

2007 Annual Report

# Powering Alberta



# Powering Albertans

*Our Annual Report cover features AESO employees and the public who all depend on electricity to power their lives.*

**It's invisible and yet we need it** for almost everything we do. Electricity is with us, quietly powering our day from the time we wake in the morning until the last light is switched off at night.



5:00am



8:00am

**Electricity is silently working for us** keeping our food fresh, clothes clean and homes warm. Power is there the instant a stove is turned on, a school lights up or a coffee maker is plugged in.

**Electricity is there when we need it** – to light up our homes and farms, to power our hospitals and schools, to energize our businesses and our entertainment.



**With the flick of a switch** we power our entertainment, education and recreation. Albertans can depend on reliable power every day because our system controllers are constantly balancing the supply of electricity with the demand for power minute-by-minute every day.

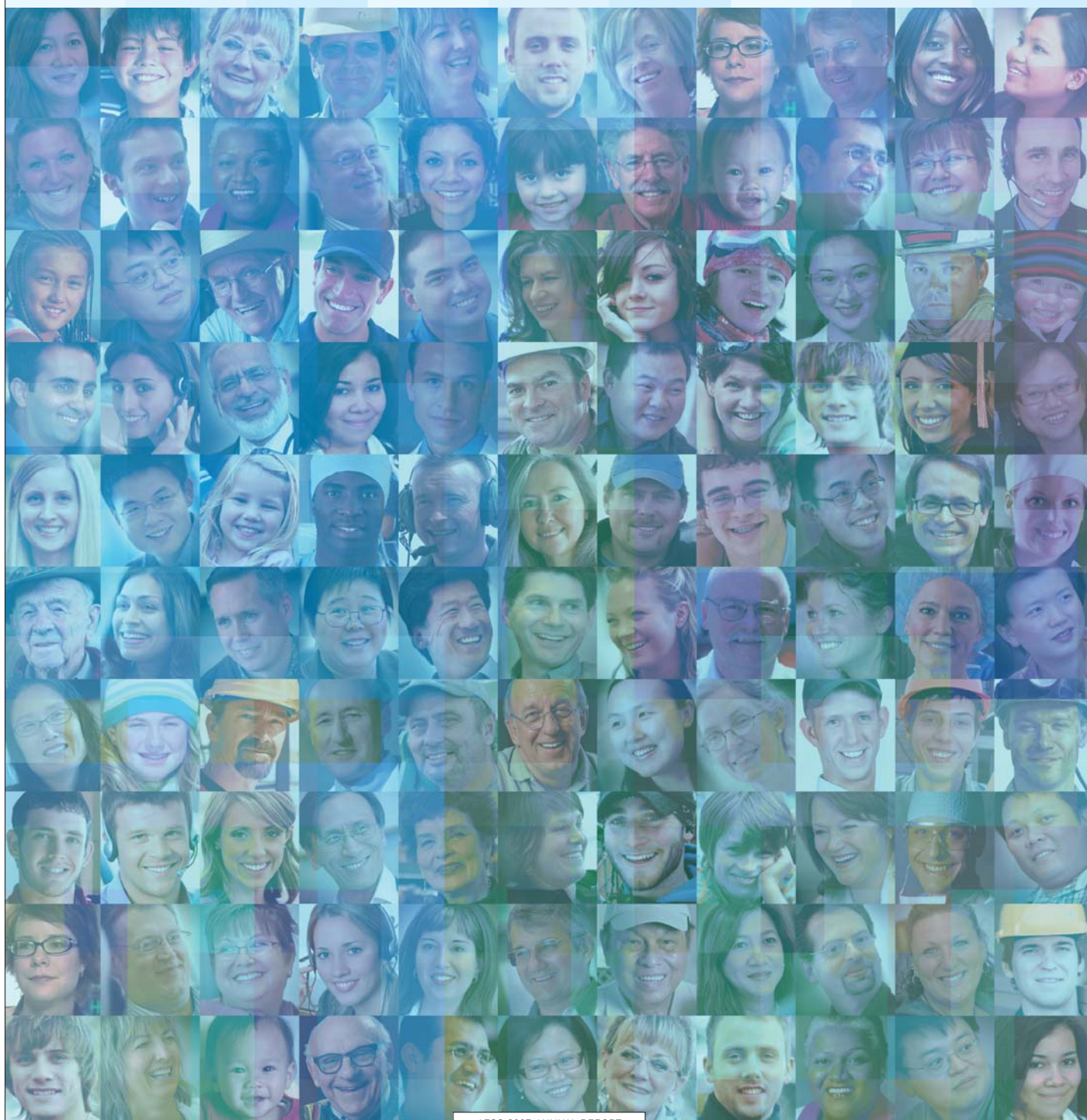


**At the AESO it's our job to make sure** that Albertans can continue to depend on electricity to be there when they need it. Looking ahead and developing long-term plans to make sure that we can continue to depend on electricity to power our lives, is a job the AESO takes care of on behalf of all Albertans.

**Power: our silent partner in every day living.** We take electricity for granted and yet we need it for nearly everything we do and use.

## Table of Contents

4	6	9	21	39	42	44	47	58
Message from the Chairman	Message from the CEO	Year in Review	Alberta Wholesale Market Statistics	Corporate Governance	Board Members	Executive Team	Management's Discussion and Analysis	Financial Statements and Notes





# Our Vision



The AESO 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.

## What we do . . .

Our job is to ensure all Albertans receive safe, economic and reliable power today and in the future.

## We are responsible for . . .

**Electric System Operations** – directing the safe, reliable and economic operation of the interconnected electric system.

**Electric System Development** – assessing the current and future needs of market participants and planning the capability of the transmission system to meet those needs.

**Electric System Interconnections** – providing transmission system access to the provincial grid.

**Market Development and Operations** – ensuring Alberta's wholesale electricity market is fair, efficient and openly competitive.

## How we do it . . .

**Innovation** – finding a possibility where one might not be readily apparent, or inventing a new approach when we're 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.

# Message from the Chairman



Harry Hobbs  
Chairman

**In collaboration with wind generators we've created a market operating framework to continue Alberta's leading role in fostering alternative energy sources.**

## A MESSAGE TO ALBERTANS

Looking back on the past year, I would be remiss not to underscore the amount of activity faced by the electricity industry and the AESO. Alberta continues to operate at a frenetic pace. The evolution of the marketplace has been extensive as fundamental government policy initiatives move to the implementation stage. This has meant a significant effort required by the executive management and team of employees at the AESO. The stretched transmission system continues to present complex operational and planning challenges. Human resource issues remain high on everyone's list of priorities.

In 2007/08, there was a desire at the AESO to alter the face of the organization to take a more active role in communication with the public and introduce significant improvements in the way we conduct our business. By year end, substantial progress had been made to achieve these objectives.

In late 2007, the implementation of the so-called "Quick Hits" package of market rules were published after overcoming some IT challenges. The Market Roadmap was also distributed to market participants and an extensive review process is underway. The last year has also seen a dramatic change in our drive to become a customer focused organization which sets objectives in concert with customers and then delivers timely results. Recent changes made by the customer team will facilitate this service improvement.

The second annual budget review saw the approval of a two-year budget and related business priorities. The budget review process is an initiative to work collaboratively with stakeholders to arrive at a fair and reasonable budget that accounts for the views of interested participants. It is a comprehensive, transparent process, the results of which are extensively detailed on our website. The success of this initiative was demonstrated the first time it was conducted and, to date, there is no reason to believe this year will be any different. To reach consensus among such a diverse group is a testament to the work of AESO personnel and our stakeholders to expend the effort to work through multiple iterations to achieve consensus.

In 2007, one of the significant accomplishments of the AESO was the removal of the temporary threshold on wind generation in the province. This initiative was accomplished in collaboration with wind generators and will result in a market operating framework to continue Alberta's leading role in fostering alternative energy sources.

Planning for the 500 kilovolt (kV) power line reinforcement between Edmonton and Calgary remains an imperative for the AESO and for Albertans who seek to have a vibrant, reliable transmission system and marketplace for electricity. We anticipate filing a new application once we have met with interested parties, including residents and the public, and have completed our analysis. It is important to stress that the AESO will not make a decision on a corridor or technological option until it has completed a comprehensive review of alternatives. That final decision will then be brought before the regulator for review at a public hearing to determine the "need" for a transmission reinforcement. Until that reinforcement is in place, the operations team at the AESO will continue to creatively manage the system to reduce the potential for disruptions. However, we must all recognize that the longer we wait to reinforce the system increases our exposure to events that trigger service disruptions.

Last year we undertook, as a public interest organization, to extend our outreach to members of the public. I am pleased to report that the communications team has distributed two publications to Albertans called "Powering Albertans". You may have recently seen the second of these pieces which was sent to 1.2 million households in Alberta to reach the full extent of the province. The publications seek to increase Albertans' knowledge of the AESO, the participants in the power industry, and how the industry works. We welcome your suggestions for future editions. Another component of our outreach program is our initiative to retain regional advisors in the various parts of the province to assist us with regional feedback, and to provide input on issues to help in our business planning.

Alberta sits well positioned to move forward and lead the country in many ways. There are issues, such as environmental initiatives, which promise to have significant impact on our business. We at the AESO believe there is a need for electric industry participants to take the initiative to define how electricity will form part of that future. The AESO is embarking on a broad analysis of the need for transmission facilities in the province over the next 20 years, consistent with our 20-year Transmission Outlook that we prepare every four years. This vision will seek to examine the breadth of issues related to transmission planning that will, at the end of the day, provide a 20-year blueprint of anticipated transmission to assist organizations in their planning and investment decisions, and to let Albertans know what is on the horizon. We look forward to engaging the electricity community in this discussion and working with the Department of Energy to complement its initiative for a comprehensive energy plan.

The AESO Board and executive team recently commenced our annual review of the strategic plan. This was an important event for us as four new Board members participated in the exercise for the first time. Hugh Fergusson, Robert McClinton, Walter Nieboer and Monica Sloan are all welcome additions to our Board. The transmission blueprint noted above is a cornerstone that will set our transmission direction for the years to come. We also seek to work with stakeholders and the public, and to take a leadership role in the development of the industry to facilitate continued, sustainable progress by the private sector that will benefit the public interest.

The AESO continues to conduct its activities in the public interest to achieve the largest benefit for Albertans as a whole. In the conduct of our role, we look forward to our future working relationships with stakeholders, agencies, the Department of Energy and the public. We expect the strong collaborative efforts with the AESO will continue.

I would like to extend thanks from the Board to the team of employees at the AESO who continue to dedicate themselves to making a difference in Alberta's power sector. From the leadership shown by the executive throughout the organization, Albertans should know that AESO personnel maintain a solid commitment to going above and beyond to achieve our goal to advance the organization's objectives to the benefit of Albertans.

Finally, I would like to extend my personal thanks to all our Board members for their support and dedication to the organization. It has been my pleasure to work with you over this past year.



**Harry Hobbs**  
*Chairman*  
*Board of Directors*  
*April 2008*

# Message from the CEO



Dale McMaster  
President & CEO

**By 2027, a total new supply of 11,500 MW could be required to meet the growing electricity demands of Albertans.**

## **DEAR STAKEHOLDERS:**

The past year has been one of many challenges for Alberta's electricity industry. Due to the AESO's central role in the industry, we see the effects of these challenges in all aspects of our core businesses: operating the interconnected electric system; planning the timely development of the transmission system; providing transmission system access to market participants; and, enabling the operation and development of the competitive market for electricity.

These challenges will continue into the foreseeable future. One of the biggest challenges facing the electric industry and our organization has been to reliably meet the rising demand for electricity driven by Alberta's strong economic growth. With this growth in demand comes increased requirements for new power supply, transmission system reinforcements and access to the transmission system for both generation and load customers. We currently estimate that Alberta will require an additional 5,000 megawatts (MW) of electricity supply by 2017. By 2027, a total new supply of 11,500 MW could be required to meet the growing electricity demands of Albertans. That represents a doubling of today's existing power capacity in Alberta over the next 20 years.

## **Responding to the need for supply**

We are pleased to see that the competitive market is once again responding to the need for new supply. A number of significant generation developments were announced in 2007 and early 2008. These proposed developments represent a diverse mix of energy sources including thermal technologies, wind power and hydroelectric generation development.

In addition to conventional power supply, the market is responding in innovative ways, investigating and investing in a variety of technologies – some new to Alberta such as nuclear and some new to the industry such as integrated gasification combined cycle with carbon capture. This innovation is being driven by the competitive market and growing demands for "green" generation options.

The transmission infrastructure in every region of the province must be strengthened to take this new supply to market, ensure reliability and facilitate the competitive market for electricity. This is especially true for the backbone of the electric system; i.e. transmission lines linking Fort McMurray, Edmonton and Calgary.



Our 10-year Transmission System Plan, published in February 2007, identified an investment of about \$5 billion in new transmission development, including projects underway. This investment in new infrastructure would result in an increase of about \$7 per month to the transmission charge on the average residential power bill by the year 2016. In 2008, we plan to update both the 20-year Transmission System Outlook and 10-year Transmission System Plan.

We continue to move forward on a number of significant transmission reinforcements. Some projects are already in the process of being constructed, Need Identification Documents (NID) for other projects have been submitted to the Alberta Utilities Commission (AUC) and other projects are in various stages of preparation. Over the past year, we filed a total of 48 NIDs for system reinforcements and interconnections for customers and distribution facility owners. We received 35 approvals during the year. We expect this high level of activity to continue in 2008.

That being said, our plans for electric system development experienced a significant setback when the Alberta Energy and Utilities Board (EUB) rescinded its 2005 approval of the 500 kV reinforcement of the system backbone between Edmonton and Calgary. The timely reinforcement of this critical part of the provincial grid is important to ensure reliability of the electric system, to enable the competitive market for electricity, to restore the capability of the existing intertie with B.C. and to improve system efficiency. This system reinforcement is of the highest priority for our organization. We are currently in the process of evaluating the alternatives that will meet the need and will carry out a comprehensive consultation to help determine our recommendation to the AUC.

#### **Improving public consultation**

To support all of our transmission planning efforts it is essential that we have an effective public outreach and consultation process. In 2007, we implemented enhancements to our consultation as part of planning for transmission reinforcement to support development of bitumen upgrading facilities in the Industrial Heartland region near Edmonton.

As part of our outreach and consultation for the Heartland project we published the "Powering Albertans" magazine to answer questions about the role of the AESO and provide an overview of how the electric system works. We followed that with a second edition which was delivered to all Alberta households in March 2008. Future editions will seek to clarify the roles of the various organizations in the power industry, describe the competitive market for electricity and explain the planning and development of the transmission system in greater detail.

#### **Enhancing customer service**

To better respond to an unprecedented demand for interconnections to the transmission system, we created a new customer service team to focus on the more complex industrial transmission system interconnections. During 2008, we will be reviewing our interconnection processes with industry colleagues and stakeholders to ensure the requirements of our customers are met in a timely and cost-effective manner.

In 2007, a total of 87 applications for transmission service were received as compared to 66 in 2006. This 32 per cent increase was due to the large number of proposed wind power projects, as well as major interconnections associated with oilsands projects and heavy oil upgraders.

#### **Addressing operational challenges through innovation**

As our customer service team focuses on meeting customer needs for a record number of interconnection requests, our operations staff are finding innovative ways to meet the operational challenges of provincial growth.

Until new transmission infrastructure is constructed and in service, the operation of Alberta's electric system is increasingly complex. This is especially true of the Edmonton to Calgary reinforcement, as we will be operating the system at or near limits more frequently and for longer durations, which increases the level of risk to system reliability.

To meet this operational challenge we've developed innovative ways to extract more performance from a stretched transmission system while maintaining system reliability. We enhanced the quality of our operating tools for system monitoring and our policies, procedures and training for our system controllers.

It is essential that the tools and technology used to operate the system keep pace with the needs of the marketplace. Accordingly, we are investing \$14 million to develop and implement a new Energy Management System (EMS). The new EMS will provide our expert team of system controllers and operations planners with the tools and technology needed to meet the evolving operational needs of Alberta's power system and marketplace.

#### **Implementing market enhancements**

It is imperative that investors have confidence in the market and the associated price signals because we depend on the competitive market to provide adequate supply to meet the load requirements of the province.

As the market continues to mature, it will evolve to meet the needs of market participants. A significant step in that evolution was achieved in the past year as we implemented a significant number of market modifications outlined in the Government of Alberta's Electricity Policy Framework. These enhancements are expected to increase visibility of available supply, enhance merit order depth and stability, and improve price fidelity.

These complex changes were implemented on existing computer systems that were designed and built to facilitate a much simpler market structure and their capacity to successfully implement further change is limited.

Over the course of the next year we will create a comprehensive vision and development plan to improve or replace computer systems required to operate the market to ensure that we can meet the demands of the continuing evolution of the competitive market.

### **Market Roadmap provides clarity**

As noted above, the competitive market will continue to evolve to meet the needs of market participants. In 2007, we published a five-year market development plan referred to as the Market Roadmap, which provides stakeholders with context and timelines for a broad range of future market design initiatives. It also provided the opportunity for stakeholders to submit feedback on these initiatives and their relative priorities.

In collaboration with stakeholders we worked on a number of important market design initiatives in the Roadmap including long-term adequacy, congestion management and operating reserves market redesign. In 2008, we will continue work on these initiatives, implement a number of market elements required by the amended Transmission Regulation and advance the design and implementation of the Government of Alberta's market power mitigation framework.

To assist us in our role of enabling the competitive market, we established a Market Advisory Committee (MAC) of senior representatives from a broad spectrum of the marketplace.

### **Leadership in wind development**

One of the great success stories of the competitive market in Alberta is the tremendous growth of the wind power industry. Over the course of the past year we've built on our national leadership in terms of the volume of wind power connected to the grid, and we achieved other firsts for wind interconnection standards and forecasting of wind patterns.

In close collaboration with wind generation developers, we removed the temporary 900 MW threshold for wind power through the development of a market and operational framework. This framework will, through market forces, facilitate the integration of as much wind power into the Alberta system as is feasible without compromising system reliability or the fair, efficient and openly competitive operation of the market.

### **New regulatory oversight**

In late 2007, the Government of Alberta passed legislation creating the AUC to carry out the regulatory oversight for the electricity industry that was previously provided through the EUB.

The scope of the AUC was expanded to include some competitive market responsibilities including, but not limited to, the approval of market rules which are proposed by the AESO.

