AESO management updates the status of attaining corporate goals on a quarterly basis and reports to the AESO Board. Based on its review, management can determine which goals are on target to be met and those at risk of not being achieved. For those goals at risk of not being met, strategies are developed or altered to better achieve the desired goal.

Risk Management

The AESO is committed to proactively identifying potential risks and implementing appropriate mitigation action plans. A number of regular reports are provided to management and the AESO Board's Audit Committee that detail identified risks, their status and related mitigation strategies. The AESO prioritizes these risks and incorporates them into the annual goal-setting process. Risk mitigation includes the development and implementation of appropriate corporate policies, including various financial policies (i.e., travel policy, corporate expenses, etc.) and approval by the AESO Board. These policies are communicated to employees and are accessible by employees at all times.

Internal Controls

Internal controls have been designed and implemented by the AESO's management and are approved by the AESO Board and Audit Committee, providing reasonable assurance of achieving the following objectives:

- effectiveness and efficiency of operations
- reliability of financial reporting
- compliance with laws and regulations

External Audits, Reviews and Procedures

Operating audits, reviews and procedures are performed to determine the existence and effectiveness of internal controls as they relate to the AESO's operations and compliance with laws and regulations. This includes the annual financial statement audit performed by an independent audit firm.

AESO EXECUTIVE

The AESO Board is responsible for appointing the President and Chief Executive Officer. The President and Chief Executive Officer appoints other officers as required. Such appointments require the ratification of the AESO Board.

The organization has been structured with an executive team who run the business, including developing and implementing corporate practices. The current executive team is as follows:

David Erickson
President & Chief Executive Officer (Interim)

Cliff Monar
Senior Vice-President, Market & Regulatory Services

Sandra Scott
Senior Vice-President, Corporate Services & Chief Information Officer

Todd Fior
Vice-President, Finance

Warren Frost
Vice-President, Operations & Reliability

Heidi Kirrmaier
Vice-President, Regulatory

Neil Millar
Vice-President, Transmission

Wayne St. Amour
Vice-President, Communications & Stakeholder Relations

Board Members

Standing, left to right

Robert McClinton, Bill Burch, Gordon Ulrich, Walter Nieboer, Jan Carr, Harry Hobbs

Seated, left to right

Nancy Laird, Monica Sloan, Hugh Fergusson

Harry Hobbs
Chairman
Member of the Audit Committee and the Human Resources, Compensation and Governance Committee

Mr. Hobbs was appointed Chairman of the Board effective June 1, 2006. He has been a member of the AESO Board since May 2004. Mr. Hobbs is President of Harry Hobbs & Associates, an energy consulting firm in Calgary. He also serves as a Director of the Van Horne Institute, an organization dedicated to addressing transportation and regulatory issues in North America. Mr. Hobbs spent 25 years with Foothills Pipe Lines Ltd., serving as an executive and officer of the company before retiring in 2003. He also has served as a Board Member of numerous organizations in the private and not-for-profit sectors.

Bill Burch, FCA
Board Vice-Chair
Chair of the Audit Committee,
Member of the Human Resources, Compensation and Governance Committee

Mr. Burch has been a member of the AESO Board since 2003. He joined the Board of one of the AESO's predecessor companies in 2001. Mr. Burch is a chartered accountant with extensive background in the finance industry. Since retiring as a partner with PriceWaterhouseCoopers he has served as a Board Member for several private and public companies and is actively involved as a volunteer in his community.

Nancy Laird
Chair of the Human Resources, Compensation and Governance Committee

Ms. Laird has been a Member of the Board since June 2003. Ms. Laird has held senior executive positions in several major energy companies and has a diverse background in managing marketing and midstream, regulatory, environmental and information technology portfolios. She is a Board Member of Enerflex Systems Income Fund, Keyera Facilities Income Fund, Alter NRG Corp. and Synodon Inc. Ms. Laird is Chair of Calgary Technologies Inc. and a former Board Member of Canadian Oil Sands Trust, Alliance Pipeline, ProGas, the United Way of Calgary, Hull Child and Family Services and SAIT Polytechnic. She has an MBA from the Schulich School of Business at York University.

Hugh Fergusson
Member of the Human Resources, Compensation and Governance Committee

Mr. Fergusson has been a member of the Board since December 2007. He is currently President of Argyle Resources Inc. Mr. Fergusson has over 30 years experience in the chemical, oil and gas industries, including past Board membership of Dow Chemical Canada Inc., Union Carbide Canada Inc., the Gas Processors Association of America and the Petrochemical Feedstock Association of the Americas. He is a Director and Committee Member of Provident Energy Trust, Canexus Income Fund, AltaGas Services Inc., Beyond Compliance Inc. and the Canadian Energy Research Institute. He has been admitted to the Law Society of Upper Canada and received the designation of ICD.D from the Institute of Corporate Directors.

Monica Sloan
Member of the Audit Committee (2008),
Member of the Human Resources, Compensation and Governance Committee (2009)

Ms. Sloan joined the Board in December 2007. She was Managing Director and Chief Executive Officer of Intervera Ltd. until December 2008, and has more than 30 years of experience in the utility, energy and telecommunications industries in Alberta, including as President, Telus Advanced Communications. Ms. Sloan serves on a number of public, private and not-for-profit Boards, including Methanex Corporation and Industrial Alliance Pacific Financial Services. Past Board membership includes Echo Bay Mines, Ranger Oil and Finning International, as well as serving as past Chair of Calgary Opera.

Robert McClinton
Member of the Audit Committee

Mr. McClinton was appointed to the Board in December 2007. He has held senior executive positions in several energy companies including Canadian Turbo Inc. and BMP Energy Systems. Mr. McClinton serves as a Director on the Boards of Critical Control Solutions Inc. and CE Franklin Ltd. He also serves as Vice-Chair on the Board of the not-for-profit Calgary HandiBus Association and as Chair of its Fund Development Activities Committee. He is a member of the Alberta and Canadian Institutes of Chartered Accountants and Financial Executives International and the Institute of Corporate Directors.

Walter Nieboer
Member of the Audit Committee

Mr. Nieboer joined the Board in December 2007. He has consulted to the electric energy industry on strategic options, planning, project management and organizational effectiveness, and has appeared as an expert witness before various regulatory boards. His experience is drawn from more than 40 years in the electrical utility business in Canada and business pursuits internationally. Mr. Nieboer retired as Chief Operating Officer of TransAlta Energy Corporation in 1993. He served in various senior executive positions with TransAlta. Mr. Nieboer has served as a member of the Board of the Electricity Supply Board International, (ESBI) Alberta Ltd. and as Special Advisor to the Board of Directors of the Yukon Energy Corporation.

Jan Carr
Member of the Audit Committee

Dr. Carr has more than 35 years experience in the electricity sector as a professional engineer, and has held senior positions in the design and planning of electricity transmission and distribution systems. He has advised utilities, governments and other stakeholders on the financial, business, strategic and policy aspects of the electric power industry. Dr. Carr was Chief Executive Officer of the Ontario Power Authority from the time of its founding in January 2005 until September 2008. Prior to that, he was Vice-Chair of the Ontario Energy Board and has served on the Board of Directors of TransAlta Power and Macquarie Canadian Infrastructure Management Ltd. Dr. Carr holds a Ph.D. in Electric Power Systems from the University of Waterloo.

Gordon Ulrich
Member of the Audit Committee

Mr. Ulrich has extensive experience in both the coal and energy industries including 23 years with Luscar Ltd., where he served as President for 10 years after progressing from positions in Finance and Strategic Planning. Mr. Ulrich has served on the Boards of a number of resource companies, and for the past five years as Vice-Chair of the Balancing Pool. Mr. Ulrich is a Professional Engineer (retired), registered in the provinces of Alberta and B.C. and holds a master's degree in business administration and a bachelor's degree in geological engineering. He is a life member of the Association of Professional Engineers, Geologists, and Geophysicists of Alberta (APEGGA).

Executive Team

David Erickson
President & Chief Executive Officer (Interim)

Cliff Monar
Senior Vice-President, Market & Regulatory Services

Sandra Scott
Senior Vice-President, Corporate Services & Chief Information Officer

Todd Fior
Vice-President, Finance

Warren Frost
Vice-President, Operations & Reliability

Heidi Kirrmaier
Vice-President, Regulatory

Neil Millar
Vice-President, Transmission

Wayne St. Amour
Vice-President, Communications & Stakeholder Relations

David Erickson
President & Chief Executive Officer (Interim)

Mr. Erickson is responsible for ensuring the AESO effectively fulfils its mandate for the safe, reliable and economic operation and development of the Alberta Interconnected Electric System and operating the province's fair, efficient and openly competitive wholesale electricity market. His experience spans more than 20 years of international financial management and accounting expertise in the energy and electricity sectors. Mr. Erickson has been active in the electricity industry for many years and served as Chief Financial Officer for the former Transmission Administrator of Alberta, then began serving as Chief Financial Officer for the AESO in 2003. His responsibilities were expanded in 2005, and again in 2007 when he was appointed Senior Vice-President and Chief Operating Officer. He was appointed to his current role in December 2008.

