Alberta Electric System Operator

2006 Annual Report

Reliable 24.7.365

Alberta Electric System Operator

The AESO facilitates a fair, efficient and openly competitive market for electricity and provides for the safe, reliable and economic operation of the Alberta Interconnected Electric System. To keep the lights on we manage the system that powers everyday living in Alberta. Our job is to ensure all Albertans receive safe, economic and reliable power – today and in the future.

TABLE OF CONTENTS

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Reliable
24 hours a day
7 days a week
365 days a year

We are 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.

We manage

the coordinated operation of the power grid, ensuring that the supply of power is in constant balance with electricity demand across the province.

We plan

the provincial transmission system, including interties with neighbouring jurisdictions. We strive to ensure this important infrastructure is reinforced and expanded in order to keep pace with the growing demand for power.

We operate

Alberta's competitive wholesale electricity market, with about 200 participants and over $7 billion in annual energy transactions.

We are a not-for-profit organization. We don't own or operate any power facilities and we don't have a financial investment in the industry. We are driven in all our business activities to plan, develop and operate the power system and the competitive market for electricity in the public interest.

Message from the Chair

Harry Hobbs
Board Chair

A MESSAGE TO ALBERTANS:

As I reflect on my first year as Chair of the Alberta Electric System Operator I see an electric industry that has faced significant change and has responded extremely well to those challenges. There is, in my opinion, good reason to be optimistic that the forthcoming year will see continuing stabilization of the frameworks in which we all operate. While certain modifications are inevitable as we adapt to a new *Transmission Regulation* and regulatory framework, and as we continue to implement the market design, there is also a great opportunity for parties to seek negotiated solutions to remaining common issues.

Alberta is vibrant. Our province is attracting new investment, industry and people at an unprecedented pace. At the same time, this growth has placed increased demands on our electric system infrastructure. To date, that system has responded well. However, to successfully manage forecasted provincial growth requires effective and timely responses from all sectors of Alberta. A key goal for the AESO is to see sufficient transmission capacity constructed as soon as possible to provide reliable system operation and facilitate the competitive electricity market, to provide generators with signals supporting their investment in new power supply and to underpin industrial and residential load objectives.

ORGANIZATIONAL OBJECTIVES

The AESO's mandate and primary objective is embodied in our vision which states: The AESO will be 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.

To meet that vision, the Board of the AESO and its executive management team, following stakeholder consultation, established four key objectives to be met by the organization. These are:

- To build appropriate transmission capacity to meet the forecasted needs of Alberta, facilitate competitive markets and meet the challenges of provincial economic aspirations, extreme weather, expanding markets and disaster avoidance.
- Stabilize the market and regulatory frameworks to enhance confidence of investors and market participants.
- Define, design and implement a comprehensive risk management approach that identifies, monitors and mitigates all risks to the extent feasible.
- Attract and retain appropriately skilled people at the AESO to ensure we have the resource capacity and expertise to meet our objectives.

In 2006, the Board believes that the team of management and employees did an outstanding job of furthering the organization's objectives to the benefit of all industry sectors and Albertans as a whole.

Each year a business plan is developed by management and reviewed by the Board to set annual objectives and targets which will achieve substantial progress in attaining those goals. In 2006, the Board believes that the team of management and employees did an outstanding job of furthering the organization's objectives to the benefit of all industry sectors and Albertans as a whole. The organization achieved success while exhibiting the key qualities important to us as Board members: taking on a leadership role when required, acting with integrity in an open and transparent manner, providing quality and timely results, showing innovation in arriving at solutions and conducting its activities in a cooperative and collaborative manner with our stakeholders. Our commitment to continual improvement in all areas of our business will present a high threshold for our organization to meet in 2007.

As we look to the upcoming year and beyond, it is critical to all Albertans that we meet the challenge to construct sufficient transmission capacity to provide necessary reliability for provincial needs. Our population has doubled from 1.5 million people in 1985 to 3.2 million in 2006 without new transmission capability. The strength of our economy has also created additional demand, setting new records for power use in 2006. Alberta's transmission system delivers power from generators to users across the province in an instant; however, we are continuing to push higher volumes through these lines. Significant upgrades are necessary in a timely manner to match system capacity to this growing need. In order to maintain the same strong reliable infrastructure Albertans have come to expect, the system must be reinforced and expanded.

FUTURE CHALLENGES – 2007 AND BEYOND

It is essential that organizations such as the AESO take a long-term perspective.

In March 2007, the AESO executive team and the Board conducted its annual review of the five-year strategic plan that was developed in 2006. This plan, which was approved by the Board, looks beyond the near term and establishes a direction for the organization that will guide its actions into the future.