We are looking forward to working collaboratively with the commissioners, management and staff of this new entity to help ensure that the electric system and the competitive market continue to develop and operate in the public interest.

In closing, I would once again like to extend my sincere appreciation to all stakeholders, for their support and cooperation. I continue to believe that a consultative and collaborative approach results in a better outcome to meet the reliability needs of Albertans and the business needs of market participants.

I would also like to acknowledge our Board of Directors. Their oversight and advice over the past year has been of great value.

Finally, I would like to extend my gratitude for the continued contribution and commitment of our employees – our most valuable asset.

As we face the many challenges ahead, we at the AESO remain committed to our core values of leadership, integrity, quality, innovation and collaboration. These values guide us in the delivery of our mission to the benefit of all Albertans.



**Dale McMaster**

*President and Chief Executive Officer*

*April 2008*

# 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 stakeholders and other interested parties with information about our key accomplishments and the significant initiatives we've undertaken in 2007. In the following section we summarize our efforts to fulfil our mandate and achieve strategic and operational objectives in each of our core business areas. Our business plan is available on our website at [www.aeso.ca](http://www.aeso.ca) and follow the path: Business Plan and Budget.*

- **Electric System Operations**
- **Electric System Development (Transmission)**
- **Electric System Interconnections**
- **Market Development and Operations**



# Electric System Operations

We are responsible for directing the safe, reliable and economic operation of the interconnected electric system. Our objective is to ensure that the Alberta Interconnected Electric System (AIES) is operated in a reliable manner in compliance with all applicable reliability standards. We accomplish this through developing and maintaining an appropriate set of system operating limits and a comprehensive set of Operating Policies and Procedures (OPPs). In addition, all of our system controllers participate in an extensive training program and are certified by the North American Reliability Corporation (NERC).

## Managing today's operational challenges

Operating Alberta's integrated electric system has become more complex today due to the following factors:

- ▶ there has been only one major transmission line constructed in the past 20 years;
- ▶ considerable growth in load is placing increasing demands on the transmission system;
- ▶ operation of a dynamic wholesale market with about 200 participants, and the ongoing evolution of electricity market rules;
- ▶ a substantial increase in the number and complexity of transmission system access service requests and the need to integrate these facilities in a timely and reliable manner; and,
- ▶ implementation of a market and operational framework to integrate a significant increase in wind power.

These challenges are being met in a number of ways, including continued emphasis on outage coordination, operating tools, well defined procedures, training for our system controllers and continued emphasis on comprehensive analysis and follow-up after any system disturbance.

We have also continued with our program to review and consult with generating unit owners regarding voltage support requirements and to verify the capabilities of generating units. The management of system voltages is critical and affects system-wide performance by supporting system reliability and power transfer levels.

We continue to investigate and implement innovative ways to increase the transfer capability of the system while ensuring reliable power for Albertans. One initiative currently under review is the use of dynamic thermal line ratings which will allow our system controllers to operate transmission lines closer to their actual physical limitations. This requires that we develop more sophisticated operating tools and procedures for our system controllers.

In 2007, we completed the framework to provide comprehensive, forward-looking assessments of the reliability of Alberta's electric system. These assessments include information about the adequacy of both power supply and the transmission system, and near-term planned system upgrades.



*We continue to investigate and implement innovative ways to increase the transfer capability of the system while ensuring reliable power for Albertans.*

### Wind power: an Alberta success story

Alberta has taken a leadership role in Canada in finding ways to accommodate the integration of wind generation into the power system. At present, Alberta leads the nation with the greatest amount of wind power connected to the grid. There is also a substantial amount of new wind power in various stages of development.

Alberta was the first jurisdiction in Canada to develop wind interconnection standards and to conduct detailed studies on forecasting wind patterns. In November 2007, we began publishing a weekly wind power market and operational report on our website. To view the report visit our website at [www.aeso.ca](http://www.aeso.ca) and follow the path: Grid Operations > Wind Power > Wind Power Studies.

We've achieved our leadership position in large part due to the success of our collaborative efforts with industry, and in particular, our executive steering committee with the Canadian Wind Energy Association (CanWEA). It is imperative, both to system reliability and the successful development of renewable resources in Alberta, that there is a common understanding of the impact of wind generation on power system operations, and that it is accommodated in an open and transparent manner.

The Market and Operational Framework for Wind Integration forms the foundation for initiatives required to further refine and define rules, tools and OPPs needed to integrate as much wind power into the Alberta system as is feasible without compromising system reliability or the fair, efficient and openly-competitive operation of the market. The Framework replaces the 900 megawatt (MW) temporary threshold, which was removed in September 2007 – three months ahead of schedule.

The implementation of the Market and Operational Framework for Wind Integration is progressing and the AIES is operating reliably with 500 MW of wind power connected. We continue to work with industry to develop wind power management procedures, power management technical requirements, wind power forecasting, operator tools, and practices regarding ancillary services forecasting and procurement. As of February 2008, there was 9,300 MW of wind power in the interconnection queue.

For additional information on the status of our initiatives and the Market and Operational Framework for Wind Integration visit our website at [www.aeso.ca](http://www.aeso.ca) and follow the path: Grid Operations > Wind Power.



*Alberta leads the nation with the greatest amount of wind power connected to the grid.*



*We continue to move forward on a number of significant transmission reinforcements required to meet the growing demand for reliable electricity in Alberta.  
Photo courtesy of AltaLink Management Ltd.*

### **A made-in-Alberta approach for reliability standards**

The NERC is leading a major initiative in the U.S. to implement mandatory reliability standards in the electricity industry. Currently there are 120 standards in various stages of development and implementation. Alberta's system is connected to the U.S. Pacific Northwest via the transmission intertie with B.C. and to the mid-continental U.S. market through the intertie with Saskatchewan (Sask.). Although Alberta is not directly obligated to comply with the NERC standards, we operate Alberta's system in the spirit and intent of these reliability standards.

In 2007, we established the Alberta Reliability Committee (ARC), a collaborative effort with industry and the Alberta Utilities Commission (AUC) to ensure the standards are appropriate for Alberta and that the responsibilities are clearly defined. We have also formed working groups with generation and transmission facility owners and operators to ensure that reliability standards adopted are consistent with the intent of the NERC standards, while recognizing any structural and operational differences in Alberta. Implementation of new standards being done in collaboration with stakeholders, will be phased-in to allow time for all parties to understand the intent of the standards, develop the tools and processes required to fully implement the standards, verify data and ensure compliance.

### **New policies ensure high standards**

Our OPPs are a critical component of how we ensure safe, reliable and economic operation of Alberta's electric system. In 2007, we implemented 48 OPP revisions to address system reliability, system changes, market services initiatives, commercial/contract changes, system limit changes and general updating. To view our OPPs visit our website at [www.aeso.ca](http://www.aeso.ca) and follow the path: Rules and Procedures > ISO Rules > Current Operating Policies and Procedures.

The AESO will undergo a NERC Reliability Readiness Assessment in 2008. In preparation for the NERC assessment, we arranged for an independent evaluation of our practices which provided a positive endorsement of our system coordination centre (SCC) facilities, our training and electric system restoration programs and our policies and procedures. The evaluation also identified some minor areas for improvement, which we are addressing before the Reliability Readiness Assessment in June 2008.



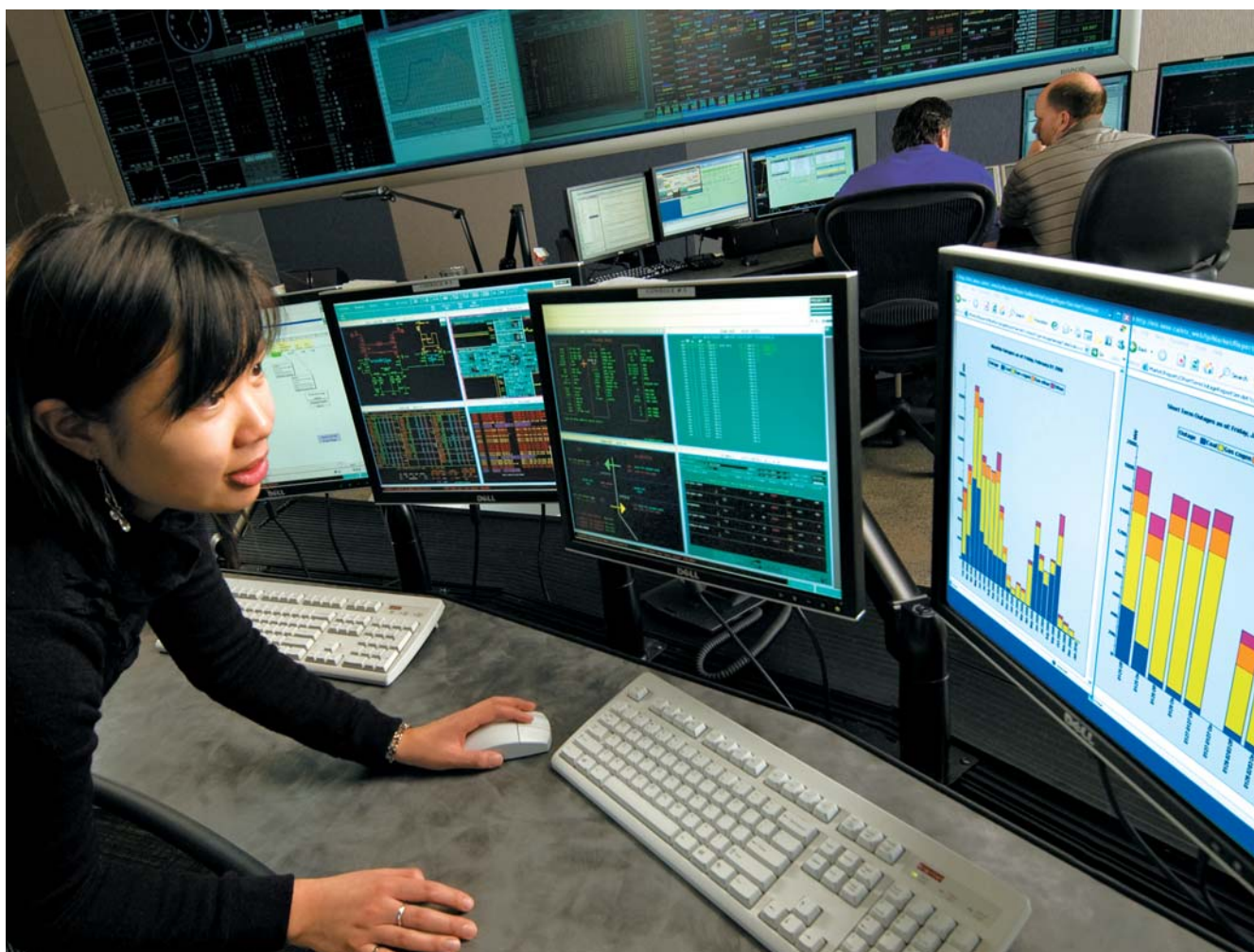
### New technology to meet tomorrow's needs

The Energy Management System (EMS) is the 'engine' of our SCC. It enables our system controllers to perform real-time activities such as balancing supply and demand, monitoring the status of the provincial electric system and performing reliability assessments 24 hours a day, seven days a week, 365 days a year.

The current EMS has served us well over the past 10 years, during which time we've improved the technology to keep pace with our requirements to manage the power system and facilitate Alberta's wholesale electricity market. In 2008 and 2009, we are investing \$14 million to develop and implement a new EMS. The new EMS will provide our system controllers with the necessary tools and technology to meet the evolving needs of Alberta's power system and market which continues to be more diverse and complex.

### Robust system restoration plan

We have a robust plan to restore the Alberta system in the unlikely event of a serious system disturbance or outage. To maintain our coordination channels and keep our plan current, we lead two drills a year with almost 200 industry participants who practice their part of the plan. Participants in our drills this year included our system controllers, transmission facility operators, generation facility operators, electric distribution system operators, as well as operations staff from British Columbia Transmission Corporation (BCTC), Saskatchewan Power Corporation and the Pacific Northwest Security Coordinator. After the drills were completed, we identified areas for improvements and updated the provincial restoration plans. These improvements were reviewed and endorsed by stakeholders, who are also members of our Transmission Operating Committee.



*The new Energy Management System will provide the tools and technology to meet the evolving needs of the power system and market.*

# Transmission

## Electric System Development

We are responsible for assessing the current and future needs of market participants and planning the capability of the transmission system to meet those needs. Credible and cost-effective system planning is a process which proactively identifies, plans, achieves approvals, and initiates implementation of required system reinforcements. This ensures that transmission facilities are in place to maintain reliable and economic transmission system operation and the facilitation of competitive electricity markets.

## Electric System Interconnections

We are responsible for providing customers with transmission system access service to the Alberta power grid. Through effective planning and design of transmission facilities, 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 interconnected provincial transmission system.

## Managing today's growth challenges

When an economy is growing at the pace of Alberta's, the need for power grows right along with it. During the last five years, load has increased at a rate equivalent to adding two cities the size of Red Deer (population of about 86,000) to Alberta's power system each year.

To meet these growing needs, our most recent 10-year Transmission System Plan, published in February 2007 identified an investment of about \$5 billion in projects underway and proposed new transmission development. If all the potential concepts examined in the plan are required and built, this total investment in critical infrastructure would result in less than a \$7 transmission charge on a residential customer's monthly power bill. You can find our 10-year Transmission Plan and 20-year Outlook and the brochure "Planning for Alberta's power future" on our website at [www.aeso.ca](http://www.aeso.ca) and follow the path: Transmission > Planning > Long-term planning.

In the fall of 2007, we started consultation to update our long-term transmission system plans for Alberta. To meet anticipated load growth, about 5,000 MW of new power supply could be needed by 2017. By 2027, a total new supply of 11,500 MW could be required to meet the growing electricity demand of Albertans. This represents a doubling of Alberta's current power generation capacity in the next 20 years.

The demands placed on the transmission system continue to grow at a rapid pace, and required reinforcements are critical to meeting those demands. The transmission infrastructure must be strengthened to facilitate the competitive market for electricity and to ensure system reliability.

## Major system reinforcements moving ahead

In 2007, we filed 48 Need Identification Documents (NIDs), which seek regulatory approval to reinforce the system. These included nine major system projects and other interconnections for customers and distribution facility owners. During the year, we received regulatory approval on 35 NIDs.

In 2008, we expect to file NIDs for between 10 and 15 significant system reinforcements. Our key priorities in 2008 are to file NIDs for reinforcement into the Fort McMurray area, for significant transmission reinforcement between Edmonton and Calgary, and system development throughout southern Alberta to facilitate the integration of wind power. In 2009, we expect to file a NID for a major system reinforcement into the Industrial Heartland region. This region comprises portions of Strathcona, Sturgeon and Lamont Counties. These municipalities, together with the City of Fort Saskatchewan, have formed an association to coordinate development and planning of infrastructure in the area. During 2008, we will be filing NIDs for the interconnection of industrial projects in the area.

In the city of Edmonton, we expect EPCOR Utilities Inc. will complete construction of a reinforcement involving the installation of about 10 kilometres (km) of 240 kV underground transmission line into downtown Edmonton. The line is expected to be in service before year end 2008.

In northwestern Alberta, we are on schedule to meet the April 2010 in-service date for the Brintnell/Wesley Creek and Wesley Creek/Hotchkiss facilities. We received approval for the NID for this

transmission development, which includes more than 700 km of transmission line, after extensive industry consultation and without the need for a regulatory hearing. ATCO Electric also received regulatory approval to build the facilities without the need for a hearing.

In northeastern Alberta, we are advancing our technical analysis and consultation to reinforce transmission from Ellerslie into Fort McMurray. We expect to file a NID for this transmission reinforcement in 2008 after consultation is completed.

In southwestern Alberta, AltaLink Management Ltd. filed its facilities application for transmission development in August 2007. In late March 2008, the AUC commenced the regulatory process for this application. We received regulatory approval for the NID regarding this transmission development in 2005.

In November 2007, we filed a NID for the first phase of transmission reinforcement in southeastern Alberta to ensure reliability of supply and to restore the capability of the Sask. intertie. The second phase, which will substantially increase the capability of the system to accommodate upwards of 3,000 MW of wind development, will be combined with related work in the southwest region. We expect to file a NID in 2008 after public consultation.

### **Public outreach and consultation programs enhanced**

We made a number of significant enhancements to our consultation process, principles and practices in 2007. Our objective is to engage stakeholders, including residents, early in the process to gather input, answer questions and support meaningful consultation opportunities among all interested parties.

Early in the year, we invited the transmission facility owners involved in the Industrial Heartland transmission development to work collaboratively with us to develop a consultation approach for that project. We used the same consultative approach to engage the public regarding transmission development planning for the southern part of Alberta.

Through open houses, advertisements, industry meetings, group presentations, publications and discussions on these two projects we have been in contact with about 500 public stakeholders. We asked open house participants to rate the amount and quality of information they received and their overall experience. In the south area consultation, 94.7 per cent of respondents said they were satisfied, and in the Heartland area consultation we had 87 and 81 per cent satisfaction ratings in two surveys. These results indicate that not only are our consultation processes satisfying requirements set out in the AUC rules, they are also satisfactory to a number of public stakeholders. At the same time, we strive to continuously improve our consultation processes and practices.



*We continue to investigate and implement innovative ways to meet the operational challenges of unprecedented provincial growth.*



## Why is the Edmonton to Calgary transmission reinforcement so important?

As our population and the economy continue to grow, we're putting more and more pressure on the transmission lines we have in place. In the last 20 years, there's been only one major line and some regional facilities built, but the system backbone between Edmonton and Calgary has not been reinforced. That's important to Albertans because there are a number of large power plants located around Edmonton and in northern Alberta, which provide nearly three quarters of all the energy used in Alberta. These power plants have low operating costs and Albertans depend on the electricity supplied by these plants to meet the normal everyday demand for power across the province. Some of these power plants are being upgraded and new ones are being planned. Even though new plants might also be built in other areas of the province, this supply will continue to be important in meeting Alberta's hourly power needs. It's critical to be able to move this electricity from where it's produced to other areas of Alberta to help meet the growing demand for power and to facilitate the competitive market. A priority in 2008 and 2009 is to obtain approval for and facilitate the construction of the transmission reinforcement between Edmonton and Calgary.

### Improving customer service for system access

In November 2007, we announced a new team to focus on ensuring that the customers' needs and interests remain in the forefront as interconnection projects move through the planning, engineering and regulatory approval processes.