Sandra Scott
Senior Vice-President, Corporate Services
Chief Information Officer

Ms. Scott has overall accountability for the AESO's corporate services functions including Human Resources, Communications and Stakeholder Relations, Security, Customer Services and Information Systems. Her 23-year background in the energy sector includes business leadership and operational management across a wide variety of international business units and partnership in the development of a successful western Canadian consulting organization. She has assisted a variety of companies in the areas of strategic plan development, planning and execution of business strategy, program and project management, and improved effectiveness through information technology innovation. Ms. Scott has served as Vice-President Information Technology for the AESO since July 2006 and was appointed to her current role in January 2009. She holds a Bachelor of Science degree with a major in geology from the University of Calgary.

Todd Fior
Vice-President, Finance

Mr. Fior is responsible for all financial management and accounting activities at the AESO. He has more than 18 years of public and private sector experience in the accounting, financial and treasury management areas and was most recently Director, Risk and Settlement for the AESO. Mr. Fior was appointed to his current role in February 2007.

Warren Frost
Vice-President, Operations & Reliability

Mr. Frost is responsible for Electric System Operations at the AESO, which includes overseeing the creation of operating limits and standards, operating and contingency plans and the operation of the AESO's System Coordination Centre to ensure the safe, reliable and economic operation of Alberta's interconnected power system and electricity markets. Mr. Frost is an electrical engineer with more than 32 years experience in the electricity industry including policy development, system operations, transmission asset management, regulatory and customer services. Mr. Frost was appointed to his current role in July 2005.

Heidi Kirrmaier
Vice-President, Regulatory

Ms. Kirrmaier is accountable for regulatory affairs at the AESO, focusing on the rules approval process and system access service tariff as regulated by the Alberta Utilities Commission. She also oversees the AESO's compliance monitoring activities. Ms. Kirrmaier brings extensive regulatory experience to her current role including previous responsibilities with ATCO, Aquila Networks Canada and the British Columbia Utilities Commission. Ms. Kirrmaier is a Professional Engineer in the province of Alberta, and was appointed to her current role in December 2005.

Neil Millar
Vice-President, Transmission

Mr. Millar is accountable for the planning and timely development of Alberta's interconnected electric grid, including the development of the organization's Long-term Transmission System Plan and individual Needs Identification Documents to reinforce the provincial transmission system. He has over 25 years of industry experience in a number of transmission planning, regulatory and customer services roles. Prior to accepting his current role, Mr. Millar was Director of Regulatory Affairs with the AESO, a position he held since 2003. Mr. Millar was appointed to his current role in April 2004.

Cliff Monar
Senior Vice-President,
Market & Regulatory Services

Mr. Monar has overall accountability for market and regulatory services including electricity and operating reserve market design, development of market rules and operating policies, design and implementation of the AESO tariff, compliance monitoring and commercial services (ancillary services procurement). Mr. Monar has over 20 years of industry experience in energy trading and portfolio management, business development, engineering and project management. In 2007, he was appointed Vice-President of Market Services and prior to that, he was Director of Strategic Initiatives and Director of Commercial Services for the AESO. Mr. Monar was appointed to his current role in January 2009.

Wayne St. Amour
Vice-President, Communications
& Stakeholder Relations

Dr. St. Amour (Ph.D.) is responsible for the strategic direction of the AESO's Stakeholder Relations and Corporate Communications functions. He has more than 25 years of senior-level experience in strategic management, human resources, corporate communications, marketing and public consultation. He has worked in the mining and electricity industries and has consulted to various energy sector organizations on strategy and sustainable development initiatives in Canada, the U.S. and the U.K. Dr. St. Amour was appointed to the executive of the AESO in October 2006.

Management's Discussion and Analysis

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This management's discussion and analysis of financial condition and results of operations (MD&A) should be read in conjunction with the Alberta Electric System Operator's (AESO) audited financial statements for the years ended December 31, 2008 and 2007 and accompanying notes. The MD&A and financial statements are reviewed and approved by the AESO Board. The AESO's financial statements have been prepared in accordance with Canadian generally accepted accounting principles (GAAP) and are expressed in Canadian dollars.

MD&A

The AESO is responsible for the operation of Alberta's competitive power pool; determining the order of dispatch of electric energy and ancillary services; providing system access service on the electric transmission grid; directing the safe, reliable and economic operation of the interconnected electric system; planning the capability of the transmission system to meet future needs; and administering load settlement.

1. SUMMARY ANNUAL HIGHLIGHTS

The AESO, a not-for-profit statutory corporation, recovers its operating and capital costs through three separate revenue sources, each of which is designed to recover the costs directly related to the provision of a specific service, as well as a portion of the shared corporate services costs. The overall revenues and costs of the AESO are as follows:

(Millions) Years ended December 31	**2008**	2007	Variance	% Variance
Transmission revenue	**$ 1,091.6**	$ 905.1	$ 186.5	21
Energy market charge	**22.3**	13.7	8.6	63
Load settlement	**3.6**	5.1	(1.5)	(29)
Interest and other income	**2.9**	5.3	(2.4)	(45)
Wire costs	**$ 499.0**	$ 441.2	$ 57.8	13
Ancillary services	**311.9**	235.8	76.1	32
Line losses	**220.6**	183.8	36.8	20
General and administrative	**62.9**	52.2	10.7	20
Amortization	**7.8**	9.2	(1.4)	(15)
Other industry costs	**16.7**	4.8	11.9	248
Interest expense	**1.4**	2.2	(0.8)	(36)

2. REVENUE

The *Electric Utilities Act (EUA)* requires that the AESO operates so that no profit or loss results on an annual basis from its operations. To achieve this, revenue is recognized to the extent of annual operating costs, including the amortization of capital assets. When the annual sum of collections differs from the annual operating costs, the difference is recorded as revenue or deferred revenue and recognized in the deferral accounts. The AESO's three revenue sources are transmission, energy market and load settlement.

Transmission

Revenue Summary

(Millions) Years ended December 31	**2008**	2007	Variance	% Variance
Transmission revenue	**$ 1,091.6**	$ 905.1	$ 186.5	21
Interest and other revenue	**2.5**	4.9	(2.4)	(49)
Total transmission revenue	**$ 1,094.1**	$ 910.0	$ 184.1	20

The AESO is responsible for paying all of the costs of managing the provincial transmission system and recovering the costs through a tariff approved by the Alberta Utilities Commission (AUC), and prior to January 1, 2008, the Alberta Energy and Utilities Board (EUB). The tariff is designed to allocate the costs to all users of the transmission system based on their level of usage.

On a monthly basis, the AESO invoices its transmission customers for transmission system access services based on approved tariff rates. The AESO also pays for costs associated with providing system access services. The monthly differences in the revenues collected and the costs incurred are accumulated in the AESO's transmission deferral account and can be attributed to several factors:

- Timing of revenues and costs (monthly fluctuations);
- Forecast variances (pool price volatility, meter volumes and regulatory decisions); and
- Any misalignment of approved rates and the current year revenue requirement (delays in having the current year rates approved).

In circumstances where collections are in excess of the transmission costs, the excess amount is recognized in the deferral accounts and refunded to customers in future periods. In circumstances where collections are less than the transmission costs, the shortfall is recorded as revenue, recognized in the deferral accounts and recovered from transmission customers in future periods.

As part of the transmission tariff, Deferral Account Adjustment Rider C is intended to bring the transmission deferral account balance for non-transmission line loss rate categories to zero during the following calendar quarter. It is a dollar per megawatt hour collection or payment by rate class and rate component. Losses Calibration Factor Rider E is intended to bring the transmission line loss deferral account balance to zero during the remainder of the calendar year. Rate Rider E is a percentage adjustment to all location-specific loss factors.

For non-transmission line loss rate categories, the AESO files a retrospective deferral account reconciliation application with the AUC for approval of the final settlement amounts. The final reconciliation process associates all revenue and cost adjustments by rate category to the appropriate production month and allocates the corresponding charges and refunds to transmission customers. For transmission line losses, Rate Rider E is a prospective adjustment for the reconciliation of deferral account balances.

The interest and other revenue in 2008 of $2.5 million primarily relates to interest earned on transmission customer contributions.

Deferral Summary

(Millions) Years ended December 31	**2008**	2007
Collections	**$ 1,083.8**	$ 956.4
Costs	**1,094.1**	910.0
Transmission (revenue) deferred revenue	**(10.3)**	46.4
Deferral account payable, beginning of year	**50.7**	4.3
Interim disbursement of the 2004-2007 Deferral Account Reconciliation Application	**(51.1)**	–
Deferral account (receivable) payable, end of year	**$ (10.7)**	$ 50.7

On an annual basis, transmission collections are dependent upon approved transmission tariff rates, pool price and volumes of energy transmitted. Transmission costs are discussed in the following section.