The plan is fully aligned with the organizational mission of facilitating a fair, efficient and openly competitive market for electricity while providing for the safe, reliable and economic operation and development of the Alberta grid. While the plan itself remains fundamentally sound, there is a recognition of the increasing role that technological and environmental initiatives will play in affecting both market dynamics and investment decisions. There is also a need for the AESO to extend its outreach programs to meet its mandate to disseminate information relating to current and future electricity needs throughout the province.

We can commit to our stakeholder community that our management and employees welcome the opportunity to be a public interest leader in the power industry.

The AESO will look for opportunities to play a key role in the assessment of new approaches to streamline approval processes while maintaining a fulsome regulatory review. We also intend to focus attention on inherent risks and their mitigation for the Alberta Interconnected Electric System, to continue our on-going review and modification of internal controls and to work with the wind industry and other generators to find new opportunities to enhance the climate for their electricity supply investments.

We look forward to building on the success of an open, interactive budget review process that involves Board member review with interested stakeholders. We hope that this example can be a catalyst to longer-term arrangements.

The next year will represent a significant challenge to achieving our objectives as an organization. However, we can commit to our stakeholder community that our management and employees welcome the opportunity to be a public interest leader in the power industry. We will embrace this role knowing that our commitment to open, transparent consultative processes and a solution focus will serve us well in our collaborative efforts with stakeholders.

CONCLUSION

In conclusion, I would like to express, on behalf of the Board, our confidence in the leadership shown by the AESO executive team and the outstanding efforts of our employees. As Chair, I am well acquainted with the challenges facing this organization and the industry as a whole. The AESO team has delivered, and will continue to deliver, quality and timely results for Albertans in what is often a volatile environment.

I would also like to recognize the quality of support, feedback and advice from our stakeholders, including the Alberta Department of Energy. This is essential to effective collaboration and central to the organization's ability to deliver workable solutions that are fair and balanced, as well as to ensure timely responses to areas of concern. I would like to thank stakeholders for their commitment to working together in support of a safe and reliable power grid and transmission system and an openly competitive marketplace.

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I would also like to commend my fellow Board members who have responded above and beyond the call to manage the balance of maintaining an effective working relationship with the CEO and management team, while providing diligent oversight of the organization with penetrating and challenging questions and observations.

At this time, I would also like to recognize members of our Board that have retired in the past year. On behalf of the AESO, I want to thank John Feick, Bob McKenzie and Murray Nelson for their many contributions to the continued evolution and success of our organization. I also want to extend our collective appreciation to former Chair, Maury Parsons, for his commitment to the AESO and his outstanding leadership in creating and growing the AESO to fulfill its mandate to Alberta.

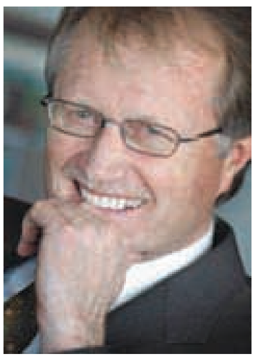
It is the continuing goal of the AESO to advance the organization's objectives to the benefit of Albertans.

Respectfully submitted,

Harry Hobbs
Chair, Board of Directors

April 2007

Message from the CEO



Dale McMaster
President and CEO

RELIABLE – IT'S OUR COMMITMENT TO ALBERTANS – 24.7.365

Over the past year, we have successfully executed our core businesses of operating the interconnected electric system; developing the transmission system; providing transmission system access to our customers; and, facilitating the operation and development of the competitive market for electricity in Alberta in an environment of growth that has challenged industry, government and the AESO.

Demand for electric energy in our province reached 69 million megawatt hours in 2006, a five per cent increase over 2005 and a 28 per cent increase since 2000. Alberta also set a new record for peak demand of 9,661 megawatts (MW) in November 2006. Current projections are that up to 3,800 MW of new generation may be required by 2016 to meet continued growth.

The stresses of this growth are affecting the electric system infrastructure which is a key underpinning to the economy of Alberta and the quality of life for all Albertans. We depend on highly reliable power service as interruptions in supply can have far-reaching consequences for everyone.

While the power grid is capable of meeting Alberta's current demand for electricity, we are operating at or near system operating limits more frequently and for longer duration. As a consequence, we've had to be increasingly diligent and innovative in our approach to managing the system. The impact on electric reliability of an unplanned or forced outage of a critical transmission system element or major generating station is increasing.

In Alberta, we rely on the competitive market for electricity to incent investment in new supply. To facilitate that investment it is essential that a reliable and unconstrained transmission system is in place to ensure that investments in new supply can be reliably taken to market. It is equally important that the market signals that guide investment in new supply are reliable and trusted.