We received an unprecedented number of system access requests from customers in 2007 and this trend is expected to continue. During the year, we managed a total of 200 customer-related interconnection projects in addition to 43 system projects. We received 87 applications, a 32 per cent increase over the 66 applications received the prior year. This increase was heavily influenced by the significant volume of system access requests from wind power developers, as well as a number of system access requests for other forms of generation. We also received applications for load additions associated with oilsands and upgrader facilities, which are more complex and of a larger scale than typical interconnection requests we've received in the past.

Working with industry, the AESO has developed a regional plan for the oilsands area north of Fort McMurray. This plan will integrate system reinforcements in the area with system access interconnections to serve customers.

The large number of system access requests for wind generation in southern Alberta required an innovative approach to providing interconnection proposals. We developed an integrated plan for these interconnection proposals, which was reviewed with wind developers and is being implemented in 2008.

### Advancing discussions on Alberta's intertie capacity

With only two transmission interconnections with neighbouring jurisdictions providing limited export and import capacity, the AES is one of the least interconnected jurisdictions in Canada. The market may be unable to clear surplus energy (off-peak), or to access more competitively priced supplies (on-peak), which adversely impacts surplus and scarcity pricing and increases the on/off peak spread and price volatility. The absence of sufficient intertie capacity may also impact reliability because imported power can serve as an effective buffer against supply shortfalls and wind variability.

In 2007, we continued work with BCTC to explore the benefits and costs of additional intertie capacity between Alberta and B.C. We expect consultation on the preliminary results to take place in 2008. Further analysis will be undertaken after the consultation has occurred.

We are also working with companies that are proposing merchant transmission lines to connect Alberta to external jurisdictions. We make sure these projects are safely and reliably connected with Alberta's existing transmission system, and we identify any direct benefits that could be delivered to Alberta as a result of these interconnections.

Montana Alberta Tie Ltd. has received conditional regulatory approval for a proposed line from southern Alberta to Montana, while TransCanada is proposing the NorthernLights project, a planned transmission line that will run from northern Alberta to northern Oregon in the U.S. Should these lines be built, the project developers will be responsible for project construction costs. The developers will look to recover their costs from those who will make use of the lines to transport power into or out of Alberta.

# Market Development and Operations

We are responsible for facilitating the development and operation of the competitive wholesale market for electricity, including financial settlement. We ensure Alberta's competitive electricity market continues to operate in the best way possible (fair, open, competitive and efficient with a trusted index) and demonstrate that reliability is not compromised while sustaining a predictable market structure that adds long-term value.

## Stabilizing the market and regulatory frameworks

Our leadership to facilitate and maintain a framework that instils confidence in Alberta's market is imperative. Market participants must be confident that they have a fair opportunity to compete and earn a reasonable return on their invested capital. If participants do not believe that either the market or access to the transmission system is fair, they may decide to limit their investment or move it to another marketplace. If Alberta is to ensure adequate generation supply for the future, we must instil investor confidence and provide stability in all aspects of the market and regulatory frameworks.

The Department of Energy (DOE) has released a number of policies which have resulted in changes to the market and regulatory structure in the last few years. We have been working with the DOE and market participants to implement the required changes in a collaborative and transparent manner that balances the rights and obligations of all market participants.



*System controllers must keep pace with changes to market rules while operating a system that is stretched.*

## Advancing market policy

Over the past few years the DOE has introduced several policy initiatives including the Electric Utilities Act (EUA) Section 6 review, Alberta's Electricity Policy Framework (released in June 2005) and the revised Transmission Regulation (2007). These initiatives together with other major industry developments, such as wind energy integration result in required changes to existing market rules and the development of new rules that directly affect market participants. These changes also introduce additional complexity for system controllers who must keep pace with changes to market rules while operating a system that is stretched more frequently and for longer durations than ever before.

In early 2008, the AUC was established to replace the Alberta Energy and Utilities Board (EUB) as the regulator for the electricity industry. The AESO will continue to develop, consult on and implement market rules; however, under new legislation, the AUC will now approve market rules.

Due to our comprehensive consultation process, market initiatives are often multi-year efforts. In 2008 and 2009, we plan to advance the various amendments to the energy and ancillary services markets outlined in our first edition of the Five-year Market Roadmap published in August 2007.

The first edition received positive feedback from stakeholders. The Roadmap is intended to provide context for a broad range of market design initiatives and reinforce the current market structure going forward. An updated Market Roadmap will be developed in the first half of 2008 for stakeholder review.

We aim to complete the implementation of changes arising from the revised Transmission Regulation and to seek ways to enhance the value of Alberta's existing transmission interties, while supporting the resolution of the policy questions related to the construction of additional intertie capacity. In the following sections, we outline the significant activities completed and initiated in 2007.

### Implementation of Alberta's Electricity Policy Framework

On June 6, 2005 the DOE released a policy documenting their refinements to the framework for the Alberta wholesale electricity market. The policy amendments focused on addressing short-term and long-term adequacy of supply and other inter-related wholesale market issues. Through industry consultation, specific initiatives were identified as having an immediate effect on the visibility of available supply and the fidelity and credibility of the pool price signal.

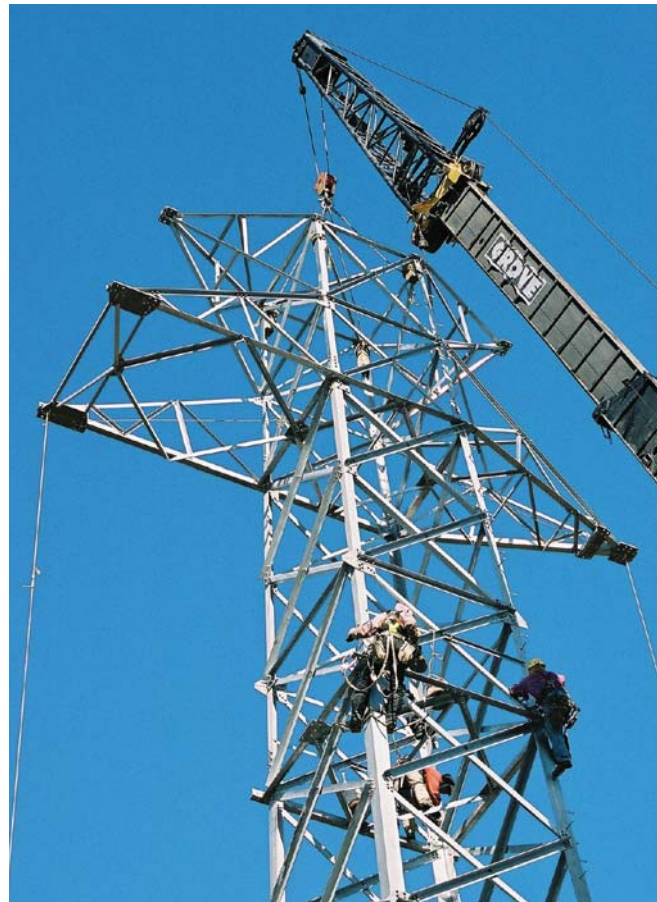
In December 2007, we successfully implemented the first phase of initiatives to address the policy amendments. This project was originally scheduled for implementation in May 2007, but the magnitude and complexity of implementing the new rules made it necessary to significantly strengthen aspects of our IT systems. This included several changes affecting the wholesale electricity market's Energy Trading System (ETS) and the SCC dispatch tool. In addition to the IT upgrades, new market rules including the Dispatch Down Service (DDS) were implemented in December. These rule enhancements are intended to provide stability to the merit order, payments to suppliers on the margin and reconstitute the pool price for transmission must-run (TMR). In advance of our six-month review in June 2008, preliminary results indicate the merit order is better populated and more stable, and price fidelity, particularly pool price reconstitution through DDS, has improved.

### Transmission Regulation initiatives on track

The amended Transmission Regulation (2007) expanded the scope of our out-of-market rule making requirements to include generator outage coordination, reliability unit commitment, ancillary services directives and a load curtailment priority plan. We are moving ahead to implement these initiatives in an integrated fashion.

### Approved AESO tariff provides stability and clarity

Following a process that spanned the better part of two years, we received a decision from the AUC on our 2007 general tariff application. Overall, the decision provides stability and increased clarity with respect to rates and terms and conditions for transmission system access service. For the first time in the AESO's history, the regulator approved the forecast revenue requirement relying on the rigour of our 2007 Budget Review Process with stakeholders and approval of the AESO Board.



*ATCO Electric contractors install the top section of a 240-kilovolt, double-circuit steel lattice transmission tower. Photo courtesy of ATCO Electric.*

In 2007, we issued a congestion management recommendation paper and held two stakeholder sessions to gather comments and provided a preview of the recommendations on outage coordination, reliability unit commitment, ancillary services directives and the load curtailment priority plan.

We published a Transmission Regulation recommendation paper for stakeholder comment in December 2007. The paper addresses AESO's recommendations pertaining to:

- ▶ directions it may give to the owner of a generating unit that is not operating or scheduled to operate for any reason, including as a result of a planned or forced outage, when it is required for reliable system operation; and,
- ▶ implementation of a load curtailment priority plan which, in the event of a generation supply shortfall or transmission issue, will provide for the interruption of service to customers in a priority ranking.

We gathered additional input and guidance from our newly-established Market Advisory Committee in January 2008. We are on schedule to develop rules to meet the April 2008 timeline.

For additional information, or to view any of the discussion papers or consultation visit our website at [www.aeso.ca](http://www.aeso.ca) and follow the path: Market > Market Policy Implementation.



### Settlement of Article 11 achieved

We reached a negotiated settlement with stakeholders on the matter of TMR compensation (referred to as Article 11), which was a controversial and unresolved issue in the industry for many years. The settlement constitutes a significant accomplishment by all stakeholders involved and demonstrates the ability of participants with divergent interests to work collaboratively to resolve a variety of issues. The settlement was approved by the AUC.

### AESO establishes new Market Advisory Committee

We have established a standing Market Advisory Committee. The primary purpose of this new committee is to augment the capability of the AESO's internal resources and to support effective consultation by obtaining stakeholder input and advice on wholesale market and tariff related matters including, but not limited to, the AESO's:

- ▶ Market Services planning and priorities (Market Roadmap);
- ▶ interpretation of approved and proposed government policy;
- ▶ policy implementation recommendations, alternatives and impacts; and,
- ▶ input on future government policy direction and amendments.

### Market performance metrics enhanced

During 2007, we provided the following market performance metrics: the first edition of the quarterly long-term adequacy metrics including new generation status and retirements, reserve margin, supply cushion and two-year probability of supply adequacy shortfall; and implementation of a new seven-day, short-term supply adequacy report.

We are also developing the following metrics:

- ▶ preliminary market performance metrics to be used for the six-month review of the quick hit rules including merit order stability and price impacts related to TMR price reconstitution;
- ▶ new metrics to monitor the supply cushion, wind capacity utilization, transmission congestion and other price fidelity metrics; and,
- ▶ the hourly offer control test prototype, which is an integral part of the overall market power mitigation framework being advanced by the DOE.

In addition, we report numerous market metrics that provide insight into the general performance of the Alberta market through the AESO's Annual Report.

We have developed a comprehensive plan to expand and modify market metrics and to introduce a systematic process to track, store and deliver information. Our plan also includes a process to identify and investigate market and/or price anomalies. The major components of the plan include modification or development of metrics for price fidelity, market stability, market power, supply adequacy and transmission adequacy. As new metrics are developed and tested, we will determine whether, or how, to improve visibility and thereby enhance fidelity of the price signal.

### Operating reserve market improvements

Our key objective with the operating reserve market improvements is to align the operating reserve market with the energy market so participants can optimize their offers across assets for energy and operating reserve products on a similar timeline. It is expected that convergence between the markets will improve efficiency, provide for greater opportunity to optimize assets across energy and reserve products, reduce errors associated with forecast and remove the AESO as the single buyer. Additionally, we are proposing changes to operating reserve products and settlement to address issues related to price signals in the market.

We published two discussion papers on the operating reserve market design initiative in the fourth quarter of 2007. The consultation process will be advanced in 2008 through a stakeholder working group. This is a multi-year initiative with consultation likely to continue throughout 2008 followed by design and implementation in 2009 and 2010.



*We have a comprehensive plan to modify and expand the market performance metrics available to the marketplace.*

## Budget review process: accountability and transparency

Confidence in the marketplace is partly a function of how stakeholders perceive the AESO in the performance of its duties and responsibilities. In terms of financial accountability and transparency, we have continued to enhance our consultative stakeholder process related to our corporate strategy and business plan, referred to as the Budget Review Process (BRP). The process provides for a first level of prudence review and input. Our approach involves presenting the AESO's strategic objectives and outlining key business priorities and related financial budgets.

The BRP is in alignment with the amended Transmission Regulation issued in April 2007. The regulation authorizes the AESO Board to approve its own costs (general and administrative, capital and other industry costs), line loss costs and ancillary services costs. As part of the approval process the AESO must engage with and consult with stakeholders. The BRP replaces the historical EUB approval process.

We also developed a prioritization process where AESO projects are categorized on the basis of priority. A project is deemed to be a priority based on a comprehensive evaluation process. As the AESO's list of projects change, the list of priority projects is reviewed to determine which projects will be added, continued or deferred.

During the 2007 process, we provided stakeholders with business priorities and budgets for 2008 and 2009 for comment. As part of the BRP in 2006, stakeholders advised the AESO that they saw merit in a multi-year budget that contained an accountability framework.

The primary benefits from using a multi-year review and budget process include:

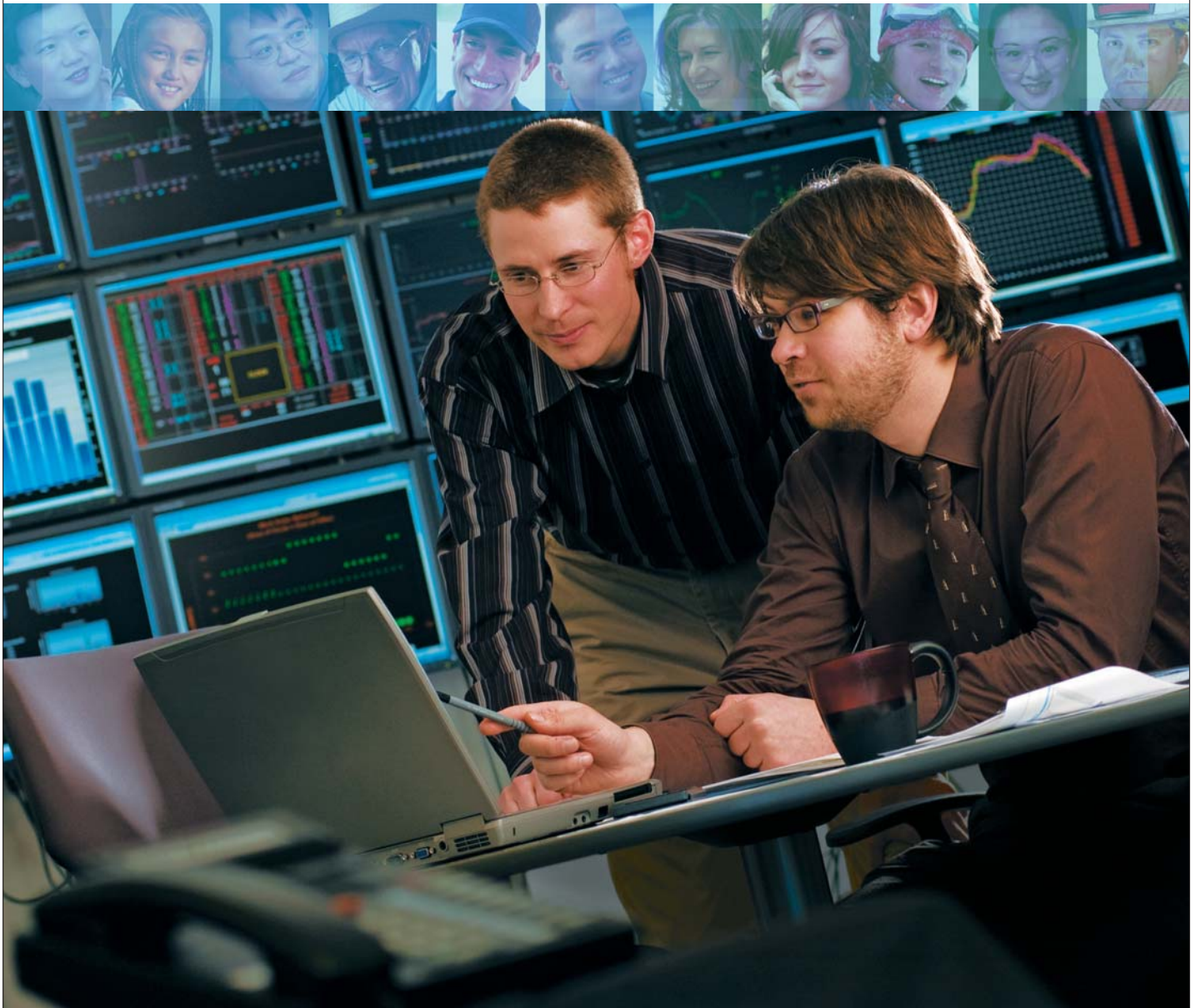
- ▶ enables cost stabilization, certainty and clarity for stakeholders, for multiple years;
  - ▶ provides visibility of our business priorities over a longer period of time; and,
  - ▶ achieves process efficiencies, for both stakeholders and the AESO, by reducing the annual budget review and approval time requirements.
- The AESO will continue to provide transparent and timely financial reporting to ensure success of the process.

In the unlikely event that an unreasonable expenditure occurs, we introduced a cost accountability framework. The purpose of the framework is to provide guidance to our Board, management and employees that we are prudently conducting our activities and expenditures.

The BRP continued to be a fully transparent process with written documentation and stakeholder comments posted on our website for stakeholders to view and make further comment. We believe the process achieved the goal of working with stakeholders to develop a comprehensive business planning document that provides a common understanding of expected deliverables in 2008 and 2009. We will continue to work with stakeholders to enhance the current process.

To view our most recent business plan, visit our website at [www.aeso.ca](http://www.aeso.ca) and follow the path: About AESO > Our Business > Business Plan and Budget > 2008 & 2009 Business Priorities and Budget.