The transmission deferral account balance changed from a payable to transmission customers of $50.7 million at the end of 2007 to a receivable from transmission customers of $10.7 million at December 31, 2008. This change is due to the combination of the 2008 transmission collections being $10.3 million less than transmission costs and $51.1 million in payments made to transmission customers in 2008 for the interim settlement of the 2004-2007 Deferral Account Reconciliation Application.

The transmission deferral balance of $10.7 million at December 31, 2008 is comprised of the following four components:

- The variance in revenues collected and costs incurred of $2.6 million resulting in a receivable for transmission line losses from 2006 and subsequent years.
- The net revenue and cost adjustments of $2.2 million resulting in a receivable from transmission customers related to production years prior to 2008, which have accumulated since the AESO compiled the 2004-2007 deferral account reconciliation in early 2008.
- The variance in revenues collected and costs incurred in 2008 for the current year production have contributed to a transmission deferral account balance of $4.9 million receivable.
- The transmission customer receivable of $1.0 million is the deferred rent related to the amortization of a 10-month, rent-free period on the AESO's current office lease. This amortization of rent is not incorporated into the AESO's annual revenue requirement; it includes only the cash payments.

Energy Market

Revenue Summary

(Millions) Years ended December 31	**2008**	2007	Variance	% Variance
Energy market revenue	**$ 22.3**	$ 13.7	$ 8.6	63
Interest and other revenue	**0.3**	0.3	0.0	0
Total energy market revenue	**$ 22.6**	$ 14.0	$ 8.6	61

The AESO recovers the costs of operating the real-time energy market through an energy market trading charge on all megawatt hours traded. The energy market trading charge is set to recover the operating costs and the amortization of capital assets during that period.

In circumstances where annual collections are in excess of energy market costs, the excess amount is recognized in the deferral accounts and incorporated into a reduction in the following year's required energy market trading charge. In circumstances where annual collections are less than the energy market costs, the shortfall is recorded as revenue, recognized in the deferral accounts and collected in the following year.

The energy market deferral amount is comprised of two components:

- The accumulated difference between revenues collected and costs paid that is receivable from, or payable to, energy market participants; and
- The unamortized portion of the AESO's system controller capital assets that were recovered from transmission customers in prior years by the Transmission Administrator of Alberta Ltd. (TA). The revenue associated with the system controller capital assets was recognized by the AESO over the useful life of the assets. These assets were fully amortized in 2007.

Energy market collections are dependent on the annual energy market trading charge and the volume of energy traded through the power pool. For five consecutive years, since 2004, the energy market trading charge has been 11.1 cents per megawatt hour traded.

Deferral Summary

(Millions) Years ended December 31	**2008**	2007
Collections	**$ 13.5**	$ 13.7
Costs	**22.6**	14.0
Energy market revenue	**(9.1)**	(0.3)
Deferral account payable, beginning of year	**6.3**	6.6
Deferral account (receivable) payable, end of year	**$ (2.8)**	$ 6.3

The energy market deferral amount at December 31, 2008 is a $2.8 million receivable compared to a $6.3 million payable at the end of 2007. The change of $9.1 million during 2008 is the result of:

- Costs of $5.2 million for the energy market portion of the AUC administrative fees, which were not incorporated into the 2008 energy market trading charge. Under the provision of the *Alberta Utilities Commission Act* (effective January 1, 2008), AUC operating and capital costs are recovered from natural gas and electricity market participants under its jurisdiction or any person to whom the AUC provides services. Accordingly, the AUC apportions all of its costs related to its wholesale electric market activities to the AESO as an AUC administration fee.
- Costs related to general and administrative, amortization and interest exceeding collections by $3.9 million.

A portion of the energy market charge collected by the AESO is remitted to the Market Surveillance Administrator (MSA) for its revenue requirement in accordance with the *EUA*. The AESO facilitates the cash collection process for the funding of the MSA through a per megawatt hour addition to the AESO's energy market trading charge. In 2008, the MSA's portion of the total energy market trading charge of 14.1 cents per megawatt hour is 3.0 cents per megawatt hour, with the remaining 11.1 cents per megawatt hour for the AESO's operations. This compares to a MSA charge of 2.5 cents per megawatt hour in 2007.

The MSA's revenue and costs are separate and independent of the AESO's financial records. The AESO records the difference between the payments made to the MSA and the collection on behalf of the MSA as a separate deferral account. At December 31, 2008 and 2007, the difference between MSA collections and payments is less than $0.2 million.

Load Settlement

Revenue Summary

(Millions) Years ended December 31	**2008**	2007	Variance	% Variance
Load settlement recovery	**$ 3.6**	$ 5.1	$ (1.5)	(29)
Interest and other revenue	**0.0**	0.0	0.0	–
Total load settlement revenue	**$ 3.6**	$ 5.1	$ (1.5)	(29)

The expenses that are incurred by the AESO to provide services related to administering, and prior to January 1, 2008 administering and regulating provincial load settlement, are charged to the owners of electric distribution systems and wire service providers conducting load settlement under the AESO's Independent System Operator (ISO) rules. The costs associated with load settlement include direct function costs, an allocation of the AESO's corporate shared services and an allocation of amortization for the recovery of capital assets.

The difference in the annual revenue collections and costs incurred associated with load settlement is recorded in the deferral accounts. On an annual basis, the load settlement deferral amount is charged or refunded to the owners of electric distribution systems and wire service providers.

Deferral Summary

(Millions) Years ended December 31	**2008**	2007
Collections	**$ 4.4**	$ 5.4
Costs	**3.6**	5.2
Load settlement deferred revenue	**0.8**	0.2
Deferral account payable, beginning of year	**1.0**	0.8
Deferral account payable, end of year	**$ 1.8**	$ 1.0

Load settlement collections are dependent upon the AESO's annual forecast of load settlement costs.

3. OPERATING COSTS

Transmission System Costs

The following information provides the costs of managing the transmission system. These amounts represent the recording of the financial transactions that occurred in the reporting periods in accordance with Canadian GAAP. This differs from the production period reporting in the AESO's General Tariff Applications.

(Millions) Years ended December 31	**2008**	2007	Variance	% Variance
Wires costs	**$ 499.0**	$ 441.2	$ 57.8	13
Ancillary services costs	**$ 311.9**	$ 235.8	$ 76.1	32
Line losses	**$ 220.6**	$ 183.8	$ 36.8	20

Wires Costs

Wires costs represent the amount paid to the owners of the transmission facilities in accordance with their AUC-approved tariffs and are not controllable costs of the AESO. The costs increased $57.8 million or 13 per cent compared to 2007 due to changes in the regulated rates charged by the transmission facility owners.

Ancillary Services

Ancillary services are procured by the AESO to ensure ongoing reliability of the transmission system through contracts, which include exchange-traded or over-the-counter contracts, generation capacity and load reduction capabilities, as well as contracts that are entered by way of competitive processes. The AESO has entered into various contracts for ancillary services that include operating reserves, transmission must-run (TMR), under-frequency mitigation and system restoration.

The cost of ancillary services increased to $311.9 million in 2008 compared to $235.8 million in 2007, an increase of $76.1 million or 32 per cent. This increase is mainly due to the increase in costs associated with operating reserves, which are offset by a decrease in costs for TMR services as described below.

Operating Reserves are comprised of three types of active reserves, with the minimum levels of operating reserves based on standards established by the Western Electricity Coordinating Council (WECC):

- **Regulating reserves –** The provision of generation and load response capability, including capacity, energy and maneuverability, which respond to the AESO's automatic generation control (AGC) system.

- **Spinning reserves –** Unloaded generation that is synchronized to the system, automatically responsive to frequency deviation and ready to serve additional demand following an AESO system controller directive. A customer offering spinning reserves must be able to ramp up their generator within 10 minutes in response to a system controller directive due to a system contingency.

- **Supplemental reserves –** Similar to spinning reserves except supplemental reserves are not required to respond to frequency deviations; therefore, they include load and generators.

Operating reserves are purchased from the ancillary services exchange and through over-the-counter contracts. All providers of operating reserves traded on the exchange are paid the market clearing price whereas all providers who sell volumes over-the-counter are paid their offer price. In exchange for this payment, the AESO obtains the right to utilize the provider's energy and/or capacity as reserves. The majority of operating reserve offer prices are indexed to the pool price.

Operating reserves costs increased to $262.1 million in 2008 compared to $180.7 million in 2007, an increase of $81.4 million or 45 per cent. With comparable volumes in 2008 and 2007, the increase is attributable to higher pool prices at various times during 2008 resulting from unplanned generation and transmission outages that caused significant increases to the cost of operating reserves during these periods.

Transmission Must-Run is generation required to be online and running at specific generation levels in certain parts of the Alberta Interconnected Electric System (AIES) to ensure system reliability. This service is typically procured through commercial contracts between the AESO and suppliers.

The costs of TMR are dependent upon numerous variables including, but not limited to, market heat rates and gas prices. The market heat rate is the pool price divided by the gas price. As the market heat rate increases, representing a divergence of pool price and gas price, the cost of TMR contracts will decrease, though not proportionately.