The transmission system must be reinforced to ensure overall system reliability and to facilitate investment in new supply. Strengthening of the backbone of the system with a new 500-kilovolt (kV) transmission line between Edmonton and Calgary was a primary focus in 2006 and will remain so for 2007. Completing this expansion is critical for Alberta's transmission system to continue delivering a stable, reliable supply of electricity for the province. In December 2006, following a second hearing to ensure the concerns of landowners were heard and taken into account, the Alberta Energy and Utilities Board (EUB) confirmed their earlier decision that the transmission line was needed and should be built in the "west corridor". There are impacts when developing major infrastructure. We are sensitive to those impacts and strive for balanced decisions through consultation. Although our goal to commission the line remains late 2009, meeting this timeline presents a major challenge.

Leadership. Integrity. Quality. Innovation. Collaboration. These are the values that guide our work to meet the power needs of Albertans every minute of every day.

Other milestones achieved in 2006 by our operations, IT and transmission teams included the commissioning of our new system coordination centre – the nerve centre of Alberta's power grid; the completion and submission of the 10-Year Transmission System Plan; and, the filing of the Need Application for the proposed Montana Alberta Tie Ltd. (MATL) merchant transmission line from Lethbridge to Great Falls, Montana. We also received EUB approval of the need for a major transmission reinforcement to the northwest part of the province. This approval was achieved without a regulatory hearing thanks to an extensive consultative process and the proactive participation of stakeholders in that process.

As might be expected given the level of economic activity and the rate of load growth, we are experiencing an unprecedented number of requests for interconnection to the system. Currently, our customer interconnections team is working on over 120 requests for system access. That being said, we continue to see improvements in project timelines while delivering a high standard of engineering to ensure that customer needs are met. This is in part due to the collaborative efforts of the EUB and the AESO to establish an approval process for customer interconnections, and small system projects under $10 million. This new process ensures appropriate regulatory oversight of projects while expediting approvals.

The operation and development of the competitive market for electricity is a significant part of our mandate. Over the past year, we have collaborated with stakeholders on rule changes to increase confidence in the fidelity of the market price signal. This work has focused on merit order stabilizers of "must offer/must comply" and on removing price distortions such as those that result from transmission must-run generation. In March 2007 the AESO approved rules that do not require any changes to legislation or government regulations. These changes, which will be implemented in 2007, will significantly increase the visibility of available supply to the marketplace and enhance the confidence in the pool price.

The transmission tariff is a major component of the overall electricity market. In 2006, we carried out extensive consultation with respect to our 2007 general tariff application. The application proposes updates to a number of aspects of the rates and terms and conditions for system access service, primarily in response to directives from the EUB decision and stakeholder input. Our application was filed with the EUB in November 2006. The EUB hearing for the tariff is scheduled for May 2007.

One of the great success stories of the restructured electric industry in Alberta has been the development of wind generation. At present we have over 300 MW of wind connected to the system and over 3,000 MW of wind generation has applied for interconnection. The AESO is committed to integrating as much wind power into the Alberta electric system as is feasible without compromising system reliability or the fair, efficient and openly competitive operation of the market.

Our mandate to serve in the public interest results in the best solutions that balance the impacts with the benefits delivered.

As part of this commitment, we are collaborating with the Canadian Wind Energy Association (CanWEA) on a number of initiatives, including a wind forecasting project, to gain a greater understanding of the impact of a large amount of wind generation on the electric system and to identify the means to mitigate its impact. It is our objective to replace the 900 MW threshold with a framework of tools, market rules, interconnection standards as well as operating policies and procedures that will allow market forces to govern investment decisions for wind generation facilities.

Interties with neighbouring jurisdictions are an important contributor to the reliable operation of the interconnected electric system and to the facilitation of competitive markets. The capacity of our existing interties is constrained due to the heavy demand on the transmission system and the lack of system reinforcements over the last 20 years. As directed by the provincial government's *Transmission Regulation*, the interties will be restored to their original design capability by strengthening the internal Alberta transmission system. In the interim, in collaboration with stakeholders, we are developing, innovative ways to achieve incremental improvements to the capability of the interties without compromising system reliability. Over the last year, significant incremental increases were achieved in the export capability of the Alberta-B.C. 500-kV intertie.

As we look to 2007 we face many challenges. On the operational front we face the increasing challenge of operating a stretched transmission system and, the introduction and implementation of mandatory reliability standards across Canada and the United States. We will also initiate a multi-year project to upgrade our existing SCADA and Energy Management System to ensure ongoing reliability and compliance with North American Electric Reliability Corporation (NERC) cyber security standards.