# Alberta Wholesale Market Statistics





## 2007 marks continued growth

The Alberta wholesale electricity market saw continued growth in 2007; both power consumption and installed generation capacity increased during the year. The integration of wind power in Alberta's electricity market grew 37 per cent and supplied approximately 2.1 per cent of the total energy consumed in Alberta. Trade with other jurisdictions by means of the B.C. and Saskatchewan (Sask.) interties saw over 5,000 hours when the hourly intertie utilization was above 80 per cent, up approximately 55 per cent over the previous year. As the market continues to grow and meet the needs of Alberta, enhancements in how the market operates must be considered. Late in 2007, new market rules were implemented to address the Alberta Department of Energy's Electricity Policy Framework refinements issued in June 2005. A review of these new rules will take place in 2008. With continued growth in 2007, we expect to see increases in supply and demand, and further development of market rules and policies in 2008.

### Price summary statistics from 2000 to 2007

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

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

### Pool price down 17 per cent

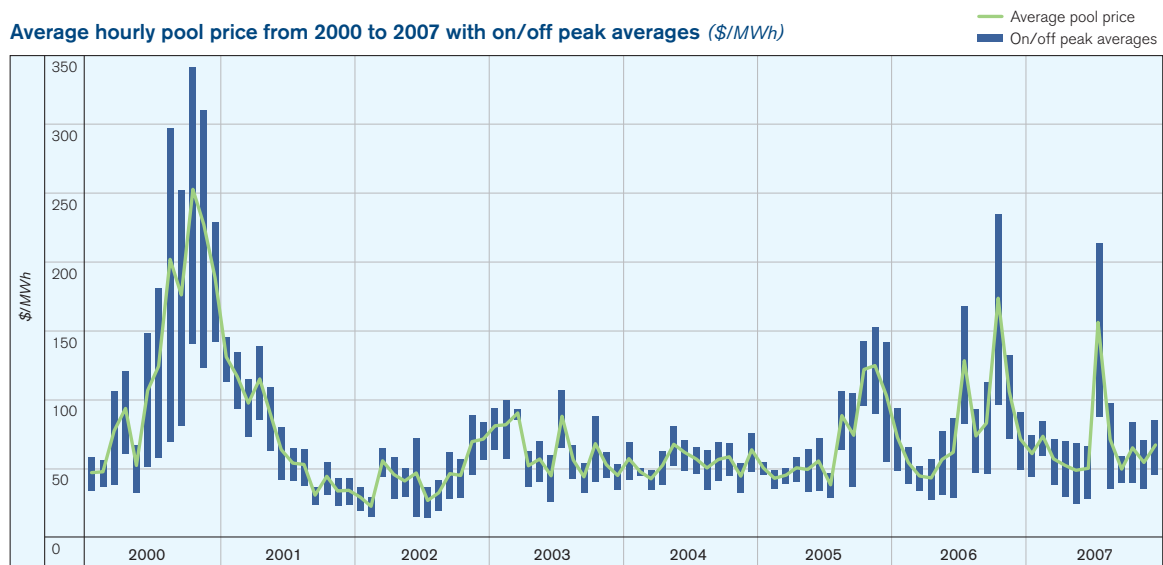
Alberta's competitive wholesale market electricity prices fluctuate based on supply and demand principles. During times of energy surplus, prices decrease, and during times of tight energy supply, prices increase. The wholesale electricity price, known as the pool price, ranges from \$0 per megawatt hour (MWh) to \$1,000/MWh.

In 2007, the Alberta wholesale pool price averaged \$66.95/MWh, decreasing 17 per cent from 2006. Lower monthly prices due to increased production from lower-cost generators in the last five months of 2007 when compared to 2006, is the primary reason for the decrease in 2007 annual pool price. On-peak and off-peak pool price averaged \$86.61/MWh and \$41.86/MWh, respectively for the year. The monthly average pool price of \$155.74/MWh in July made the largest contribution to the annual pool price. Hot weather in July pushed the demand for power to a new summer peak of 9,321 megawatts (MW). The higher temperatures also reduced the ability of generators to produce at full capacity, since both coal-fired units, and natural gas-fired units perform less efficiently in hot weather. These factors created a tight supply/demand balance which caused July prices to settle well above the annual average.

With the exception of the high July pool price, the year saw relatively stable monthly average prices, ranging from \$48.37/MWh to \$73.38/MWh. The month of May had the lowest monthly average pool price of \$48.37/MWh. Strong production from lower-priced, coal-fired and hydroelectric generation were the main drivers for the low May prices. Average off-peak price for the month was \$23.75/MWh, and on May 6 there were two hours when the price was \$0/MWh. These zero dollar hours were caused by low demand, near full coal-fired generation production, moderate wind generation, and a minimal incentive to export due to low power prices in the Pacific Northwest.

Wind generation is non-dispatchable and thus offers into the market at zero dollars. As such, the pool price tends to be lower when there is a significant amount of wind power production. In this respect, the increased amount of wind generation on the Alberta Interconnected Electric System (AIES) in 2007 has had a downward effect on wholesale pool prices in Alberta.

**Average hourly pool price from 2000 to 2007 with on/off peak averages (\$/MWh)**



#### **Small increase in overall energy consumption**

In 2007, Alberta consumed over 69,660 gigawatt hours (GWh) of electricity. This represents a 0.42 per cent increase over 2006 energy consumption, which is the smallest growth in Alberta's energy consumption this decade. Industrial plant closures in Fort Saskatchewan, Edmonton and Bruderheim, and maintenance activities at a Fort McMurray plant, were the main causes offsetting load growth in energy for the year. Despite the industrial plant closures, Alberta had continued growth in residential demand and demand in the Fort McMurray region. This demand growth contributed to a new Alberta Internal Load (AIL) peak of 9,701 MW on December 3, 2007. Another record of 9,710 MW was set on January 28, 2008. Electricity consumption in Alberta has grown by 29 per cent since 2000 with a year-over-year average load growth of 3.2 per cent per year over the last five years.

## Demand statistics from 2000 to 2007

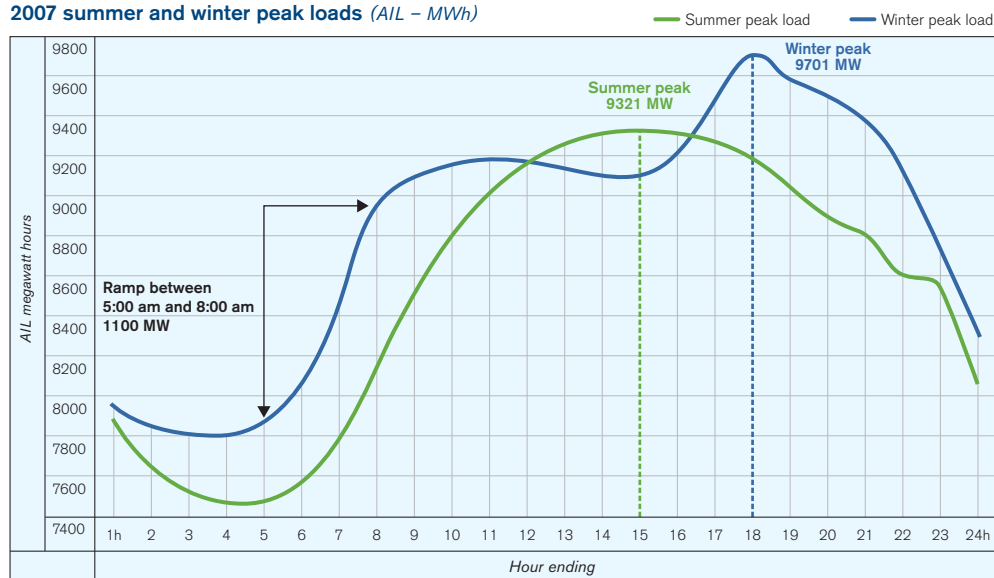
<i>Alberta internal load (AIL)</i>	2000	2001	2002	2003	2004	2005	2006	2007
Total AIL (GWh)	54,053	54,464	59,428	62,714	65,260	66,267	69,371	<b>69,661</b>
Average hourly load (MW)	6,154	6,217	6,784	7,159	7,429	7,565	7,919	<b>7,952</b>
Maximum hourly load (MW)	7,785	7,934	8,570	8,786	9,236	9,580	9,661	<b>9,701</b>
Minimum hourly load (MW)	4,999	5,030	5,309	5,658	6,017	6,104	6,351	<b>6,440</b>
Year-over-year load growth	–	0.76%	9.11%	5.53%	4.06%	1.54%	4.69%	<b>0.42%</b>
Load factor	79.0%	78.4%	79.2%	81.5%	80.4%	79.0%	82.0%	<b>82.0%</b>

## Load and seasonal supply/demand balance

### Weather affect on seasonal load profile

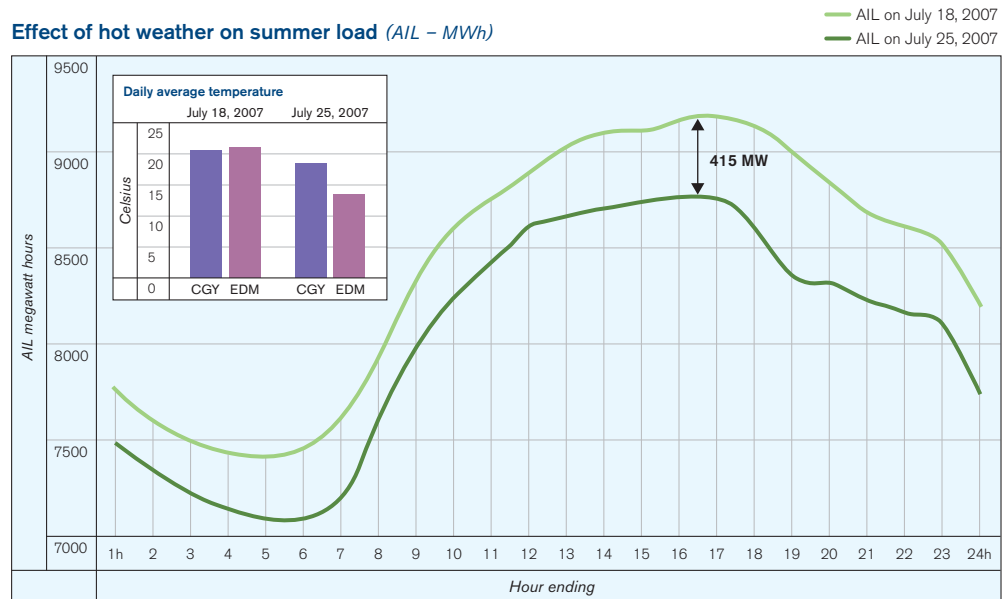
The demand for electricity follows different profiles depending on the season. Major factors that impact the load profile are the heating and cooling loads, and the lighting load. The winter demand profile has a sharp increase in the morning, a flat load during the afternoon and a large increase in the early evening before dropping off later in the evening. The summer profile has a steady increase in the morning until mid-afternoon and a steady drop into the evening. Temperature has a large impact on both the summer peak load and the winter peak load. During hot summer days and cold winter days, load can be substantially higher.

### 2007 summer and winter peak loads (AIL – MWh)



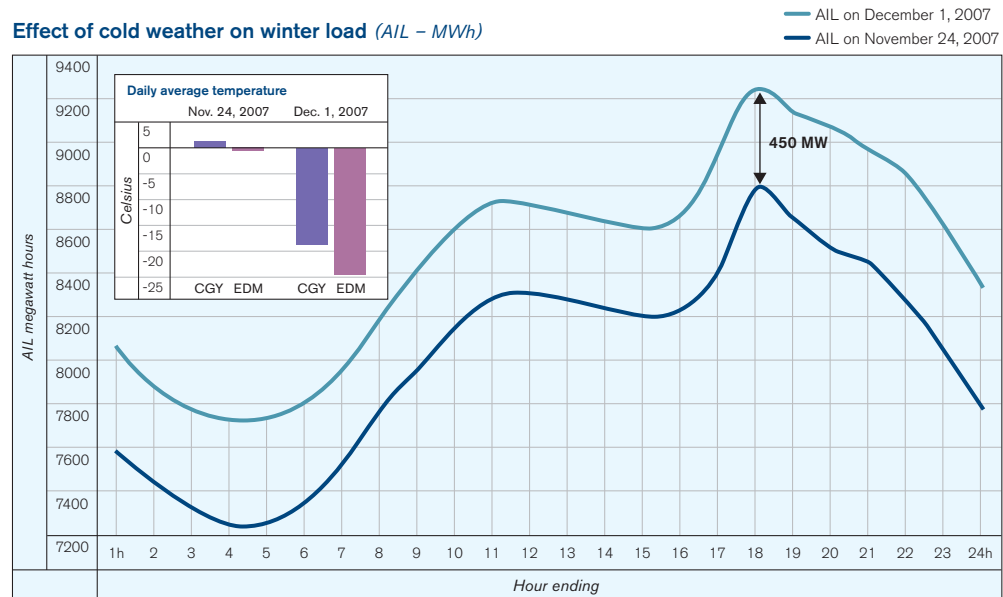


### Effect of hot weather on summer load (AIL – MWh)



On July 18, 2007, the average temperature in Calgary and Edmonton was 21.9°C and on July 25 the average temperature was 15.4°C. The average difference in load was 395 MW.

### Effect of cold weather on winter load (AIL – MWh)

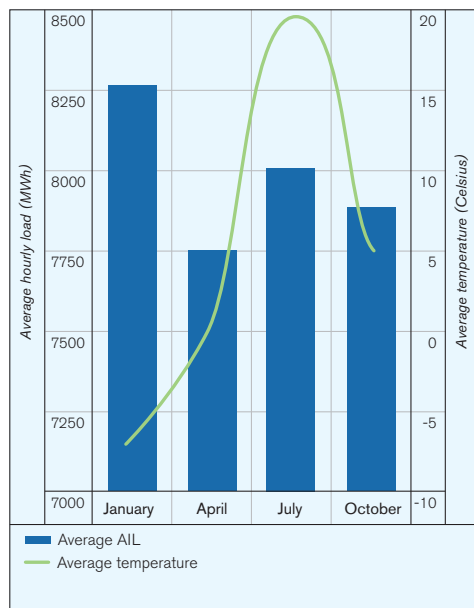


On December 1, 2007, the average temperature in Calgary and Edmonton was -21°C and on November 24 the average temperature was 1°C. The average difference in load was 471 MW.

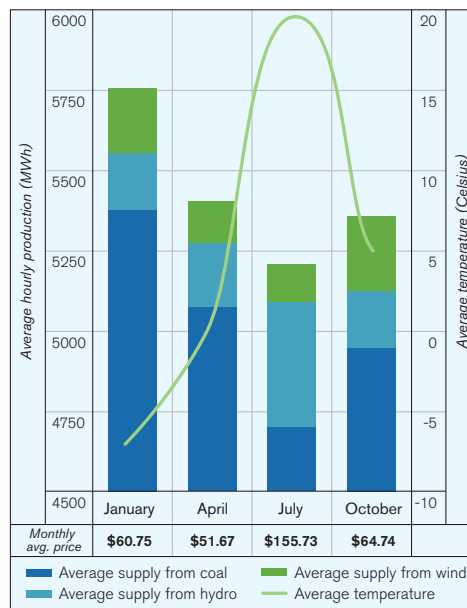
### Weather and maintenance affects supply

Not only is demand impacted by the season, but supply also has seasonal profiles. Coal-fired, hydroelectric, and wind generation have traditionally provided different volumes of energy depending on the season. The charts below show the average hourly production by fuel type, average temperature, and average load. The analysis shows that in the summer of 2007, coal-fired generation produced less energy than during the winter months. This is due to a combination of factors including planned maintenance during the summer, decreased ability to generate due to the hot weather and daily load levels. Hydroelectric generation typically produces more electricity after winter and during spring run-off. Wind generation, like coal-fired power, traditionally produces less power during the summer months. The reduction in lower-priced generation can result in increased prices during summer months, even though loads are somewhat lower than in the winter.

2007 average hourly load by season



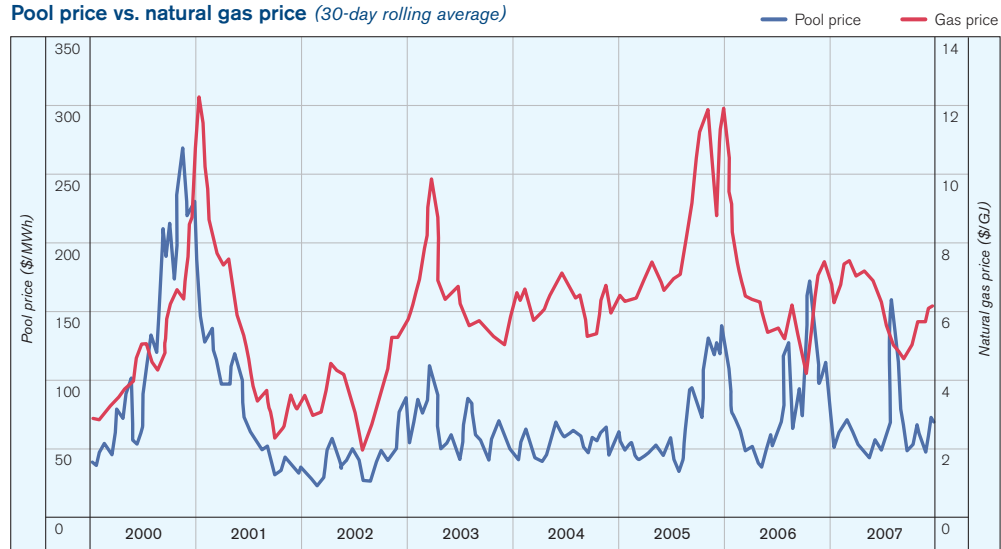
2007 average hourly supply by fuel by season



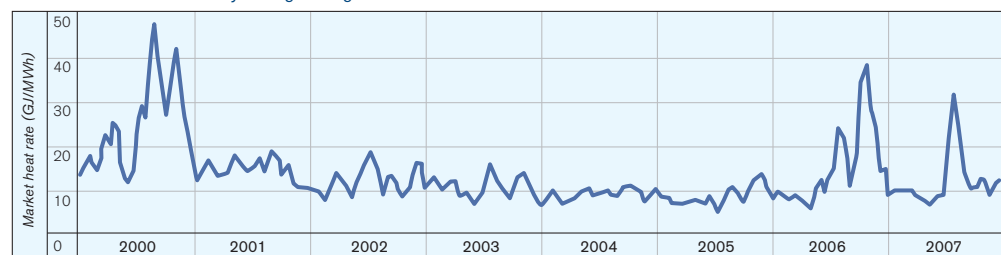
### Pool price reflective of fuel costs

The Alberta pool price is determined by the highest priced generator that is needed to meet the demand for electricity. Generators submit hourly offers detailing the amount of energy that they will provide at a certain price to the AESO. 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's system controllers dispatch generating units until the demand requirement is satisfied. The price at which generators offer their energy into the market changes as the cost of the generator's fuel source changes. Natural gas is one of the primary fuel costs for generators in Alberta. Therefore, as the price of natural gas increases we expect the price of electricity to increase. The chart below shows the historic relationship between electricity prices and natural gas prices, and the annual average market heat rate. In general, the market heat rate is the relationship between electricity prices and fuel cost. Market heat rate is determined by dividing the pool price by the price of natural gas. The market heat rate in 2007 was lower than 2006, but higher than 2004 and 2005. This shows that even though 2007 pool prices were lower than in 2005, after factoring in natural gas prices, 2007 was more likely to be profitable for natural gas generators.