TMR costs decreased to $41.8 million in 2008 compared to $45.6 million in 2007, a decrease of $3.8 million or eight per cent. As previously mentioned, market heat rates and gas prices are the most significant factors contributing to changes in TMR costs. In 2008, the average market heat rate and the average gas price increased six per cent and 27 per cent respectively (12.16 in 2008 from 11.45 in 2007 and $7.73 per gigajoule in 2008 from $6.10 in 2007), which resulted in a decrease to TMR costs.

Line Losses

Line losses represent the amount of energy that is 'lost' as a result of electrical resistance on the transmission lines. The volumes associated with line losses are determined through the energy market settlement as the difference between the generation and import volumes less consumption and export volumes. The hourly volumes of line losses vary based on load and export levels, generation (baseload, peaking units and import) available to serve load, weather conditions, and changes in the transmission topology. System maintenance schedules, unexpected failures, dispatch decisions on the AIES, and short-term system measures (such as demand response) may also affect the volume of losses. The value of line losses is calculated at the hourly pool price.

The cost of line losses in 2008 is $220.6 million compared to $183.8 million in 2007, an increase of $36.8 million or 20 per cent. The volumes of line losses remain relatively consistent between 2008 and 2007 at approximately 2.65 and 2.87 terawatt hours respectively.

The average hourly pool price, at which losses are valued, increased by 34 per cent from 2007 causing line loss costs to increase by 20 per cent. The average hourly pool price in 2008 is $90 per megawatt hour compared to $67 per megawatt hour in 2007.

Other Industry Costs

Other industry costs represent certain costs the AESO funds on behalf of industry participants, including the costs of stakeholder participation in the AESO's regulatory proceedings, the cost of membership in the WECC and an allocation for AUC-related costs.

(Millions) Years ended December 31	**2008**	2007	Variance	% Variance
Transmission	**$ 11.5**	$ 4.8	$ 6.7	140
Energy market	**5.2**	0.0	5.2	100
Total other industry	**$ 16.7**	$ 4.8	$ 11.9	248

Other industry costs increased in 2008 by $11.9 million or 248 per cent from $4.8 million in 2007 to $16.7 million in 2008. This increase is primarily the result of an increase in AUC administrative fees in 2008 of $13.8 million compared to $2.3 million in EUB costs in 2007, an increase of $11.5 million or 500 per cent. Under the provision of the *Alberta Utilities Commission Act (AUC Act)* (effective January 1, 2008), AUC operating and capital costs are recovered from natural gas and electricity market participants under its jurisdiction or any person to whom the AUC provides services. Accordingly, the AUC apportions its costs related to its electricity transmission and wholesale electric market activities to the AESO as an AUC administration fee.

General and Administrative Costs

The following table presents the general and administrative costs for the AESO:

(Millions) Years ended December 31	**2008**	2007	Variance	% Variance
Salaries and benefits	**$ 37.4**	$ 32.3	$ 5.1	16
Professional fees and consulting	**12.6**	9.7	2.9	30
Office and administrative	**12.9**	10.2	2.7	26
Total administrative	**62.9**	52.2	10.7	20
Amortization	**7.8**	9.2	(1.4)	(15)
Interest	**1.4**	2.2	(0.8)	(36)
Total general and administrative costs	**$ 72.1**	$ 63.6	$ 8.5	13

Salaries and Benefits

The increase is due to a full year of salary and benefits for staff hired in 2007 (23 position additions), additional staff hired during 2008 (26 position additions) and annual compensation adjustments for staff. Additional costs incurred in 2008 relate to a retirement allowance for an executive member.

Professional Fees and Consulting

The increase in professional fees and consulting in 2008 relates to additional resources to supplement staff to address new business initiatives and provide technical expertise. The focus for consulting services in 2008 was on projects such as the preparation of wind generation interconnection proposals, modifications to the system restoration training simulator and maintenance of the transmission deferral account reporting system. Additional cost increases are a result of using consulting services for the business process and pre-development phases of future capital projects including the dispatch tool architecture project. In 2008, the AESO utilized contracted services for certain corporate information technology (IT) support.

Office and Administrative

The most notable increase relates to the advertising, printing, mailouts and travel for the AESO's participation in a more comprehensive public education and outreach program. Additional cost increases are associated with acquiring additional space at the secondary data centre, higher operating costs for office facilities and additional training for IT staff on new software.

Amortization

Amortization of capital assets in 2008 includes the full year of amortization for the 2007 additions, new additions in 2008 offset by a reduction in amortization for assets that became fully amortized. Capital expenditures in 2008 are $20.4 million, of which $12.2 million are work in progress assets that are not yet subject to amortization. Offsetting the increase to amortization related to the new capital additions are the completion of the amortization of the Energy Trading System (ETS) in 2007 (a reduction of $1.6 million in annual amortization) and an increase in the estimated useful life of the software program that is used primarily to support the load settlement function (a reduction of $1.1 million in amortization in 2008).

Interest

Interest expense is incurred as a result of the bank debt held throughout the year and the associated borrowing rate. Interest costs are incurred to fund capital purchases and working capital due to the timing differences in the collection of revenues and the payment of expenses. The reduction to interest costs in 2008 is due to the reduced borrowing rates and surplus transmission deferral account balances prior to the payment of $51.1 million for the interim settlement of the 2004-2007 Deferral Account Reconciliation Application in July 2008. As this transmission deferral surplus accumulated since 2004, these funds have been used to offset otherwise required debt balances to fund capital purchases and working capital. In the absence of holding these funds, the interest costs would have been $2.7 million in 2008 and $3.6 million in 2007.

4. FUNCTIONAL COST DETAIL

The AESO is organized to integrate the functions of transmission, energy market and load settlement to maximize the benefits under the *EUA*. This integration results in cost allocations in many parts of the organization for the purpose of cost recovery. Management views the operations as one fully integrated operation. In determining the revenue requirement on a function-by-function basis, all AESO costs are assigned or allocated to one of the three functions.

	General and Administrative		Amortization		Interest		Total	
(Millions) Years ended December 31	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007
Transmission	**$ 45.9**	$ 39.1	**$ 4.4**	$ 3.9	**$ 0.8**	$ 1.5	**$ 51.1**	$ 44.5
Energy market	**15.0**	10.6	**2.0**	3.1	**0.4**	0.3	**17.4**	14.0
Load settlement	**2.0**	2.5	**1.4**	2.2	**0.2**	0.4	**3.6**	5.1
Total	**$ 62.9**	$ 52.2	**$ 7.8**	$ 9.2	**$ 1.4**	$ 2.2	**$ 72.1**	$ 63.6

General and Administrative

The percentage allocation of general and administrative costs by function required adjustments in 2008 to reflect changing operational activities. The most significant change in the allocation of costs occurred in the IT area with additional system maintenance and support costs being associated with energy market systems in 2008. With general and administrative costs increasing in the departments directly associated with the transmission and energy market functions in 2008, a higher percentage of the corporate service costs have been allocated to these functions and a lower percentage allocated to the load settlement function.

Amortization

While the allocation of amortization to the transmission function remained constant with 2007, notable changes occurred for the energy market and load settlement functions. In 2007, the ETS was fully amortized, which had been allocated entirely to the energy market function, thus reducing amortization in 2008. The reduction in the 2008 load settlement amortization is primarily the result of the AESO's assessment that the useful life of the software program that is used primarily to support the load settlement function has been extended for additional years.

Interest

By utilizing the surplus transmission deferral balances prior to the settlement with transmission customers in the third quarter of 2008, the AESO was able to reduce required debt borrowings in both 2008 and 2007. An imputed interest income amount of $1.3 million for 2008 is payable to transmission customers related to the use of the funds and is recorded as a reduction to the transmission function interest costs.

Independent of this, the required debt financing requirements increased in 2008 for funding of the increase in the net book value of capital assets and as a result of the reduction of the energy market deferral surplus. The energy market function was allocated a higher proportion of the interest costs in 2008 as a result of an increase to its capital asset balance and the reduction of the energy market deferral surplus. The allocation of interest costs to the load settlement function decreased as a result of a decrease in its capital asset balance.

5. FINANCIAL POSITION AND LIQUIDITY

(Millions) Year ended December 31	**2008**
Cash, beginning of year	**$ 61.7**
Operating activities	**(14.7)**
Investing activities	**(20.4)**
Financing activities	**(13.8)**
Cash, end of year	**$ 12.8**

The cash balance as at December 31, 2008 is $12.8 million compared to $61.7 million at December 31, 2007. The decrease is primarily the result of the following:

- **Operating activities** used cash of $14.7 million in 2008. The decrease is mainly attributed to a change in non-cash working capital of $22.5 million. The accounts receivable and accounts payable balances at December 31, 2008 relate to the December production month whereas the balances at December 31, 2007 relate to both November and December production months. The November settlement in 2007 occurred on the first business day in January due to the number of business days in December.
  - Accounts receivable balance at December 31, 2008 is $122.3 million compared to $182.6 million at December 31, 2007, a decrease of $60.3 million. The decrease is primarily the result of the collection of the November 2008 transmission and energy market receivables in December whereas in 2007 the November 2007 receivables were carried forward into the new year in accordance with the pre-defined settlement cycle.
  - Accounts payable balance at December 31, 2008 is $114.7 million compared to $192.9 million at December 31, 2007, a decrease of $78.2 million. The decrease is primarily the result of the payment of the November 2008 transmission and energy market payables in December whereas in 2007 the November 2007 payables were carried forward into the new year in accordance with the pre-defined settlement cycle.
- **Investing activities** used cash of $20.4 million for capital asset additions.
- **Financing activities** used cash of $13.8 million in 2008. The primary financing activities are a decrease in deferral account payable to customers of $69.7 million offset by an increase in bank debt of $55.9 million.