**Pool price vs. natural gas price (30-day rolling average)**



**Market heat rate (30-day rolling average)**



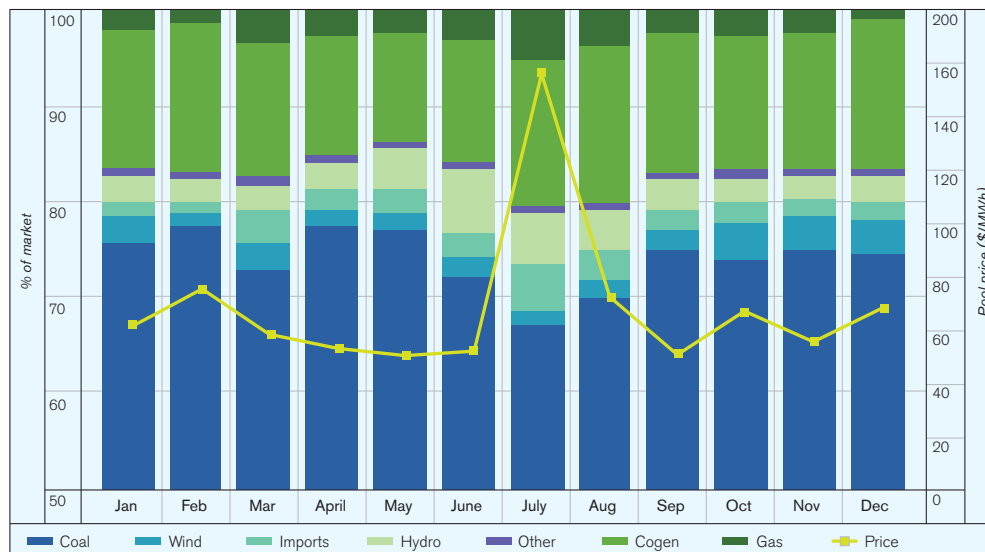
**Annual market heat rate**

(GJ/MWh)	2000	2001	2002	2003	2004	2005	2006	2007
Market heat rate	24.94	14.19	11.58	10.08	8.79	8.23	13.99	11.45



The chart below shows the relationship between energy production by fuel type and electricity price in 2007. Lower-priced electricity is from coal, wind and hydroelectric energy. When there is a significant volume of production from these fuel types we expect electricity prices to be lower. In April and May 2007 there was significantly more energy from lower-priced generators, which resulted in a pool price that was lower than the annual average pool price. During months where higher-priced natural gas generators are producing more energy, one would expect that electricity prices would be higher. This was apparent during the month of July, when there were scheduled outages and forced derates of coal-fired units.

**Per cent of market supplied by fuel type**



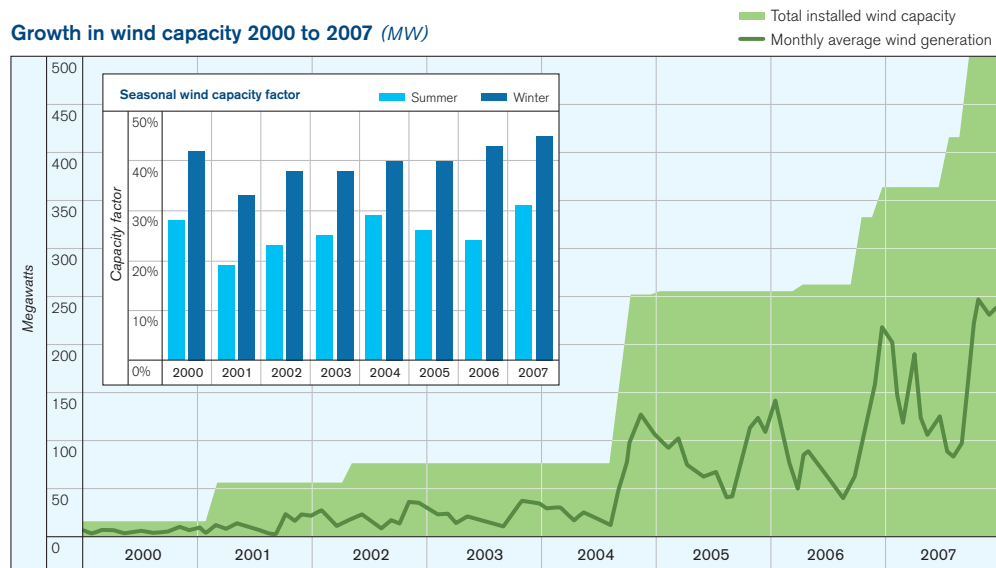
### Alberta integrates more wind

Wind power is an important and growing part of the generation mix of the AES. The AESO is collaborating with stakeholders to develop policies and standards to facilitate this growing source of energy. In 2007, the AESO worked collaboratively with stakeholders to develop the Market and Operational Framework for Wind Integration, which replaced the temporary 900 MW wind generation threshold.

The following graph illustrates the growing capacity of wind power and the average amount of wind generated on a monthly basis. Since 2000, the total transmission connected capacity for wind in Alberta has grown from approximately 20 MW to 497 MW, with 135 MW of additional wind capacity added in 2007. There is now about enough wind capacity to power three cities the size of Red Deer (population of about 86,000). In 2007, there was about 1,450 GWh of wind energy produced. This represents about 2.4 per cent of the energy provided by the market, or about 2.1 per cent of the total energy consumed in Alberta.

The variable nature of wind power results in fluctuating levels of wind generation available to the market. The aggregate capacity factor for wind power facilities compares the total energy production over a period of time with the amount of power the plant would have produced 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 39.5 per cent in 2007. The previous year's annual capacity factor was 33.7 per cent. Part of the increase in the 2007 annual capacity factor over the prior year is the significant addition of wind power facilities late in the year when wind generation tends to be stronger. As the AESO adds more wind generation to the AES, the AESO will continue to monitor wind power characteristics, the amount of wind energy produced, and wind capacity factors. Wind generation demonstrates a strong seasonal pattern with capacity factors being higher in winter (November – April) than in summer (May – October).

**Growth in wind capacity 2000 to 2007 (MW)**

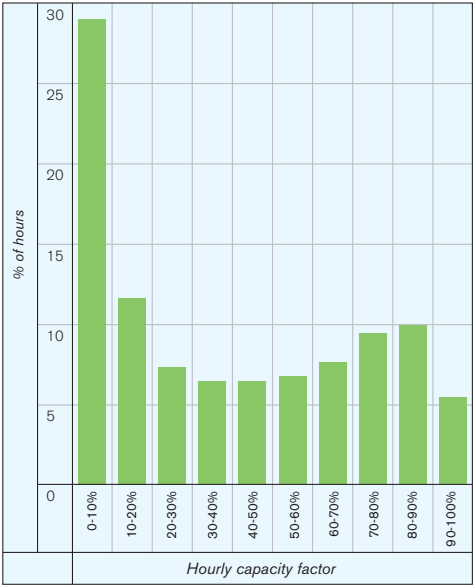


2007 total installed capacity = 497 MW

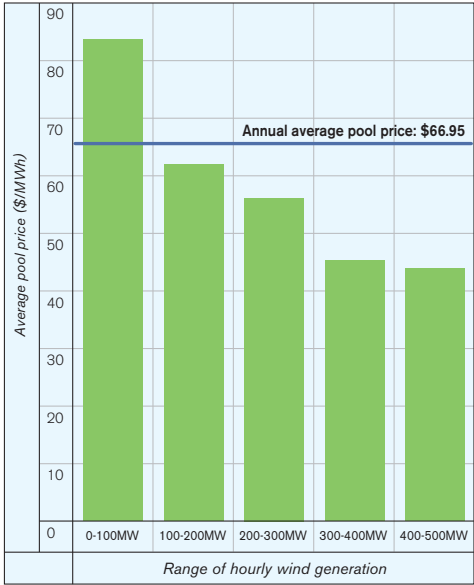
The 2007 hourly wind capacity factor chart illustrates the percentage of hours when the wind capacity factor was in certain ranges. While wind power frequently generated an hourly capacity factor of less than 10 per cent, wind power facilities in Alberta generated an hourly capacity factor of more than 70 per cent for over one quarter of the year. 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.

Wind generation is non-dispatchable and thus offers into the market at zero dollars. As such, the pool price tends to be lower when there is a significant amount of wind power production. This is due to zero dollar wind generation displacing higher-priced generation. In other words, with demand constant, as wind generation increases, supply and demand is kept in balance by dispatching down generation that is offered to the energy market merit order. The 2007 wind vs. pool price chart illustrates 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 average annual price.

**2007 hourly wind capacity factor**  
(% of hours)



**Wind vs. pool price**  
(Average pool price for varying amounts of wind)



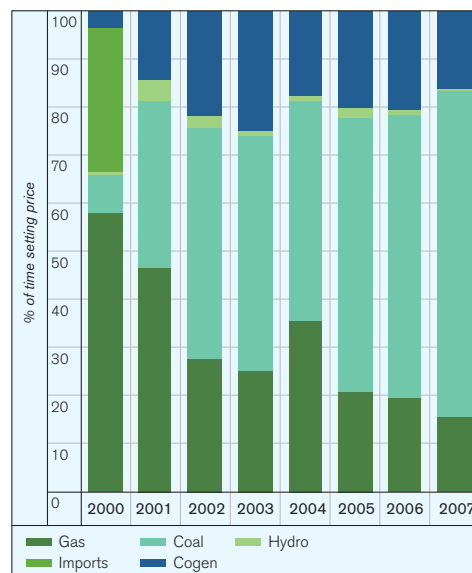


### Coal continues to provide a majority of Alberta's energy

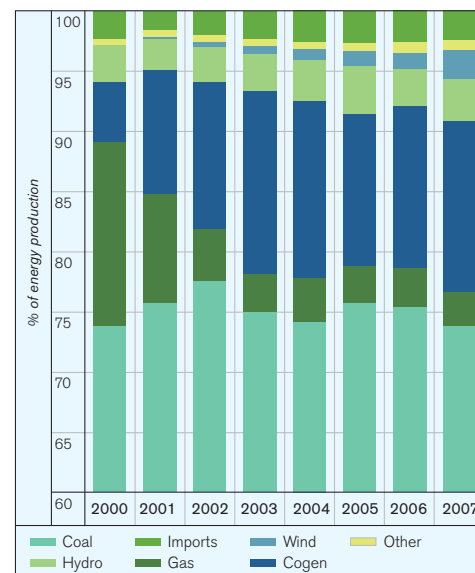
Coal-fired generation continues to provide the market with a majority of the required energy, accounting for almost 74 per cent of the required market energy. This is down slightly from the previous year, when coal-fired generation provided about 75 per cent of required market energy.

In 2007, we saw an increase in the amount of time that coal-fired units set the wholesale pool price. They set the price approximately 68 per cent of the time compared to 59 per cent of the time in 2006. Dedicated natural gas (gas-fired units that produce electricity only for profit) and natural gas cogeneration units (gas-fired units that provide energy or steam for on-site industrial processes) set the price for most of the remaining time. Hydroelectric units set prices only a small amount of the time, primarily during high price periods.

**Price setter by fuel type**  
(% of time setting price)



**Energy production by fuel type**  
(% of energy production)



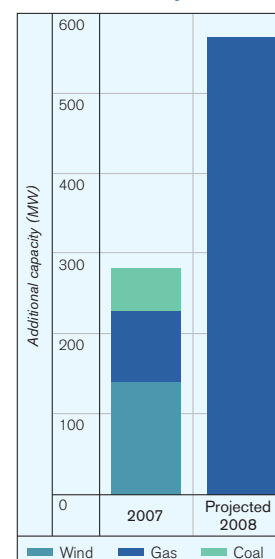
### Over 500 MW of new supply expected in 2008

As a result of market signals indicating the need for new generation, 2007 saw an increase in overall generation capacity in the province. In total, over 250 MW of wind, natural gas, and coal generation was added to the system. This new capacity helps to serve the continuing growth in electricity demand with the latest technology. In the coming year, additional gas-fired peaking generation and industrial generation is expected to come online. The peaking generation will provide energy during times of tight supply/demand balance while the industrial generation will provide power for the expected growth in various industries. Overall, this generation is expected to provide approximately 575 MW of capacity. New plants expected to come online in 2008 include Long Lake, Horizon Project, Clover Bar #1 and #2, Shell Caroline, Valleyview and Christina Lake. With the exception of the Shell Caroline plant, which is located in the central/south area, all these plants are located in the northern part of the province.

### Transfer capability of interties improves in 2007

Alberta benefits from transmission interties with B.C. and Sask. These interties allow energy to be imported during times of tight supply and exported during times of energy surplus, benefiting all connected jurisdictions. Typically, Alberta exports energy during the evening and imports energy during the day. In 2007, Alberta continued to be a net importer of electricity with net imports of about 494,000 MWh. Export volumes increased in 2007 when compared to 2006 levels. This increase can be attributed to higher transfer capability on the interties.

New additions by fuel



### Import and export statistics from 2000 to 2007

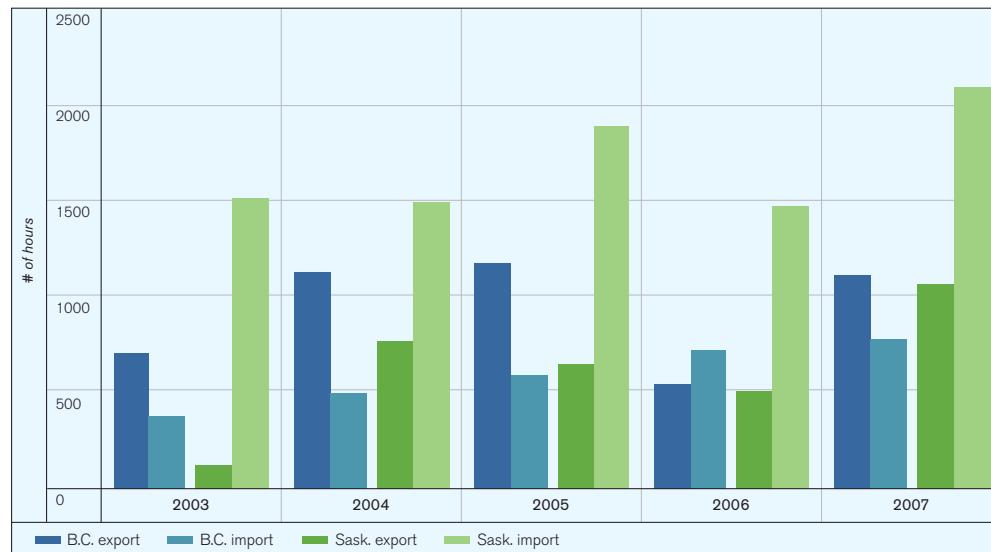
<i>Intertie statistics (MWh)</i>	2000	2001	2002	2003	2004	2005	2006	2007
Imports on B.C. intertie	564,238	232,052	895,753	898,717	1,073,471	1,070,848	1,101,207	<b>927,108</b>
Imports on Sask. intertie	742,704	676,130	239,406	428,949	418,267	463,726	415,828	<b>540,113</b>
<b>Total imports</b>	<b>1,306,942</b>	<b>908,182</b>	<b>1,135,159</b>	<b>1,327,666</b>	<b>1,491,738</b>	<b>1,534,574</b>	<b>1,517,035</b>	<b>1,467,221</b>
Year-over-year growth	—	-30.51%	24.99%	16.96%	12.36%	2.87%	-1.14%	<b>-3.28%</b>
Exports on B.C. intertie	797,092	1,974,107	465,939	1,194,264	968,434	987,581	460,050	<b>885,551</b>
Exports on Sask. intertie	27,166	63,388	105,337	32,903	92,940	50,493	29,415	<b>87,666</b>
<b>Total exports</b>	<b>824,258</b>	<b>2,037,495</b>	<b>571,276</b>	<b>1,227,167</b>	<b>1,061,374</b>	<b>1,038,074</b>	<b>489,465</b>	<b>973,217</b>
Year-over-year growth	—	147.19%	-71.96%	114.81%	-13.51%	-2.20%	-52.85%	<b>98.83%</b>
<b>Net yearly imports (exports)</b>	<b>482,684</b>	<b>(1,129,313)</b>	<b>563,883</b>	<b>100,499</b>	<b>430,364</b>	<b>496,500</b>	<b>1,027,570</b>	<b>494,004</b>

### Intertie utilization on the rise

The Available Transfer Capability (ATC) is the amount of electricity that can flow on the interties. In 2007, the maximum import and export ATC values on the B.C. intertie were 675 MW and 735 MW, respectively. On the Sask. intertie the maximum import and export ATC levels were 153 MW and 60 MW, respectively. The chart below shows a historic analysis of the number of hours when the interties were at least 80 per cent utilized. Utilization is both the amount of hourly scheduled flows and the amount of reserves provided by the interties, divided by the hourly ATC. In 2007, the frequency of highly utilized hours on both interties, for imports and exports, was higher than the previous year. The frequency that the intertie with B.C. has been highly utilized for imports has increased steadily from 379 hours in 2003 to 788 hours in 2007.

### Number of hours the interties are highly used

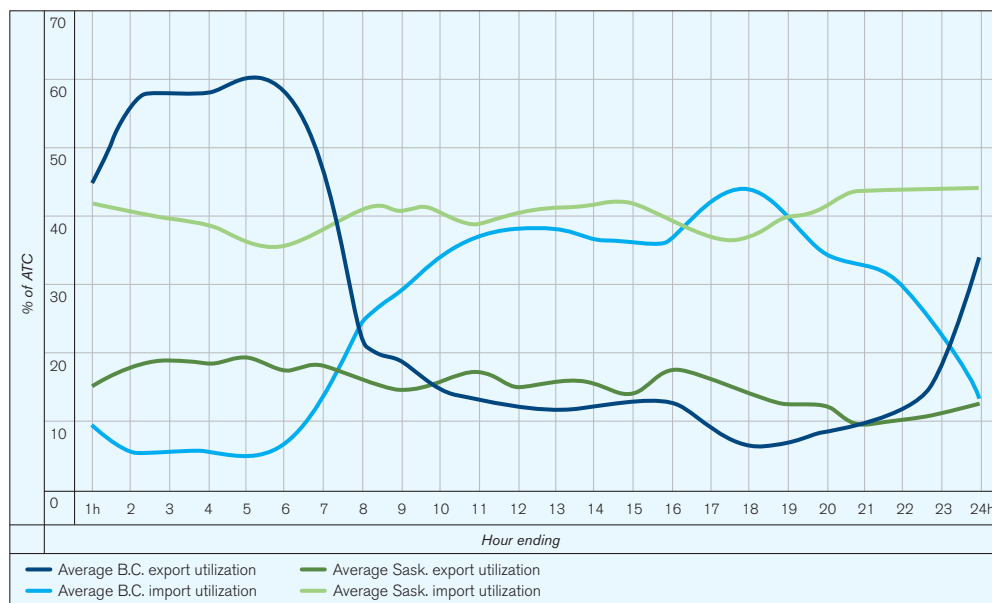
(Highly used = 80% or greater utilization of the intertie ATC)





Utilization of the interties is dependent on the time of day. This is especially true for the intertie with B.C. The following figure illustrates the flow of Alberta's imports and exports during all hours of the day. The average import utilization on the B.C. intertie closely follows the load shape in Alberta, ramping up during the morning hours and remaining low overnight when Alberta is exporting. Conversely, the average export utilization on the B.C. intertie follows an inverse relationship to Alberta's load shape, with strong export utilization in the evening and low utilization during peak load hours.

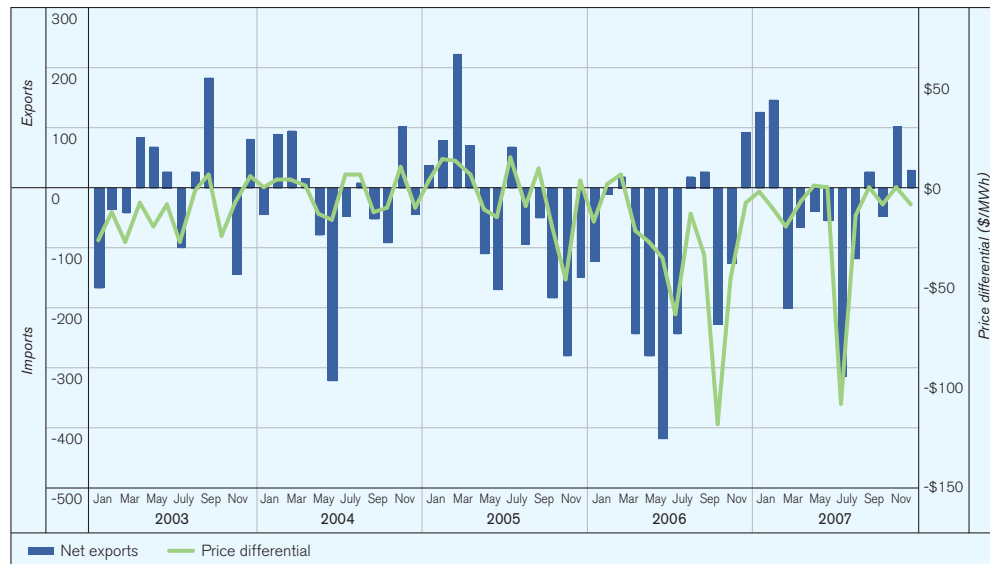
**Average intertie utilization in 2007 by hour ending**



### Price drives trade between Alberta and Pacific Northwest market

The Alberta market is linked with other jurisdictions by way of its transmission interties with B.C. and Sask. The largest connection is with the Pacific Northwest via the intertie with B.C. Using the Mid-Columbia (Mid-C) electricity price as the primary price signal in the Pacific Northwest, the chart below shows the relationship between flows on the B.C. intertie and electricity prices in Alberta and the Pacific Northwest. The analysis only incorporates the flow of energy that occurs when the price differential between Mid-C and the pool price is greater than \$10/MWh, as it is unlikely that price differentials smaller than this would cause energy flows. 2007 saw a continued strong relationship between intertie flows and the Alberta/Mid-C price differential. In particular, strong imports into Alberta occurred in July when there was a large differential between the two jurisdictions. The months of January, February and November saw relatively large export flows. During this time there was a tight spread of prices between the Pacific Northwest and Alberta.

Mid-C/pool price differential (\$/MWh)



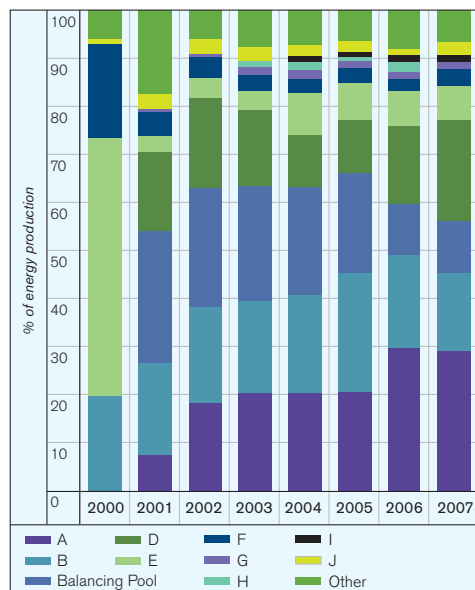
### Little change in generation production by company

In 2007, there was little change in ownership and control of generation and little change in overall energy production by company. This is a significant shift from 2006 which saw major changes in the amount of generation owned or controlled by firms. There continues to be five or six companies that supply most of the electricity in Alberta.

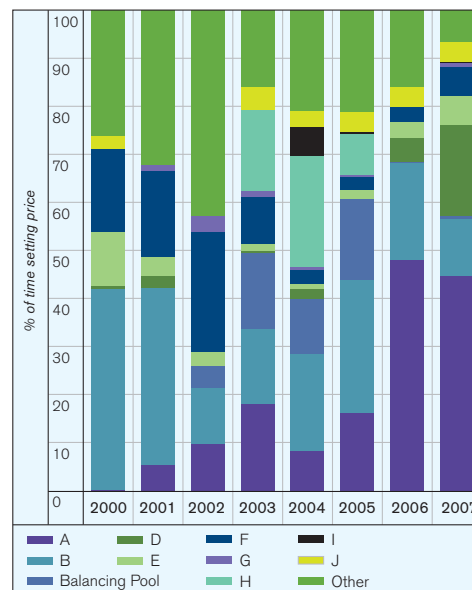
### More diversity in companies setting price

In 2007, there continued to be a single participant setting price proportionally more than other participants; setting price over 40 per cent of the time. Overall in 2007, there was more diversity in which companies set price versus 2006.

**Energy production by company**  
(% of energy production) (MWh)



**Price setters by company**  
(% of time setting price)





### Prices for reserves related to pool price

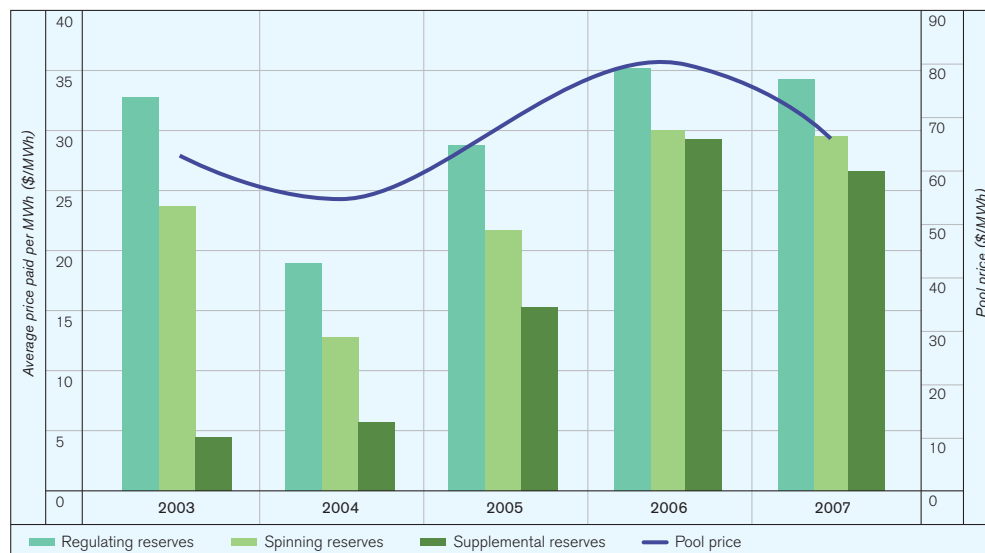
The AESO procures operating reserves for the AIES to ensure ongoing reliability of the transmission system. There are three types of operating reserves; regulating reserves, spinning reserves and supplemental reserves, each of which has two products; active or standby. The reserves are bought from either the ancillary services exchange or through over-the-counter (OTC) contracts. The majority of operating reserve offer prices are indexed to the pool price.

Since 2003, there has been a positive correlation between pool price and the average price paid for regulating and spinning reserves. For supplemental reserves, this correlation in 2003 and 2004 does not exist as a result of the amount of supplemental reserves provided by hydro units. In August 2004, the contract for offering hydro power purchase arrangement energy was amended, which subsequently resulted in higher costs for supplemental reserves.

### Active operating reserves price statistics

Average price/MWh (\$/MWh, rounded)	2003	2004	2005	2006	2007
Pool price	63	55	70	81	<b>67</b>
Active regulating reserves	33	19	29	35	<b>34</b>
Active spinning reserves	24	13	22	30	<b>30</b>
Active supplemental reserves	4	6	15	29	<b>26</b>

### Historic active operating reserves



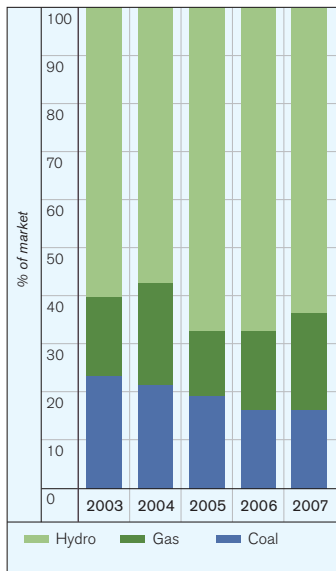
### Gas-fired units claim higher share of active supplemental reserves

Over the last five years, hydroelectric generators have consistently dominated as the main provider for active regulating reserves. In 2007, over 60 per cent of regulating reserves were provided by hydroelectric generators, while approximately 20 per cent and 15 per cent were provided from gas-fired and coal-fired generators, respectively.

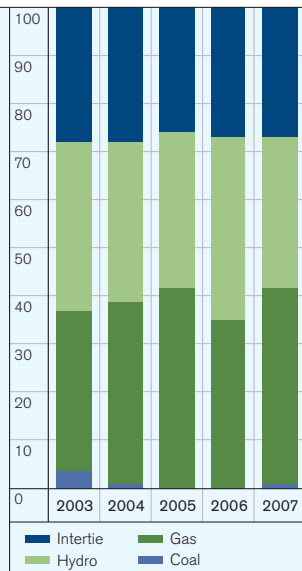
Active spinning reserves have been mainly provided from natural gas-fired and hydroelectric generators, and the B.C. intertie. The market share of active spinning reserves by fuel type has seen little change from 2003 to 2007.

There has been a substantial increase in the volume of active supplemental reserves provided by natural gas-fired generators in the last five years. This has been offset by a significant reduction in active supplemental reserves provided by hydroelectric generators due to the previously mentioned amendment to the hydro power purchase arrangement. In 2003, natural gas-fired generators supplied only three per cent of the required active supplemental reserve. This increased to approximately 45 per cent of the required volumes in 2007.

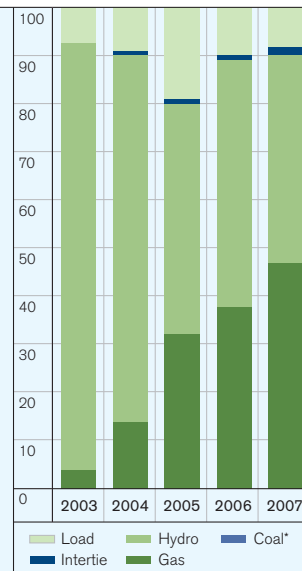
**Market share of active regulating reserves by fuel**  
(% of market)



**Market share of active spinning reserves by fuel**  
(% of market)



**Market share of active supplemental reserves by fuel**  
(% of market)



\*Coal is below 1% in all years.

# Corporate Governance



## Overview

Governance is a philosophy, an approach and a process. Governance reflects the culture of an organization. The AESO Board has developed its governance structure, practices and style, which are embedded within the organization's vision, mission, beliefs and values. Governance encompasses both internal and external business activities and relationships.

Fundamental to governance is the clarity it brings to decision making, accountability and the roles of the 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.

## Board of Directors

### *Responsibility*

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 discusses and approves the strategic plan. On an ongoing basis, the AESO Board conducts financial oversight of all 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 on our website at [www.aeso.ca](http://www.aeso.ca) and follow the path: About AESO > Our Company.

### *Independence*

The AESO is governed by the AESO 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 Act*. Each Member is independent of any person having a material interest in the Alberta electric industry. In accordance with the bylaws, the AESO Board must recommend to the Energy Minister individuals to be appointed as an AESO Board Member and may recommend to the Minister an individual to be designated as Chairman. 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, technology and government, and various professions, including regulatory, engineering and accounting. The following are the names of the current AESO Board Members:

AESO Board Members	AESO Board Member Since	Current AESO Board Position	Committee Members
Harry Hobbs	2004	Chairman	Audit, HRCG*
Bill Burch	2003	Vice-Chair	Chair Audit, HRCG*
Ron George	2003	Member	HRCG*
Nancy Laird	2003	Member	Chair HRCG*
Hugh Fergusson	2007**	Member	HRCG*
Robert McClinton	2007**	Member	Audit
Walter Nieboer	2007**	Member	Audit
Monica Sloan	2007**	Member	Audit

\* HRCG (Human Resources, Compensation and Governance Committee)  
\*\* Appointed AESO Board member effective December 1, 2007

**AESO Board Committees**

The AESO Board has structured two standing committees that meet on a quarterly basis and 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, the systems of internal controls, the 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 (HRCG)**

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, Chief Executive Officer performance, officer selection, and human resources programs (including salary planning and incentive design), current human resources practices and maintenance and enhancements to corporate governance practices.

**Governance practices**

The AESO looks to private, public and not-for-profit sectors of industry to ensure it is using best business practices in all of its business dealings. The following are pertinent governance practices the AESO Board utilizes to ensure sound corporate governance exists within the AESO.

**Code of Conduct**

It is a policy of the AESO that all employees annually review the AESO's Code of Conduct and confirm compliance/non-compliance with it and agree to abide by it. There are no exceptions to signing and abiding by the Code of Business Conduct. New employees are required to review and agree to abide by it on their first day of employment. The AESO Board (or members of the AESO) are also bound by the AESO Members Code of Conduct outlined in the bylaws.

**Strategic planning**

The AESO's strategic plan provides organizational direction for the development of corporate, departmental and individual plans and goals for 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 for the AESO are established.

**Performance management**

The AESO establishes goals to be achieved at the corporate level. The corporate goals are established annually by AESO executive based on the business priorities set out in the strategic plan and business plan. The AESO Board provides oversight in establishing, approving and setting of the goals as well as corporate milestones and metrics.

### *Performance reporting*

The 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 which are at risk of not being achieved. For those goals that are at risk of not being met, strategies are developed or altered in order 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 senior management and the AESO Board Audit Committee, which detail identified risks, their status, and related mitigation strategies. The AESO prioritizes these risks and incorporates them into the annual goal-setting process to ensure that they are mitigated to the fullest extent possible. Risk mitigation also 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 AESO 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; and,
- ▶ compliance with laws and regulations.

### *External audits, reviews and procedures*

Operating audits, reviews and procedures are performed to ensure 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, and the ultimate review and approval of the audited financial statements by the AESO Board.

### **AESO Executive**

The AESO Board is responsible for appointing the Chief Executive Officer. The Chief Executive Officer shall appoint other officers as required. Such appointment requires the ratification of the AESO Board.

The AESO Board has structured the organization with an executive team who run the business and develop corporate practices, including governance practices, to meet best business practices. The current executive team is as follows:

<b>Dale McMaster</b>	<i>President &amp; Chief Executive Officer</i>
<b>David Erickson</b>	<i>Senior Vice-President &amp; Chief Operating Officer</i>
<b>Todd Fior</b>	<i>Vice-President, Finance</i>
<b>Warren Frost</b>	<i>Vice-President, Operations &amp; Reliability</i>
<b>Heidi Kirrmaier</b>	<i>Vice-President, Regulatory</i>
<b>Neil Millar</b>	<i>Vice-President, Transmission</i>
<b>Cliff Monar</b>	<i>Vice-President, Market Services</i>
<b>Sandra Scott</b>	<i>Vice-President, Information Technology</i>
<b>Wayne St. Amour</b>	<i>Vice-President, Corporate Services</i>

# Board Members



*Standing, left to right*

Ron George  
Harry Hobbs  
Bill Burch  
Nancy Laird  
Walter Nieboer

*Seated, left to right*

Hugh Fergusson  
Monica Sloan  
Robert McClinton

**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 on the boards of Teague Exploration Inc., a private oil and gas company operating in Western Canada as well as 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*

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.

**Ron George***Member of the Human Resources,**Compensation and Governance Committee*

Dr. George (Ph.D.) has been a member of the AESO Board since 2003. He joined the Board of one of the AESO's predecessor companies in 1999. He has more than 40 years experience in the information technology business and works as a consultant, teacher, entrepreneur and mentor. He was previously executive-in-residence at the University of Calgary, Faculty of Management. Dr. George has served on the Board of Regents at Concordia University College in Edmonton and on the Board of Directors for Lutheran Life in Waterloo and numerous high-tech companies.