As at December 31, 2008, the AESO had the following credit facilities available to fund general operating and capital activities:

(Millions) Year ended December 31, 2008	**Total**	Available	Used
Term revolving facility	**$ 70.0**	$ 18.4	$ 51.6
Demand revolving facility	**$ 70.0**	$ 20.0	$ 50.0
Demand treasury risk management facility	**$ 9.0**	$ 9.0	$ –

The term revolving facility includes a $10 million letter of credit at December 31, 2008, which is issued as security for the AESO's procurement of operating reserves.

6. OUTLOOK

Cost recovery for the operations of the AESO is approved on an annual basis by the AESO Board, and for transmission-related activities, subsequently by the AUC.

For transmission-related activities in 2009, the AESO established a revenue requirement of $607.7 million through the 2009 Budget Review Process for costs related to ancillary services, line losses, other industry and general and administrative costs. A revenue requirement of $486.3 million for wires costs results from approvals by the AUC for transmission facility owner tariffs. The total transmission revenue requirement in 2009 of $1,094.0 million remains consistent with the actual costs in 2008 of $1,094.1 million.

For energy market activities, the annual costs are forecast to increase to $26.4 million in 2009 from 2008 actual costs of $22.6 million, a $3.7 million or 16 per cent increase. This forecast increase is primarily the result of the energy market portion of the AUC administrative fees for the AUC's wholesale electric market activities, which are forecast to be $7.2 million in 2009 ($5.2 million in 2008). With the combination of this forecast cost increase and the 2008 deferral balance, the AESO's portion of the 2009 energy market trading charge will increase to 23.2 cents per megawatt hour in 2009 compared to 11.1 cents per megawatt hour in 2008, an increase of 12.1 cents per megawatt hour or 109 per cent. In 2009, the total energy market trading charge, which also includes a MSA component, will be 25.7 cents per megawatt hour, a change from the 2008 charge of 14.1 cents per megawatt hour.

The industrial and residential growth in the province of Alberta over the past decade has gradually absorbed the excess capacity of the provincial transmission system. In response to the growing demand for electricity and the need for transmission system reinforcement, both industry and the government have begun to make changes to the electricity landscape in the province. Over the last several years, the province has seen a growing number of suppliers interested in connecting to the Alberta power grid such as new or upgraded coal and gas units, new cogeneration facilities and wind power. With the current economic downturn, the AESO is focused on assessing the impact of these economic conditions on industry operations to ensure the AESO is positioned to respond to any changes in industry direction while ensuring reliable system operations.

In December 2008, the Department of Energy published a new Provincial Energy Strategy *Launching Alberta's Energy Future*. The energy strategy is a significant and relevant policy direction to be considered in planning the energy future of Albertans. It states that ". . . Transmission infrastructure is a public good that must be available in advance of need, enable addition of new generation and be capable of meeting long-term load growth throughout the province". The energy strategy outlines the steps required to strengthen the provincial transmission system. These include leading the ". . . development of a plan for a comprehensive upgrade to the transmission system in Alberta" . . . and the need to "review and streamline the regulatory process for transmission siting". The AESO will work closely with the Department of Energy to implement those aspects of the energy strategy relevant to its mandate and to ensure that its business priorities remain aligned with the energy strategy.

The AESO, in support of the energy-only market design in Alberta, is focusing on the development and implementation of enhancements to the market rules to ensure the sustainability of an energy-only market. Over the last year, and continuing on through the next several years, the AESO is focusing on market initiatives such as long-term adequacy, congestion management, generation outage coordination, reliability unit commitment, wind management, demand response, dispatchable interties and the operating reserve market redesign. Many of these projects will require a capital investment for computer systems and applications.

In response to the increasingly complex operational requirements, security for the operations of the AIES and the age of the existing system, a replacement of the Energy Management System (EMS) began in 2007 with staged commissioning to begin in October 2009 and completion targeted for mid-2010. As part of this initiative, a new Enterprise Service Bus (ESB) technology will be implemented that will enhance the flexibility and integration of EMS with other AESO IT operating systems to ensure redundancy and high availability exists to support the system controllers to supervise and direct the operations of the power system.

In April 2007, the AESO brought to the attention of the MSA certain ancillary services transactions that did not comply with the AESO's business practices. In May 2007, the MSA initiated a review into the activities in the ancillary services market and in November 2008 issued its "MSA Report, Ancillary Services Investigation". In this report, the MSA noted that it ". . . did not find any evidence of intent by the AESO or counterparties to manipulate market prices" nor did it find ". . . any evidence of a distortion of market prices". As a result, the MSA was not taking any direct enforcement action and had concluded its investigation. However, as certain trades may have been contrary to the ancillary services exchange trade agreement to which the AESO is a party, the MSA referred the matter to the exchange operator (Alberta Watt Exchange Limited) and the Alberta Securities Commission.

In February 2008, the Canadian Accounting Standards Board (AcSB) confirmed that effective January 1, 2011, Canadian GAAP for publicly accountable entities will be replaced in full with International Financial Reporting Standards (IFRS) as promulgated by the International AcSB. While the requirement for the new accounting standards does not include not-for-profit entities such as the AESO, management's current intentions are to transition to IFRS on the same timeline as publicly accountable entities. Management is currently assessing the impact of adopting IFRS and is developing a plan to achieve convergence to IFRS by January 1, 2011. Based on management's initial assessments, the AESO has identified that the accounting and disclosure of rate regulated assets and liabilities and property, plant and equipment are the areas that have the greatest potential impact upon conversion.

7. RISK MANAGEMENT

Similar to other electric system operators and wholesale market facilitators, the AESO is exposed to various risks and uncertainties in the normal course of business. The risk management processes developed by the AESO are designed to identify the risks confronting the AESO, assessing the impact and likelihood of those risks occurring, and determining mitigation strategies to be taken. Regular reports are provided to senior management, the Audit Committee and the AESO Board detailing the status of the risks identified and the related mitigation strategies. The AESO prioritizes the risks identified and incorporates this information into the organization's corporate strategies and annual goals and objectives.

While many of the risks identified by the AESO's risk management processes are not directly within the control of the AESO, it has adopted several strategies to reduce and mitigate the effects of those risks that are within its control. The key features of the AESO's internal control environment that facilitate the AESO's risk management processes are as follows:

- The AESO is governed by a Board that is appointed by the Alberta Minister of Energy and is independent from any person or entity having a material interest in the electricity industry.

- Corporate policies are developed and approved by the AESO Board or the President and Chief Executive Officer as delegated by the AESO Board. Corporate policies are communicated to employees regularly and are accessible by employees at all times.

- The AESO's management, led by the President and Chief Executive Officer, is committed to maintaining the highest level of ethics and integrity. Management endeavours to foster this culture throughout the organization.

- The AESO's Code of Conduct serves as a framework for the AESO's Board, officers, employees and contractors of the AESO faced with difficult situations where laws and regulations are not enough to provide assistance in these situations. AESO Board Members and employees are required to indicate their compliance with the Code of Conduct on at least an annual basis.

- The AESO's management is responsible for establishing and maintaining adequate internal control over financial reporting. These controls are designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. Internal control over financial reporting, no matter how well designed, has inherent limitations and provides only reasonable assurance with respect to financial statement preparation and may not prevent or detect all misstatements.

  The AESO conducted an assessment of the design and effectiveness of the internal control over financial reporting based on the framework established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the AESO maintains effective internal control over financial reporting as of December 31, 2008.

- The Audit Committee reviews and monitors the system of internal controls, the systems for managing risk, the external audit process and the AESO's process for monitoring compliance with laws and regulations, with a view to ensuring best practices are followed.
- Risk assessment is a continuous process undertaken by management. The AESO's management is committed to proactively addressing potential risks identified and implementing appropriate mitigation action plans.
- The AESO reports its significant risks to the Audit Committee on a regular basis and provides updates on the implementation of mitigation strategies that are undertaken.
- The AESO, members of its independent Board and its employees are extended a degree of statutory liability protection consistent with the AESO's public interest mandate.
- The AESO carries insurance coverage that is deemed to be appropriate by management. The insurance coverage may not be adequate to cover all possible risks and the proceeds of any insurance claim may not be adequate to cover all potential losses.