**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 energy trading and market portfolios, investment banking and information technology as well as futures trading. She is a Board member of United Way of Calgary and Hull Child and Family Services and a former Board member of Canadian Oil Sands Trust, Southern Alberta Institute of Technology, Alliance Pipeline and ProGas.

**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 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*

Ms. Sloan joined the Board in December 2007. She is Managing Director and CEO of Intervera Ltd., 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.

**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, 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, throughout England, Europe, U.S., Mexico, South America and New Zealand. 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 Electricity Supply Board International, (ESBI) Alberta Ltd. and as special Advisor to the Board of Directors of the Yukon Energy Corporation.



# Executive Team



*Seated, left to right*

Dale McMaster  
David Erickson  
Sandra Scott

*Standing, left to right*

Neil Millar  
Heidi Kirrmaier  
Cliff Monar  
Warren Frost  
Todd Fior  
Wayne St. Amour

**Dale McMaster***President & Chief Executive Officer*

As President and Chief Executive Officer Mr. McMaster is responsible for the AESO effectively carrying out its mandate to ensure the safe, reliable and economic operation and development of the AES and to operate the province's fair, efficient and openly-competitive wholesale electricity market. An electrical engineer, Mr. McMaster has more than 30 years of experience in power systems investment planning, operations, transmission system maintenance and electric utility management in Canada as well as abroad. Since 2003, Mr. McMaster has served at the AESO in the capacities of Chief Operations Officer and executive Vice-President of Operations & Reliability. Mr. McMaster was appointed to his current role in July 2005.

**David Erickson***Senior Vice-President & Chief Operating Officer*

Mr. Erickson is responsible for the AESO's strategic decision-making across all key operational areas. He has been active in the electricity industry for many years and served as Chief Financial Officer for the former Transmission Administrator of Alberta. His experience spans more than 20 years of international financial management and accounting expertise in the energy and electricity sectors. Mr. Erickson began serving as Chief Financial Officer for the AESO in 2003 and his responsibilities were expanded in 2005. He was appointed to his current role in February 2007.

**Todd Fior***Vice-President, Finance*

Mr. Fior is responsible for all financial management and accounting activities at the AESO. He has more than 16 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, procedures, 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. Mr. Frost is an electrical engineer with more than 30 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, which includes overseeing the consultation, design and implementation of the AESO's transmission tariff and other proceedings as regulated by the Alberta Utilities Commission. Ms. Kirrmaier brings extensive regulatory experience to her current role including previous responsibilities as Director, Regulatory Affairs and Manager, Rate Design and Forecasting at Aquila Networks Canada as well as 11 years with ATCO in a variety of regulatory roles. Ms. Kirrmaier was appointed to her current role in December 2005.

**Neil Millar***Vice-President, Transmission*

Mr. Millar is accountable for the strategic planning and timely development of Alberta's interconnected electric grid, including the development of the organization's 20-Year Outlook, 10-Year Transmission System Plan and individual Need 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***Vice-President, Market Services*

Mr. Monar is responsible for the design and operation of a fair, efficient and openly competitive electricity market, the development of market rules and the competitive procurement of ancillary services, consistent with Alberta's wholesale electricity market policy. Mr. Monar has 20 years of industry experience in energy trading and portfolio management, business development, engineering and project management. Since 2003, he has served as Director of Strategic Initiatives and Commercial Services for the AESO. Mr. Monar was appointed to his current role in February 2007.

**Sandra Scott***Vice-President, Information Technology*

Ms. Scott is responsible for the development, implementation and management of the information systems supporting the AESO. Her 20-year background in the energy sector includes consulting to a variety of companies in the areas of business and information technology strategic planning, program and project management, information architecture and implementation of business solutions. Ms. Scott was appointed to her current role in July 2006.

**Wayne St. Amour***Vice-President, Corporate Services*

Dr. St. Amour (Ph.D.) is responsible for the strategic direction of Human Resources, Stakeholder Relations/Corporate Communications and Customer Services. 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 his current position in October 2006.



## Financial Table of Contents

47

Management's Discussion and  
Analysis of Financial Condition  
and Results of Operations

58

Management's Responsibility  
for Financial Reporting

59

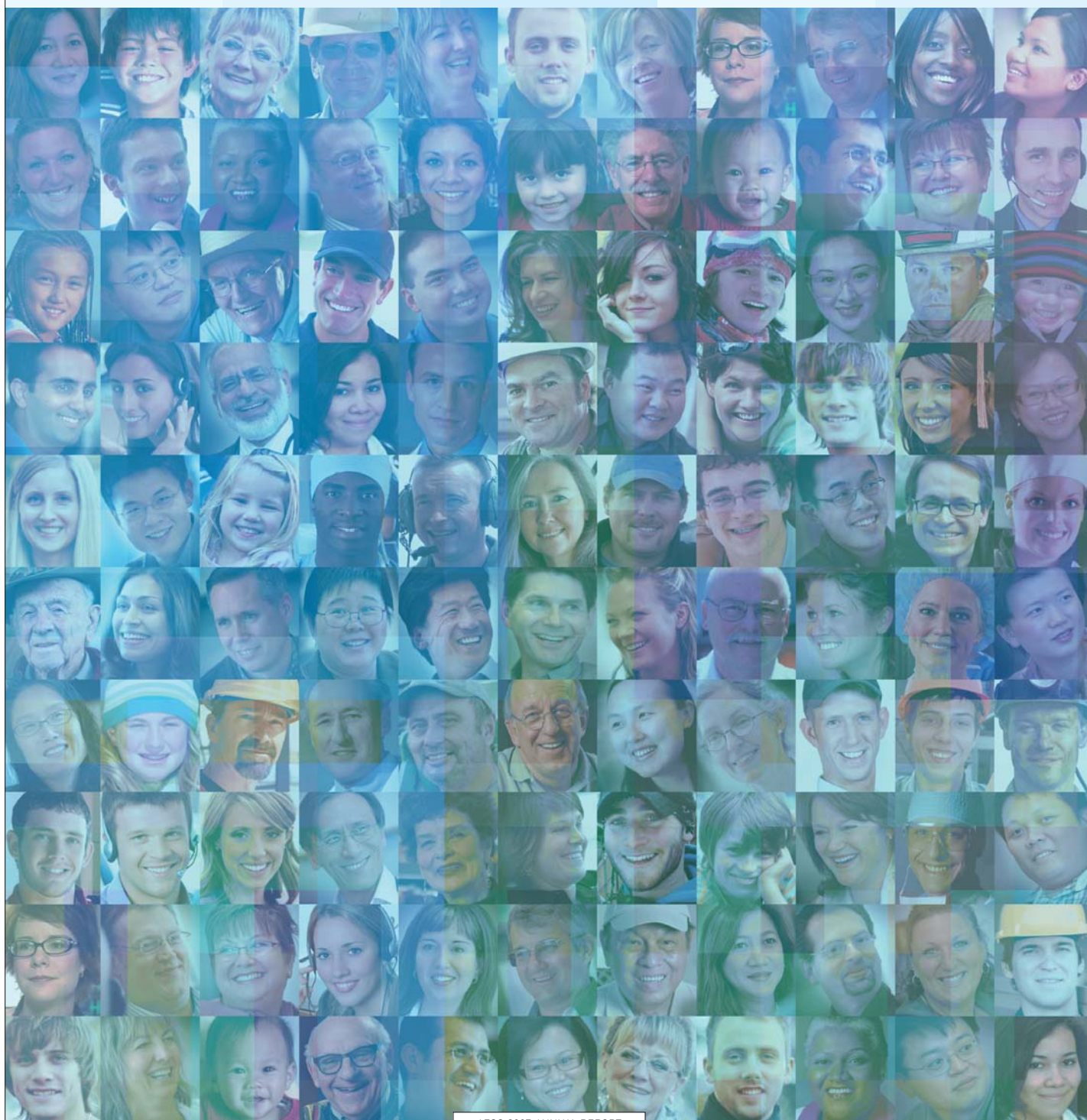
Auditors' Report

60

Financial Statements

63

Notes to  
Financial Statements



# MD&A

## 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, 2007 and 2006 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.*

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:

<i>(Millions) Years ended December 31</i>	<b>2007</b>	2006	Variance	% Variance
Transmission revenue	<b>\$ 905.1</b>	\$ 946.3	\$ (41.2)	(4)
Energy market charge	<b>13.7</b>	12.7	1.0	8
Load settlement	<b>5.1</b>	4.8	0.3	6
Interest and other income	<b>5.3</b>	1.3	4.0	308
Wire costs	<b>\$ 441.2</b>	\$ 444.9	\$ (3.7)	(1)
Ancillary services	<b>235.8</b>	235.2	0.6	0
Line losses	<b>183.8</b>	231.9	(48.1)	(21)
General and administrative	<b>52.2</b>	39.9	12.3	31
Amortization	<b>9.2</b>	9.2	–	–
Other industry costs	<b>4.8</b>	3.6	1.2	33
Interest expense	<b>2.2</b>	0.4	1.8	450



## 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 the following:

### Transmission

#### Revenue Summary

(Millions) Years ended December 31	2007	2006	Variance	% Variance
Transmission revenue	\$ 905.1	\$ 946.3	\$ (41.2)	(4)
Interest and other revenue	4.9	0.8	4.1	513
Total transmission revenue	\$ 910.0	\$ 947.1	\$ (37.1)	(4)

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 Energy and Utilities Board (EUB) prior to January 1, 2008 and thereafter the Alberta Utilities Commission (AUC). 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:

- ▶ The 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, Rate 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. Rate 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 2007 of \$4.9 million primarily relates to the interest earned on transmission customer contributions and transmission deferral funds held awaiting the annual deferral account reconciliation for years prior to 2007.

### Deferral Summary

(Millions) Years ended December 31	2007	2006
Collections	\$ 956.4	\$ 940.1
Costs	910.0	947.1
Transmission deferred revenue (revenue)	46.4	(7.0)
Deferral account payable, beginning of year	4.3	11.3
Deferral account payable, end of year	\$ 50.7	\$ 4.3

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 payable to transmission customers at December 31, 2007 increased to a \$50.7 million payable from a \$4.3 million payable at the end of 2006 as a result of 2007 transmission collections being \$46.4 million more than transmission costs.

The transmission deferral balance of \$50.7 million at December 31, 2007 is comprised of three components:

- ▶ The net revenue and cost adjustments of \$36.7 million payable to transmission customers relates to production years prior to 2007, which have accumulated since the AESO filed the 2003 deferral account reconciliation in the latter part of 2004.
- ▶ The variance in revenues collected and costs incurred in 2007 for the current year production have contributed to a transmission deferral account balance of \$15.1 million payable. The 2008 first quarter Rate Rider C and E rates are set to bring the deferral account balance to zero for the 2007 related production amounts.
- ▶ The transmission customer receivable of \$1.1 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	2007	2006	Variance	% Variance
Energy market revenue	\$ 13.7	\$ 12.7	\$ 1.0	8
Interest and other revenue	0.3	0.5	(0.2)	(40)
Total energy market revenue	\$ 14.0	\$ 13.2	\$ 0.8	6

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 is recognized by the AESO over the useful life of the assets. These assets are fully depreciated 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 the fourth consecutive year, the energy market trading charge is 11.1 cents per megawatt hour traded.

#### *Deferral Summary*

<i>(Millions) Years ended December 31</i>	<b>2007</b>	2006
Collections	<b>\$ 13.7</b>	\$ 13.9
Costs	<b>14.0</b>	13.3
Energy market (revenue) deferred revenue	<b>(0.3)</b>	0.6
Deferral account payable, beginning of year	<b>6.6</b>	6.0
Deferral account payable, end of year	<b>\$ 6.3</b>	\$ 6.6

The energy market deferral amount at December 31, 2007 is \$6.3 million payable compared to \$6.6 million payable at the end of 2006. The decrease of \$0.3 million during 2007 is a result of the amortization of system controller capital assets of \$0.3 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 2007, the MSA's portion of the total energy market trading charge of 13.6 cents per megawatt hour is 2.5 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 1.8 cents per megawatt hour in 2006.

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, 2007 and 2006, the difference between MSA collections and payments is less than \$0.02 million.

#### **Load Settlement**

##### *Revenue Summary*

<i>(Millions) Years ended December 31</i>	<b>2007</b>	2006	Variance	% Variance
Load settlement recovery	<b>\$ 5.1</b>	\$ 4.8	\$ 0.3	6
Interest and other revenue	<b>0.0</b>	0.0	–	–
Total load settlement revenue	<b>\$ 5.1</b>	\$ 4.8	\$ 0.3	6

The expenses that are incurred by the AESO to provide services related to 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*

<i>(Millions) Years ended December 31</i>	<b>2007</b>	2006
Collections	<b>\$ 5.4</b>	\$ 5.8
Costs	<b>5.2</b>	4.8
Load settlement deferred revenue	<b>0.2</b>	1.0
Deferral account payable (receivable), beginning of year	<b>0.8</b>	(0.2)
Deferral account payable, end of year	<b>\$ 1.0</b>	\$ 0.8

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.

<i>(Millions) Years ended December 31</i>	<b>2007</b>	2006	Variance	% Variance
Wire costs	<b>\$ 441.2</b>	\$ 444.9	\$ (3.7)	(1)
Ancillary services costs	<b>\$ 235.8</b>	\$ 235.2	\$ 0.6	0
Line losses	<b>\$ 183.8</b>	\$ 231.9	\$ (48.1)	(21)
Other industry costs	<b>\$ 4.8</b>	\$ 3.6	\$ 1.2	33

#### *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 decreased \$3.7 million or less than a one per cent compared to 2006 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 remains largely unchanged between 2007 and 2006. Costs increased to \$235.8 million in 2007 compared to \$235.2 million in 2006, an increase of \$0.6 million or less than one per cent. This increase is mainly due to the reduction in costs associated with operating reserves being more than offset by an increase in costs for TMR services as described on the following page.



**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 providers energy and/or capacity as reserves. The majority of operating reserve offer prices are indexed to the pool price.

Operating reserves costs decreased to \$180.7 million in 2007 compared to \$183.0 million in 2006, a decrease of \$2.3 million or one per cent. With comparable volumes in 2007 and 2006, the slight decrease is attributable to offer price strategies of the providers of operating reserves. A 17 per cent decrease in the average hourly pool price in 2007 (\$67 per megawatt hour compared to \$81 per megawatt hour in 2006) is offset by lower discounts, and in some cases premiums, offered by providers resulting in no significant change in the overall cost of operating reserves.

**Transmission Must-Run** is generation required to be on-line 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 increased to \$45.6 million in 2007 compared to \$41.3 million in 2006, an increase of \$4.3 million or 10 per cent. As previously mentioned, market heat rates and gas prices are the most significant factors contributing to changes in TMR costs. In 2007, the average market heat rate and the average gas price decreased 18 per cent and one per cent respectively (11.45 in 2007 from 13.99 in 2006 and \$6.10 per gigajoule in 2007 from \$6.17 in 2006) which resulted in an increase 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 are affected by short- and long-term outages of equipment due to maintenance and unexpected failures, and dispatch decisions on the AIES. The value of line losses is calculated at the hourly pool price.

The cost of line losses in 2007 is \$183.8 million compared to \$231.9 million in 2006, a decrease of \$48.1 million or 21 per cent. The volumes of line losses remain relatively consistent between 2007 and 2006 at approximately 2.87 and 2.84 terawatt hours annually.

The average hourly pool price, at which losses are valued, decreased by 17 per cent from 2006 causing line loss costs to decrease by 21 per cent. The average hourly pool price in 2007 is \$67 per megawatt hour compared to \$81 per megawatt hour in 2006.

### *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.

Other industry costs increased in 2007 by \$1.2 million or 33 per cent from \$3.6 million in 2006 to \$4.8 million in 2007. This increase is a result of a fluctuation in annual AESO regulatory proceedings and the timing of regulatory cost approval in addition to increases in the WECC membership and the AESO's share of the AUC's overhead costs.

### **General and Administrative Costs**

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

<i>(Millions) Years ended December 31</i>	<b>2007</b>	2006	Variance	% Variance
Salaries and benefits	<b>\$ 32.3</b>	\$ 27.5	\$ 4.8	17
Professional fees and consulting	<b>9.7</b>	4.8	4.9	102
Office and administrative	<b>10.2</b>	7.7	2.5	32
Total administrative	<b>52.2</b>	40.0	12.2	31
Amortization	<b>9.2</b>	9.2	–	–
Interest	<b>2.2</b>	0.4	1.8	450
Total general and administrative costs	<b>\$ 63.6</b>	\$ 49.6	\$ 14.0	28

### *Salaries and Benefits*

The increase is due to a full year of salary and benefits for staff hired in 2006, additional staff hired during 2007 and annual compensation adjustments for staff.

### *Professional Fees and Consulting*

The increase in professional fees and consulting in 2007 was required to supplement staff during peak work requirements which includes addressing new business initiatives and providing technical expertise. During 2007, the first stage of the Energy Management System (EMS) replacement project for project scoping and vendor selection occurred which utilized consulting services for project management and technical expertise. The other significant changes in 2007 addressed the AESO's response to business initiatives such as business continuity planning, operating protocols and enhanced public education and outreach arising from new industry responsibilities placed on the AESO.

### *Office and Administrative*

The notable increases relate to a full year of operating costs for the system coordination facility which was commissioned in December 2006 and the costs related to telecommunication links required between the new facility, the AESO's downtown offices and the secondary data centre.

### *Amortization*

Amortization of capital assets in 2007 includes the full year of amortization for the 2006 additions, new additions in 2007 offset by a reduction in amortization for assets that became fully amortized. Capital expenditures in 2007 are \$8.2 million, of which \$0.7 million are work-in-progress assets that are not yet subject to amortization.

### Interest

Interest expense is incurred as a result of the bank debt held throughout the year. 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. In 2006 and 2007, the AESO held \$31.0 million of transmission settlement funds awaiting final deferral account reconciliation for refunds to transmission customers. These funds are used to offset otherwise required debt balances to fund capital purchases and working capital. In the absence of holding these funds, the interest expense would have been \$3.6 million in 2007 and \$1.7 million in 2006.

## 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.

(Millions) Years ended December 31	General and Administrative		Amortization		Interest		Total	
	2007	2006	2007	2006	2007	2006	2007	2006
Transmission	\$ 39.1	\$ 28.6	\$ 3.9	\$ 3.0	\$ 1.5	\$ (0.1)	\$ 44.5	\$ 31.5
Energy market	10.6	8.9	3.1	4.3	0.3	0.1	14.0	13.3
Load settlement	2.5	2.5	2.2	1.9	0.4	0.4	5.1	4.8
Total	\$ 52.2	\$ 40.0	\$ 9.2	\$ 9.2	\$ 2.2	\$ 0.4	\$ 63.6	\$ 49.6

### General and Administrative

The percentage allocation of general and administrative costs by function required adjustments in 2007 to reflect changing operational activities with an increased emphasis on the transmission function in 2007 compared to 2006.

### Amortization

The notable changes in 2007 are due to the amortization of the system coordination facility commissioned in December 2006 offset by a reduction in annual amortization for the system coordination computer systems which were fully amortized at December 31, 2006. The allocation of these two capital assets relate to the transmission and energy market functions.

### Interest

In the absence of monthly surplus transmission deferral balances that occurred in 2006 that offset required borrowings for the net book value of capital assets and with the overall increase in capital assets, the average debt requirements increased in 2007. The use of \$31.0 million of transmission settlement funds awaiting final deferral account reconciliation offset otherwise required debt balances in both 2006 and 2007. An imputed interest income amount of \$1.4 million for 2007 is payable to transmission customers. Imputed interest income and expense amounts were determined and allocated to the appropriate function.

In comparing interest costs in 2007 and 2006 on a function basis, the debt financing for the three functions changed as a result of the underlying operational requirements.

## 5. FINANCIAL POSITION AND LIQUIDITY

### Deferral Summary

(Millions) Year ended December 31	2007
Cash, beginning of year	\$ 127.7
Operating activities	(97.3)
Investing activities	(8.2)
Financing activities	39.5
Cash, end of year	\$ 61.7

The cash balance as at December 31, 2007 is \$61.7 million compared to \$127.7 million at December 31, 2006. The decrease is primarily the result of the following:

- ▶ **Operating activities** used cash of \$97.3 million in 2007. The decrease is mainly attributed to a change in non-cash working capital of \$106.5 million. The accounts receivable and accounts payable balances at December 31, 2007 and 2006 relate to both November and December production months. The November settlement for both years occurred on the first business day in January due to the number of business days in December.
  - Accounts receivable balance at December 31, 2007 is \$182.6 million compared to \$191.8 million at December 31, 2006, a decrease of \$9.2 million. The decrease is primarily the result of a reduction in the November transmission receivables by \$4.2 million and a reduction in trade receivables by \$5.0 million at December 31, 2007.
  - Accounts payable balance at December 31, 2007 is \$192.9 million compared to \$308.4 million at December 31, 2006, a decrease of \$115.5 million. At December 31, 2007, the AESO received \$22.7 million in advance payments for the January 2, 2008 settlement compared to \$119.1 million at December 31, 2006 for the January 2, 2007 settlement, a difference of \$96.4 million. In addition, the November 2007 transmission costs are \$24.5 million lower than November 2006.
- ▶ **Investing activities** used cash of \$8.2 million for capital asset additions.
- ▶ **Financing activities** provided cash of \$39.5 million in 2007. The primary financing activities are an increase in deferral account payable to customers of \$46.4 million offset by a decrease in bank debt of \$6.9 million.

As at December 31, 2007, the AESO had the following credit facilities available to fund general operating and capital activities:

(Millions) Year ended December 31, 2007	Total	Available	Used
Term revolving facility	\$ 70.0	\$ 34.3	\$ 35.7
Demand revolving facility	\$ 70.0	\$ 70.0	\$ –
Demand treasury risk management facility	\$ 9.0	\$ 9.0	\$ –

The term revolving facility includes a \$10 million letter of credit at December 31, 2007 which is issued as security for the AESO's operating reserve procurement.

## 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 2008, the AESO established a revenue requirement of \$587.0 million through the 2008 Budget Review Process for costs related to ancillary services, line losses, other industry and general and administrative costs. A revenue requirement of \$480.8 million for wires costs results from approvals by the AUC for transmission facility owner tariffs. The total transmission revenue requirement of \$1,067.8 million represents a \$189.7 million or 21 per cent increase compared to \$885.8 million in 2007. The increase is primarily due to a forecasted increase in ancillary services and line losses costs in 2008 as a result of a forecasted increase in pool prices.

In 2008, the AESO is anticipating to have AUC approval or interim approval for the distribution of transmission deferral account balances to customers.

For energy market activities, the annual costs are forecasted to increase to \$16.5 million in 2008 from the 2007 actual costs of \$14.0 million, a \$2.5 million or 18 per cent increase. This forecasted increase is primarily the result of an increase in staff and benefits with smaller increases in several other cost areas. With the combination of this forecasted cost increase and the 2007 deferral balance, the AESO's portion of the 2008 energy market trading charge will remain unchanged from 2007 at 11.1 cents per megawatt hour. In 2008, the total energy market trading charge will be 14.1 cents per megawatt hour, a change from the 2007 charge of 13.6 cents per megawatt hour due to an increase in the MSA's component of the trading charge.

The AESO transitioned responsibility for the load settlement rules to the AUC on January 1, 2008; however, the AESO retained the responsibility to monitor compliance to these rules. With the newly legislated compliance and enforcement model in place for 2008, the AESO will be preparing to monitor compliance to reliability standards, AESO direct contracts, transmission project costing and standards. This is in addition to the AESO's current role of monitoring load settlement and ISO Rules governing the market. In taking on this broader role, the AESO will centralize compliance operations and establish new administrative rules, procedures and policies reflecting the changes in legislation.

In response to the increasingly complex operational requirements, security for the operations of the AES and the age of the existing system, a replacement of the EMS began in 2007 with staged commissioning to begin in April 2009 and completion targeted for early 2010. This replacement is a significant enhancement to the hardware and software of the business system used by 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. As the system operator, and its role and responsibilities as the sole buyer of ancillary services, the AESO implemented various business practice changes as a result and commenced an internal review. Both market participants and the MSA were advised of the change in business practices. In May 2007, the MSA initiated a review into the activities in the ancillary services market. The AESO is cooperating with the MSA, and will continue to do so, until the review is completed.

New market rules with accompanying AESO system modifications were implemented in December 2007 in alignment with the Government of Alberta's Market Policy and the Electricity Policy Framework (2005) project. Entering into 2008, the AESO will begin monitoring and providing analysis to the industry on the impact of these rules and will continue to work towards meeting market objectives as set out in the AESO's Market Services Market Roadmap.



## 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 and the Audit Committee 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, which facilitate the AESO's risk management processes are as follows:

- ▶ The AESO is governed by an independent 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. 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 officers, employees and contractors of the AESO when faced with difficult situations where laws and regulations are not enough to assist the employee. Employees are required to indicate their compliance with the Code of Conduct on at least an annual basis.
- ▶ The AESO's management and supervisory personnel monitor the quality of internal control performance as a normal part of their activities. Monitoring is performed over a wide variety of functions at all levels across the organization and occurs through the use of both automated and manual processes.
- ▶ 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, the 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](http://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 Alberta Electric System Operator 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 company'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, 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.

M. Dale McMaster, P. Eng.  
*President & Chief Executive Officer*

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, 2007 and 2006 and the statements of operations and comprehensive income and cash flows for the years then ended. These financial statements are the responsibility of the company'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 company as at December 31, 2007 and 2006 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 31, 2008

# Balance Sheet



As at December 31 (in thousands of Canadian dollars)		2007	2006
<b>ASSETS</b>			
Current assets			
Cash	\$	61,672	\$ 127,651
Accounts receivable (note 4)		182,645	191,762
Prepaid expenses and deposits		2,686	2,489
MSA deferral account receivable		—	16
		<b>247,003</b>	321,918
Capital assets (note 6)		<b>42,994</b>	43,970
	\$	<b>289,997</b>	\$ 365,888
<b>LIABILITIES</b>			
Current liabilities			
Accounts payable and accrued liabilities (note 7)	\$	192,927	\$ 308,428
AESO deferral accounts payable (note 8)		58,006	11,651
MSA deferral account payable		5	—
Security deposits (note 13)		1,541	1,689
Deferred government grants (note 5)		267	—
Bank debt (note 9)		35,700	42,600
		<b>288,446</b>	364,368
Deferred rent		1,551	1,520
<b>EQUITY (note 1)</b>		<b>—</b>	—
	\$	<b>289,997</b>	\$ 365,888

Asset retirement commitment (note 10)

Contingencies and commitments (note 11)

On behalf of the AESO Board:

Harry Hobbs  
Chairman

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

# Statement of Operations and Comprehensive Income



<i>For the Year Ended December 31 (in thousands of Canadian dollars)</i>		2007	2006
<b>REVENUE</b>			
Transmission tariff	<b>\$</b>	<b>905,079</b>	\$ 946,303
Energy market charge		<b>13,654</b>	12,712
Load settlement charge		<b>5,136</b>	4,820
Interest and other		<b>5,327</b>	1,413
		<b>929,196</b>	965,248
<b>OPERATING COSTS AND EXPENSES</b>			
Wire costs		<b>441,185</b>	444,931
Ancillary services costs		<b>235,848</b>	235,175
Line losses		<b>183,787</b>	231,927
General and administrative		<b>52,187</b>	39,947
Amortization (note 6)		<b>9,190</b>	9,234
Other industry costs		<b>4,809</b>	3,585
Interest expense (note 9)		<b>2,190</b>	449
		<b>929,196</b>	965,248
<b>NET INCOME AND COMPREHENSIVE INCOME</b>	<b>\$</b>	<b>—</b>	\$ —



# Statement of Cash Flows



<i>For the Year Ended December 31 (in thousands of Canadian dollars)</i>		2007	2006
<b>OPERATING ACTIVITIES</b>			
Net income	\$	—	\$ —
Amortization		<b>9,190</b>	9,234
Changes in non-cash working capital*		<b>(106,462)</b>	105,008
Net cash provided by operating activities		<b>(97,272)</b>	114,242
<b>INVESTING ACTIVITIES</b>			
Capital asset additions		<b>(8,214)</b>	(24,419)
Net cash used in investing activities		<b>(8,214)</b>	(24,419)
<b>FINANCING ACTIVITIES</b>			
(Decrease) increase in bank debt		<b>(6,900)</b>	12,500
Increase in deferred rent		<b>31</b>	55
Increase (decrease) in AESO deferral accounts		<b>46,355</b>	(5,472)
Increase (decrease) in MSA deferral account		<b>21</b>	(193)
Net cash provided by financing activities		<b>39,507</b>	6,890
<b>INCREASE IN CASH</b>		<b>(65,979)</b>	96,713
<b>CASH, BEGINNING OF YEAR</b>		<b>127,651</b>	30,938
<b>CASH, END OF YEAR</b>	\$	<b>61,672</b>	\$ 127,651
Cash interest paid	\$	<b>2,155</b>	\$ 828

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

# Notes to the Financial Statements

December 31, 2007 and 2006 (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 regulating 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). 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.

**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 is recorded as deferred revenue and is incorporated into the estimated per megawatt hour (MWh) 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 years
System coordination facility	Over the land lease term ending in 2025
Energy trading system	8 years
System coordination computer systems	8 years
Computer hardware, furniture and office equipment	3 years
Leasehold improvements	Over the lease term ending in 2014
Facility infrastructure	10 years

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: (1) the transmission tariff; (2) the energy market charge; and (3) 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 Canadian Institute of Chartered Accountants (CICA) has published five new accounting sections to the CICA Handbook: Section 1530, Section 3855, Section 3861, Section 3865 and Section 1506.

- ▶ Section 1530: Comprehensive Income addresses fair value accounting and reporting and disclosure standards for comprehensive income.
- ▶ Section 3855: Financial Instruments – Recognition and Measurement addresses when financial instruments should be measured and how measurement should occur.
- ▶ Section 3861: Financial Instruments – Disclosure and Presentation provides standards for how financial instruments should be classified on the financial statements as well as related disclosure requirements.
- ▶ Section 3865: Hedging specifies the criteria under which hedge accounting may be applied, how hedge accounting should be performed under permitted hedging strategies and the required disclosures. These standards require that entities categorize financial instruments and measure certain financial instruments at fair value.
- ▶ Section 1506: Accounting Changes addresses the required disclosures when an entity has not applied a new source of GAAP that has been issued but is not yet effective.

All of these new standards were adopted by the AESO on a prospective basis in accordance with the recommendations of the CICA for the period commencing January 1, 2007. In accordance with the transitional provisions, prior periods have not been restated as a result of adopting these standards. The AESO has evaluated the impact of these new standards and the adoption of these recommendations has not had an impact on the financial statements. Comprehensive Income is the same as Net Income during the period.

The AESO has evaluated the five classifications of financial instruments, namely held for trading, available for sale, held to maturity, loans and receivables and other financial liabilities, and designated its financial instruments as follows:

- ▶ Cash is classified as assets held for trading at fair value.
- ▶ Accounts receivable and deferral accounts receivable are classified as loans and receivables and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.
- ▶ Accounts payable and accrued liabilities, deferral accounts payable, security deposits and bank debt are classified as other financial liabilities and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.

It is management's opinion that the AESO is not exposed to significant interest rate, currency or credit risks arising from these financial instruments.

**Upcoming Pronouncements** – CICA Handbook Sections 3862: Financial Instruments Disclosures, Section 3863: Financial Instruments Presentation, and Section 1535: Capital Disclosures are required to be adopted for fiscal years beginning on or after October 1, 2007. Section 3031: Inventories is required to be adopted for fiscal years beginning on or after January 1, 2008. The AESO will adopt these standards on January 1, 2008 and it is expected the only effect will be incremental disclosures regarding the significance of financial instruments for the entity's financial position and performance and the nature, extent and management of risks arising from financial instruments to which the entity is exposed.



### 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.

<i>As of December 31</i>	<b>2007</b>	2006
<b>Regulatory asset</b>		
Regulatory hearing costs	\$ 71	\$ 91
<b>Regulatory liabilities</b>		
Transmission deferral	\$ 50,657	\$ 4,278

During 2007, \$0.1 million was incurred in legal and consulting fees related to the AESO's 2007 General Tariff Application regulatory proceeding. The AESO expects to receive approval for recovery of these costs with the completion of the regulatory process. The Regulator will issue a Utility Cost Order that approves allowable and recoverable hearing costs. 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. The regulatory asset is included in accounts receivable on the balance sheet at December 31, 2007.

At December 31, 2007, the transmission deferral liability was \$50.7 million based upon an accumulation of variances between transmission revenue collections and costs incurred from 2007 and prior years. The AESO applies to the Regulator for the approval and settlement of prior years' 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 liability is included in the AESO's deferral accounts payable on the balance sheet at December 31, 2007.

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

	<b>2007</b>	2006
Transmission settlement	\$ 176,956	\$ 181,154
Energy market settlement	2,881	2,734
Trade	2,808	7,874
	<b>\$ 182,645</b>	<b>\$ 191,762</b>

## 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 related 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 has complied with the terms of the grant agreements to date 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, \$0.3 million in funding has been received with the remaining funding commitment of \$0.4 million recorded in accounts receivable.

In 2007, the financial statements recognize a reduction to general and administrative expenses of \$0.4 million and a deferred charge balance of \$0.3 million related to grants accrued in advance of project expenses. When the project expenses are incurred in 2008, the deferred charge balance will be netted against general and administrative expenses.

## 6. CAPITAL ASSETS

2007			
	Cost	Accumulated Amortization	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
	<b>\$ 71,086</b>	<b>\$ 28,092</b>	<b>\$ 42,994</b>

2006			
	Cost	Accumulated Amortization	Net Book Value
Software development	\$ 20,464	\$ 7,036	\$ 13,428
System coordination facility	18,759	84	18,675
Energy trading system	11,410	9,812	1,598
System coordination computer systems	11,406	11,406	–
Computer hardware, furniture and office equipment	6,586	3,360	3,226
Leasehold improvements	2,798	935	1,863
Facility infrastructure	2,501	21	2,480
Work in progress	2,700	–	2,700
	<b>\$ 76,624</b>	<b>\$ 32,654</b>	<b>\$ 43,970</b>

Work in progress in 2007 and 2006 relate to capital acquisitions associated with various hardware and software development projects that were not commissioned or operational by the end of the year.

For the 12 months ended December 31, 2007, \$1.4 million of payroll and payroll-related costs associated with staff directly involved in software and hardware development have been capitalized (2006 – \$1.1 million). No interest costs were capitalized in 2007 (2006 – \$0.4 million).

## 7. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2007	2006
Transmission settlement	\$ 150,465	\$ 196,730
Energy market settlement	23,498	89,230
Trade	14,033	16,186
Accrued liabilities	4,931	6,282
	<b>\$ 192,927</b>	<b>\$ 308,428</b>

The accounts payable, trade balance includes flow-through customer contribution amounts of \$2.8 million in 2007 and \$11.1 million in 2006.

## 8. AESO DEFERRAL ACCOUNTS PAYABLE

	Transmission	Energy Market	Load Settlement	Total
Opening balance, January 1, 2006	\$ 11,322	\$ 6,042	\$ (241)	\$ 17,123
2006 Operations	(7,044)	568	1,004	(5,472)
Closing balance, December 31, 2006	4,278	6,610	763	11,651
2007 Operations	46,379	(298)	274	46,355
Closing balance, December 31, 2007	<b>\$ 50,657</b>	<b>\$ 6,312</b>	<b>\$ 1,037</b>	<b>\$ 58,006</b>

## 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 2007 and 2006.

At December 31, 2007, \$35.7 million was drawn on the demand revolving loan facility and a \$10.0 million letter of credit was issued 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 \$2.2 million (2006 – \$0.8 million) at an average interest rate of 4.5 per cent.

## 10. 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.

## 11. 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)
2008	2.3
2009	1.8
2010	1.8
2011	1.9
2012	2.0
Thereafter	4.8

- (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 15 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 which 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 which the AESO may be required to pay would have a materially adverse effect on the corporation 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 2007, \$3.0 million was paid to the MSA (2006 – \$2.3 million).

## 12. 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 \$2.2 million in 2007 (2006 – \$1.8 million).

## 13. 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 AESO's 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 regulation.

## 14. FINANCIAL INSTRUMENTS AND CREDIT RISK

The AESO's financial instruments consist of cash, accounts receivable, AESO deferral accounts receivable/payable, MSA deferral accounts receivable/payable, accounts payable and accrued liabilities, security deposits and bank debt. Due to their short-term nature, the fair market value of the financial instruments approximates the carrying value.

The credit risk associated with accounts receivable is generally considered to be low since substantially all counterparties are well established utility or power companies. There is no concentration of balances with debtors.



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