8. FORWARD-LOOKING STATEMENTS

This MD&A contains forward-looking statements that are subject to certain assumptions and risks that create uncertainties. These assumptions and risks could cause actual results to differ materially from results anticipated by the forward-looking statements.

9. ADDITIONAL INFORMATION

Additional information relating to the AESO can be found on the corporate website at **www.aeso.ca**

Management's Responsibility for Financial Reporting

The financial statements included in the annual report are the responsibility of management and have been approved by the AESO Board. These financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP), and include the use of estimates and assumptions that have been made using management's best judgment. Financial information contained elsewhere in this annual report is consistent with that in the financial statements.

To discharge its responsibility for financial reporting, management maintains a system of internal controls designed to provide reasonable assurance that the AESO's assets are safeguarded, that transactions are properly authorized and that financial information is relevant, accurate and available on a timely basis. Internal controls are reinforced through the AESO's Code of Conduct, which sets forth the AESO's commitment to conduct business with integrity, and within both the letter and the spirit of the law.

The AESO Board, through the Audit Committee, is responsible for ensuring management fulfils its responsibility for financial reporting and internal controls. The Audit Committee meets regularly with management and the external auditors to discuss any significant accounting, internal control and auditing matters, to assure that management is carrying out its responsibilities and to review and approve the financial statements.

The financial statements have been examined by Deloitte & Touche LLP, the AESO's external independent auditors who are engaged by the AESO Board. The responsibility of these external auditors is to examine the financial statements and to express their opinion on the fairness of the financial statements in accordance with Canadian generally accepted accounting principles. The auditors' report outlines the scope of their examination and states their opinion. The auditors have access to the Audit Committee, with and without the presence of management.

David Erickson, CA
President & Chief Executive Officer (Interim)

Todd D. Fior, CA
Vice-President, Finance

Auditors' Report

TO THE MEMBERS OF THE ALBERTA ELECTRIC SYSTEM OPERATOR BOARD

We have audited the balance sheets of the AESO as at December 31, 2008 and 2007 and the statements of operations and comprehensive income and cash flows for the years then ended. These financial statements are the responsibility of the AESO's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the AESO as at December 31, 2008 and 2007 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte + Touche LLP

Chartered Accountants
Calgary, Alberta

January 30, 2009

Balance Sheet

As at December 31 (in thousands of Canadian dollars)	**2008**	2007
ASSETS		
Current assets		
Cash	**$ 12,746**	$ 61,672
Accounts receivable *(note 4)*	**122,316**	182,645
Prepaid expenses and deposits	**6,588**	2,686
AESO deferral account receivable *(note 8)*	**11,699**	–
	153,349	247,003
Capital assets *(note 6)*	**55,602**	42,994
	$ 208,951	$ 289,997
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities *(note 7)*	**$ 114,726**	$ 192,927
AESO deferral accounts payable *(note 8)*	**–**	58,006
MSA deferral account payable	**164**	5
Security deposits *(note 14)*	**1,032**	1,541
Deferred government grants *(note 5)*	**–**	267
Bank debt *(note 9)*	**91,600**	35,700
	207,522	288,446
Deferred rent	**1,429**	1,551
Equity *(note 1)*	**–**	–
	$ 208,951	$ 289,997

Asset retirement commitment *(note 11)*

Contingencies and commitments *(note 12)*

On behalf of the AESO Board:

Harry Hobbs
AESO Board Chairman

William D. Burch, FCA
AESO Board Vice-Chairman and Audit Committee Chairman

See accompanying notes.

Statement of Operations and Comprehensive Income

For the Year Ended December 31 (in thousands of Canadian dollars)	**2008**	2007
Revenue		
Transmission tariff	**$ 1,091,608**	$ 905,079
Energy market charge	**22,313**	13,654
Load settlement charge	**3,609**	5,136
Interest and other	**2,869**	5,327
	1,120,399	929,196
Operating costs and expenses		
Wires costs	**498,988**	441,185
Ancillary services costs	**311,940**	235,848
Line losses	**220,583**	183,787
General and administrative	**62,949**	52,187
Amortization *(note 6)*	**7,815**	9,190
Other industry costs	**16,725**	4,809
Interest expense *(note 9)*	**1,399**	2,190
	1,120,399	929,196
Net income and comprehensive income	**$ –**	$ –

See accompanying notes.

Statement of Cash Flows

For the Year Ended December 31 (in thousands of Canadian dollars)	**2008**	2007
Operating activities		
Net income	**$ –**	$ –
Amortization	**7,815**	9,190
Changes in non-cash working capital*	**(22,550)**	(106,462)
Net cash used in operating activities	**(14,735)**	(97,272)
Investing activities		
Capital asset additions	**(20,423)**	(8,214)
Net cash used in investing activities	**(20,423)**	(8,214)
Financing activities		
Increase (Decrease) in bank debt	**55,900**	(6,900)
(Decrease) Increase in deferred rent	**(122)**	31
(Decrease) Increase in AESO deferral accounts	**(69,705)**	46,355
Increase in MSA deferral account	**159**	21
Net cash (used in) provided by financing activities	**(13,768)**	39,507
Decrease in cash	**(48,926)**	(65,979)
Cash, beginning of year	**61,672**	127,651
Cash, end of year	**$ 12,746**	$ 61,672
Cash interest paid	**$ 1,379**	$ 2,155

** Consists of changes in accounts receivable, prepaid expenses and deposits, accounts payable and accrued liabilities, deferred government grants and security deposits.*

See accompanying notes.

Notes to the Financial Statements

December 31, 2008 and 2007

(All amounts are in thousands of Canadian dollars unless otherwise indicated)

1. NATURE OF OPERATIONS

The Independent System Operator (ISO), operating as the Alberta Electric System Operator (AESO), is a statutory corporation established on June 1, 2003 under the *Electric Utilities Act (EUA)* of the Province of Alberta.

Effective June 1, 2003, the AESO assumed responsibility for the operation of the competitive power pool; determining the order of dispatch of electric energy and ancillary services; providing system access service on the electric transmission grid; directing the safe, reliable and economic operation of the interconnected electric system; planning the capability of the transmission system to meet future needs; and administering load settlement. As of January 1, 2008 the responsibility for regulating the rules associated with load settlement transitioned from the AESO to the Alberta Utilities Commission (AUC).

The AESO is governed by the AESO Board, whose members are appointed by the Alberta Minister of Energy and are independent of any person or entity having a material interest in the Alberta electric industry. The AESO Board has an Audit Committee and a Human Resources, Compensation and Governance Committee.

The *EUA* requires that charges to industry, including the transmission tariff, energy market charge and load settlement charge, be set to recover the costs required to operate the AESO, and that the AESO be operated so no profit or loss results on an annual basis from its operations. The AESO has no equity.

The AESO's transmission-related financial activities are regulated by the AUC (Regulator) and approved based upon the AESO's annual General Tariff Applications.

Management views the operations as one fully-integrated operation; therefore, segmented information is not applicable.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP).

Use of Estimates – Preparation of these financial statements requires estimates and assumptions that affect the amounts reported and disclosed in the financial statements and related notes. These estimates and assumptions include information, regulatory decisions and other matters that are periodically influenced by third parties that may impact the timing of revenue and/or expense recognition. Actual results may differ from those estimates and assumptions due to factors such as the useful lives and impairment of capital assets, accrued liabilities, settlement of an asset retirement commitment and regulatory decisions. Any changes from current estimates or assumptions are accounted for in the period that they are determined.

Change in Accounting Estimate – During the year ended December 31, 2008, the estimate for the useful life of a capital asset was increased. The change in estimate was due to an assessment of the period in which the asset would be available and used in the AESO's operations from a five-year to a seven-year amortization period ending in 2012. The impact of this change on 2008 amortization was a decrease of $1.1 million.

Deferrals – The AESO utilizes deferral accounts to facilitate a matching of revenues and costs. On an individual basis for the transmission, energy market and load settlement operations, in circumstances where annual collections are in excess of the costs, the excess amount is recognized in the deferral accounts and refunded in the subsequent year. In circumstances where annual collections are less than the costs, the shortfall is recorded as revenue, recognized in the deferral accounts and collected in the subsequent year.

A portion of the energy market charge collected by the AESO is remitted to the Market Surveillance Administrator (MSA), a separate statutory corporation, according to its revenue requirement as provided in the *EUA*. When the annual revenue collected on behalf of the MSA through the energy market charge collection process is in excess of the funding payments made to the MSA, the excess amount is recognized in the deferral account and is incorporated into the estimated per megawatt hour charge for the following year.

Capital Assets – Capital assets are stated at cost. These assets are amortized on a straight-line basis over their estimated useful life as follows:

Software development	5 to 7 years
System coordination facility	Over the land lease term ending in 2025
Energy Trading System	8 years
Computer hardware, furniture and office equipment	3 to 5 years
Leasehold improvements	Over the lease term ending in 2014
Facility infrastructure	10 years
System coordination computer systems	Not commissioned at December 31, 2008

Interest costs attributable to and incurred during the development phase of large capital projects are capitalized. Capitalization ceases when the projects are substantially complete and ready for productive use. Payroll and payroll related costs associated with staff directly involved in software and hardware development are capitalized.

Revenue Recognition – The AESO's revenue is primarily derived through three separate charges: (i) the transmission tariff; (ii) the energy market charge; and (iii) the load settlement charge. Each of these charges is set to recover those costs directly attributable to one of the AESO's main functions as well as a portion of shared corporate services costs. Consistent with the requirements of the *EUA*, which requires the AESO to operate with no annual profit or loss, revenue is recognized equivalent to the aggregate of annual operating costs on a function-by-function basis.

The *EUA* requires the AESO to provide funding for the MSA with the amount to be recovered through the energy market charge. The energy market charge included in the AESO's statement of operations and comprehensive income does not include amounts recovered related to the MSA's funding requirements and the AESO's costs do not include amounts related to the operations of the MSA. The difference in the revenue collections and the monthly payments associated with the MSA are recorded in the MSA deferral account.

Deferred Rent – The lease costs associated with the 10-month, rent-free period will be recognized over the 10-year lease term.

Deferred Government Grant – The AESO recognizes government grants as a reduction to expenses in the period the expenses are incurred. Government grants received or receivable in advance of expenses incurred are recorded as deferred charges.

Employee Future Benefits – The AESO's employee future benefit program consists of a defined contribution plan. The AESO's contributions to employee future benefit plans are expensed as incurred.

Financial Instruments – The AESO has evaluated the five classifications of financial instruments, namely i) held for trading, ii) available for sale, iii) held to maturity, iv) loans and v) receivables and other financial liabilities, and designated its financial instruments.

Comprehensive Income – As the AESO does not have any Other Comprehensive Income, Net Income equals Comprehensive Income.

Significant Accounting Standard and Policy Changes – The AESO has adopted or has not yet adopted the following accounting and disclosure standards issued by the Canadian Institute of Chartered Accountants (CICA):

Recent Accounting Pronouncements Adopted

Description	Date and Method of Adoption	AESO Impact
Financial Instruments – Disclosures and *Financial Instruments – Presentation* requires disclosure of the significance of financial instruments to an entity's financial statements, the risks associated with the financial instruments, and how those risks are managed. (CICA Handbook Sections 3862 and 3863, which replace Section 3861)	January 1, 2008; prospective	Additional disclosures required, as included in Note 15
Capital Disclosures requires disclosure of objective, policies and processes for managing capital and quantitative data about capital. (CICA Handbook Section 1535)	January 1, 2008; prospective	Additional disclosures required, as included in Note 10
Inventories establishes standards for the measurement and disclosure of inventories including guidance on the determination of cost. (CICA Handbook Section 3031, which replaces Section 3030)	January 1, 2008; prospective	No impact
Going Concern requires an entity to assess and disclose its ability to continue as a going concern. (CICA Handbook Section 1400)	January 1, 2008; prospective	No impact

Recent Accounting Pronouncements Not Yet Adopted

Description	Date and Method of Adoption	AESO Impact
Goodwill and Intangible Assets establishes guidance for the recognition, measurement, presentation and disclosure of goodwill and intangible assets. (CICA Handbook Section 3064, which replaces Sections 3062 and 3450)	January 1, 2009; prospective	No impact
International Financial Reporting Standards (IFRS) – the Canadian Accounting Standards Board has published its strategic plan for convergence of Canadian generally accepted accounting standards with IFRS as issued by the International Accounting Standards Board. Restatement of comparative figures will be required.	January 1, 2011; retrospective	Currently being reviewed

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

Regulatory assets represent certain costs, incurred in the current period or in prior periods, that are expected to be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions of revenues associated with amounts that are expected to be refunded to customers as a result of the rate-setting process.

As of December 31,	**2008**	2007
Regulatory asset		
Transmission deferral	**$ 10,720**	$ –
Regulatory hearing costs	**–**	71
Regulatory liabilities		
Transmission deferral	**$ –**	$ 50,657

At December 31, 2008, the transmission deferral asset was $10.7 million based upon an accumulation of variances between transmission revenue collections and costs incurred in 2008 and prior years. The AESO applies to the Regulator for the approval and settlement of deferral balances. The transmission deferral balance is a regulatory asset or liability, based upon the expectation that amounts accumulated from one year to the next will be approved for collection from, or refund to, customers in a subsequent year. In the absence of rate regulation, GAAP would require that such balances be included in operating results in the year in which they are incurred. The regulatory asset is included in the AESO's deferral accounts receivable on the balance sheet at December 31, 2008.

The Regulator will issue a Utility Cost Order that approves allowable and recoverable hearing costs with the completion of a regulatory process. If approved, the regulatory asset will become an other industry cost and will be recovered from customers in that year. If the cost claim is disallowed, the amount will be included in general and administrative costs in that year. In the absence of rate regulation, GAAP would require that such costs be included in operating results in the year in which they are incurred. There is no regulatory asset or regulatory liability on the balance sheet at December 31, 2008 related to these costs.

All transmission-related financial activities of the AESO are subject to the Regulator's approval on an annual basis. Thus the recovery of transmission costs through the transmission tariff is subject to regulatory approval. With the formation of the AESO through the *EUA*, the AESO must be managed so that, on an annual basis, no profit or loss results from operations. Management believes that the ultimate recovery is assured due to the not-for-profit status of the AESO.

4. ACCOUNTS RECEIVABLE

As of December 31,	**2008**	2007
Transmission settlement	**$ 105,436**	$ 176,956
Energy market settlement	**1,513**	2,881
Trade	**15,367**	2,808
	$ 122,316	$ 182,645

5. GOVERNMENT GRANTS

In 2007, the AESO undertook an initiative to study the best approach to forecast wind power in Alberta. The Alberta Department of Energy and the Alberta Energy Research Institute committed to providing partial funding for this project. These grants relate specifically to this project and will not continue in the future. Full funding is conditional upon the completion of the study and providing a final report on the project findings. The AESO complied with the terms of the grant agreements and foresees no issues that would change this status. There is no contingent liability recorded for any repayment of grant amounts received or receivable. At December 31, 2008, $0.3 million in funding was received (2007 – $0.3 million) with the remaining $0.1 million receivable, for overall project funding of $0.7 million.

In 2008, the financial statements recognize a reduction to general and administrative expenses of $0.3 million (2007 – general and administrative expense reduction of $0.4 million and a deferred charge of $0.3 million related to the recognition of funding in advance of project expenses).

6. CAPITAL ASSETS

	Cost	**Accumulated Amortization**	**2008 Net Book Value**
Software development	**$ 31,457**	**$ 13,564**	**$ 17,893**
System coordination facility	**19,205**	**2,123**	**17,082**
Computer hardware, furniture and office equipment	**7,122**	**4,169**	**2,953**
Leasehold improvements	**4,072**	**1,340**	**2,732**
Facility infrastructure	**2,563**	**531**	**2,032**
Work in progress	**12,910**	**–**	**12,910**
	$ 77,329	**$ 21,727**	**$ 55,602**

	Cost	Accumulated Amortization	2007 Net Book Value
Software development	$ 27,122	$ 10,002	$ 17,120
System coordination facility	19,055	1,096	17,959
Energy Trading System	11,410	11,410	–
Computer hardware, furniture and office equipment	7,258	4,396	2,862
Leasehold improvements	2,976	914	2,062
Facility infrastructure	2,561	274	2,287
Work in progress	704	–	704
	$ 71,086	$ 28,092	$ 42,994

Work in progress relate to capital acquisitions associated with various hardware and software development projects (2008 and 2007) and the system coordination computer systems (2008) that were not commissioned or operational by the end of the year.

For the 12 months ended December 31, 2008, $2.3 million of payroll and payroll-related costs associated with staff directly involved in software and hardware development have been capitalized (2007 – $1.4 million) and interest costs of $0.1 million were capitalized in 2008 during the design and development phases of the system coordination computer systems project (2007 – nil).

7. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As of December 31,	**2008**	2007
Transmission settlement	**$ 85,965**	$ 150,465
Energy market settlement	**–**	23,498
Trade	**21,327**	14,033
Accrued liabilities	**7,434**	4,931
	$ 114,726	$ 192,927

The accounts payable trade balance includes flow-through customer contribution amounts of $1.9 million in 2008 and $2.8 million in 2007.

8. AESO DEFERRAL ACCOUNTS (RECEIVABLE) PAYABLE

	Transmission	Energy Market	Load Settlement	Total
Opening balance, January 1, 2007	$ 4,278	$ 6,610	$ 763	$ 11,651
2007 Operations	46,379	(298)	274	46,355
Closing balance, December 31, 2007	50,657	6,312	1,037	58,006
Interim disbursement of the 2004-2007 Deferral Account Reconciliation Application	(51,140)	–	–	(51,140)
2008 Operations	(10,237)	(9,141)	813	(18,565)
Closing balance, December 31, 2008	**$ (10,720)**	**$ (2,829)**	**$ 1,850**	**$ (11,699)**

9. CREDIT FACILITIES

The AESO has credit facilities of $140.0 million, comprised of a $70.0 million term revolving loan facility and a $70.0 million demand revolving loan facility. The facilities provide that the borrowings may be made by way of fixed rate offer loans, prime loans or bankers' acceptances, which bear interest at the rates specified in fixed rate offer loans, at the bank's prime rates, or at bankers' acceptance rates plus a stamping fee.

The $70.0 million term revolving loan facility is fully revolving for two-year periods with a term to September 2009 and a provision for one extension. If the facility is not extended, the amount outstanding would be repayable in full in September 2009. Included in the $70.0 million term revolving loan facility is the option to request letters of credit.

In addition to the two loan facilities, a demand treasury risk management facility of $9.0 million in deemed risk content is available to provide for interest swaps for up to $35.0 million in notional debt. This facility was not used in 2008 and 2007.

At December 31, 2008, $50.0 million was drawn on the demand revolving loan facility and a $10.0 million letter of credit was issued and $41.6 million was drawn on the term revolving loan facility. The letter of credit was issued as security for operating reserve procurement.

The amount of interest paid during the year was $1.4 million (2007 – $2.2 million) at an average interest rate of 3.2 per cent.

10. CAPITAL DISCLOSURE

In managing capital, the AESO reviews its cash flows from operations, including the transmission tariff, energy market charge and load settlement charge, to determine whether there are sufficient funds to cover its operating costs and pay for capital expenditures. To the extent that the cash flows are not sufficient to cover these expenditures, the AESO utilizes debt financing. The AESO has no equity or externally imposed capital requirements.

As of December 31,	**2008**	2007
Bank debt	**$ 91,600**	$ 35,700

11. ASSET RETIREMENT COMMITMENT

The system coordination facility is located on leased land. Under the terms of the lease agreement, the AESO is obligated, at the request of the landlord, to complete site restoration upon termination of the lease. The landlord's intentions are not determinable at this time. As the fair value of the obligation cannot be reasonably estimated due to the broad range of settlement dates and cash flows, any potential liability has not been recognized. Amounts will be accounted for in the period they are determined.

12. CONTINGENCIES AND COMMITMENTS

(i) The AESO leases office space, data processing equipment and land under various operating leases. The minimum lease payments associated with these leases are as follows:

Year	Amount *($ million)*
2009	3.2
2010	2.3
2011	2.2
2012	2.3
2013	2.4
Thereafter	3.4

(ii) To fulfil the duties of the AESO in accordance with the *EUA*, the AESO manages the procurement of ancillary services through contracts with third-party suppliers. These ancillary services include operating reserves, transmission must-run, under-frequency mitigation and system restoration. The contracts are for generation capacity and load reduction capabilities ranging in contract duration from one day to 14 years. The amount to be paid under each contract is dependent upon fixed and variable terms. The variable terms are based upon commodity prices, dispatch volumes and frequency.

(iii) As a result of events that occurred in 2007, the AESO may become party to a claim or legal action arising in the normal course of business. While the outcome of these matters is uncertain, the AESO does not currently believe that the outcome related to these matters or any amount that the AESO may be required to pay would have a materially adverse effect on the AESO as a whole.

(iv) The *EUA* requires the AESO to provide funding for the MSA with the amount to be recovered through the energy market charge. In 2008, $3.4 million was paid to the MSA (2007 – $3.0 million).

(v) The *AUC Act* requires the AESO to provide funding for the AUC with the amounts to be recovered through the transmission tariff and the energy market charge. In 2008, $16.6 million was paid to the AUC (2007 – $2.4 million).

13. EMPLOYEE FUTURE BENEFITS

The contributions to the defined contribution plan are based on a percentage of an employee's salary with the AESO matching employee contributions to a maximum percentage. There is no unfunded obligation related to the plan as contributions are paid to employees when earned. Total expense for the defined contribution plan was $2.5 million in 2008 (2007 – $2.2 million).

14. SECURITY DEPOSITS

Security requirements for financial obligations in excess of unsecured credit limits are met with cash deposits and letters of credit. All market participants and transmission customers who have financial obligations to the AESO must adhere to the Independent System Operator (ISO) rules and transmission tariff terms and conditions regarding security requirements. Unsecured credit limits are provided for an organization (or guarantor) with an acceptable credit rating from an AESO recognized bond rating agency, an organization that does not have a credit rating if they qualify for an AESO determined proxy credit rating, or for an organization that has an exempt status as determined through government legislation.

15. FINANCIAL INSTRUMENTS

Financial Instrument	Designated Category	Measurement Basis	Associated Risks	Fair Value at December 31, 2008
Cash	Held for trading	Fair value	Liquidity risk	Carrying value approximates fair value due to short-term nature
Accounts receivable AESO deferral accounts receivable MSA deferral account receivable	Loans and receivables	Fair value	Credit risk	Carrying value approximates fair value due to short-term nature
Accounts payable and accrued liabilities AESO deferral accounts payable MSA deferral account payable	Other financial liabilities	Initially at fair value and subsequently at amortized cost	Liquidity risk Market risk	Carrying value approximates fair value due to short-term nature
Security deposits	Other financial liabilities	Initially at fair value and subsequently at amortized cost	Liquidity risk	Carrying value approximates fair value due to short-term nature
Bank debt	Other financial liabilities	Initially at fair value and subsequently at amortized cost	Liquidity risk	Carrying value approximates fair value due to short-term nature and variable interest rates

Nature and Extent of Risks Arising from Financial Instruments

The AESO is exposed to the following types of risks in relation to its financial instruments:

a) **Credit Risk –** The risk that a counterparty may default on their financial obligations to the AESO. Due to the *EUA* requirement that the AESO be operated with no profit or loss from its operations, credit risk is ultimately borne by transmission customers and energy market participants though managed by the AESO.

Counterparties are granted certain levels of unsecured credit with the AESO based on their long-term unsecured debt rating provided by a major reputable corporate rating service satisfactory to the AESO or, in the absence of the availability of such ratings, the AESO has satisfactorily reviewed the counterparty for creditworthiness as appropriate. Letters of credit, cash on deposit and legally enforceable right to set off are used to mitigate risk where appropriate. There were no uncollectible receivable balances at December 31, 2008 and all accounts receivable are current.

b) **Market Risk –** The risk of a potential negative impact on the balance sheet and/or statement of operations and comprehensive income resulting from adverse changes in the value of financial instruments as a result of changes in certain market variables. This includes interest rate price and foreign exchange risks.

The AESO's bank debt is comprised of short-term bankers' acceptances that bear interest at market rates. Accordingly, the exposure to interest rate price risk in relation to the bank debt at the balance sheet date is not material.

The AESO conducts less than one per cent of its business in U.S. dollars and accordingly is subject to currency risk associated with changes in foreign exchange rates in relation to payables. The AESO monitors its exposure to currency risk and reviews whether the use of derivative financial instruments is appropriate to manage potential fluctuations in foreign exchange rates. The AESO has not entered into any derivative instruments with respect to currency risk.

c) **Liquidity Risk –** The risk that the AESO will not be able to meet its obligations associated with financial liabilities. The AESO does not consider this to be a significant risk as the available borrowing facilities and secured credit provide financial flexibility to allow the AESO to meet its obligations as they come due. The AESO does not consider there to be a present risk in relation to funds availability to the AESO under the existing borrowing facilities.

Summarized Quantitative Data Associated with the Above Risks

a) **Credit Risk –** At December 31, 2008, the AESO's maximum exposure to receivable credit risk was $134.0 million, which is the aggregate of accounts receivable and AESO deferral accounts receivable.

The AESO's receivables are due from counterparties that have provided security to the AESO or have been granted unsecured credit based on satisfactory credit ratings. As at December 31, 2008, the amount of financial assets that were past due was not material.

b) **Market Risk –** The AESO is exposed to currency risk on $2.2 million of U.S. dollar denominated financial liabilities at December 31, 2008.

- If the Canadian dollar increases (decreases) against the U.S. dollar by five per cent prior to the payment by the AESO, operating costs would decrease (increase) by $0.01 million and capital costs would decrease (increase) by $0.1 million.

c) **Liquidity Risk –** The AESO's bank debt and accounts payable and accrued liabilities generally have contractual maturities of six months or less.

ECO-AUDIT

Coated paper stock portion -
uses 1.2011 metric tonnes of paper which contains 10 per cent recycled post-consumer fibre.

Uncoated paper stock portion -
uses 0.2200 metric tonnes of paper which contains 100 per cent recycled post-consumer fibre.

Total savings achieved -
when recycled post-consumer fibre is used in place of virgin fibre.

- seven trees preserved for the future
- 8.6183 kilograms waterborne waste not created
- 11,065 litres wastewater flow saved
- 146.96 kilograms solid waste avoided
- 288.94 kilograms net greenhouse gases prevented
- 4,873,560 British Thermal Units of energy saved

This FSC logo for cover and narrative pages, 1-64.

This FSC logo for Financial pages 65-92.

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