From the perspective of system planning we will complete and file a Need Application with the EUB to reinforce the southeastern part of the province to ensure system reliability, facilitate the potential interconnection of wind generation and restore the capability of the Alberta-Saskatchewan intertie. We will also continue planning for the following:

- reinforcements to the northeastern part of the province to meet load growth in the Fort McMurray area;
- expansion to the system north of Fort McMurray to provide service to a number of new oilsands developments;
- reinforcement of the Edmonton to Calgary backbone with a second 500-kV transmission line; and,
- system expansion to serve the needs of proposed bitumen upgrading and refining facilities in the Fort Saskatchewan area.

In addition to addressing the requests for system access service, our engineering team will continue to focus on the implementation of the southwest system reinforcement, the Calgary to Edmonton 500-kV transmission line, the City of Edmonton reinforcement and the northwest system reinforcement.

This will be another challenging year for stakeholders and the AESO's Market and Regulatory Framework group. Our work plans call for the review of our procurement practices in the ancillary services market; the review of rules for agency agreements between market participants; the development and implementation of rules regarding the out-of-market commitment of generating units for reliability purposes; advancement of dispatchable interties; and, a comprehensive review of our authoritative documents including the AESO tariff, market rules, operating policies and procedures as well as business practices to ensure consistency in application and compliance.

In addition, we are actively involved in a consultative process led by the government to review Section 6 of the *Electric Utilities Act*. Section 6 states that power market participants must behave in a manner that supports the fair, efficient and openly competitive operation of the market. Following the completion of the Section 6 discussion, in consultation with stakeholders, we will initiate the development of a Market Roadmap. Similar to a longer-term transmission development plan, the roadmap is intended to guide the market development activities over the next five years. The goal is to create greater confidence in the market and a level of stability and certainty that encourages investment and enhances the long-term viability of the market.

As 2007 began we made some adjustments to the organizational structure and responsibilities within our existing team. These changes better align our organization with our strategy and business plans. We will continue to refine our organization's training and development strategy to make sure we are attracting and retaining top quality talent.

Over the past year, the AESO team has dedicated considerable effort to improving our consultation process and working relationships with stakeholders. We continue engaging and consulting with senior level representatives from across industry and government in a process of collaboration around policy development and industry project coordination. One of our key successes is our stakeholder engagement process in the preparation of our annual budget, where significant improvements in transparency and credibility have been achieved. We will continue to refine this process and other processes to capture additional regulatory efficiencies and enhance stakeholder confidence.

The environment has emerged on numerous fronts and has captured worldwide attention. Because of its significance, we expect further policy developments on matters associated with the environment that will affect our industry, our business operations and the services we provide. We will be diligent in monitoring how policy initiatives evolve and work with stakeholders to prudently act on this issue and others that come to the forefront of our industry and our business.

At the time of writing this report, there have been two significant developments affecting the regulatory framework of our industry. The Ministry of Energy announced legislation this spring for the separation of the existing EUB into two distinct entities. The Energy Resources Conservation Board will focus on the development of energy resources, while the Alberta Utilities Commission will oversee all regulatory aspects of the power industry. We will be working with the Ministry of Energy on how we can gain maximum efficiencies from this change while maintaining the required regulatory oversight as in the past.

The second regulatory development is the enactment of a new *Transmission Regulation*. The new regulation provides additional clarity regarding some of our accountabilities and we'll be working closely with stakeholders and the Alberta Department of Energy to ensure that these important enhancements are implemented in a consultative and collaborative manner.

In closing, I would like to extend my sincere thanks to all stakeholders, for their support, cooperation and collaboration. I strongly believe that a consultative approach results in a greater common understanding and ultimately a better outcome to meet the reliability needs of Albertans and business needs of our market participants.

I'd also like to acknowledge the efforts of our employees over the past year as well as their commitment to our core values of leadership, integrity, quality, innovation and collaboration. I've described several examples of the work we've accomplished in 2006, which demonstrate how these values guide our work.

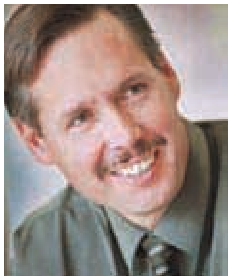
Finally, I would like to acknowledge our Board of Directors. Their varied, extensive experience and judgment is of great value to our executive team and to me. Without their support we could not have achieved the successes of 2006, or be as well positioned to achieve our goals for 2007. It is these combined efforts that are responsible for consistently and reliably delivering for Albertans – 24.7.365.

Dale McMaster
President and CEO

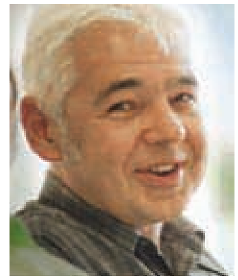
April 2007

AESO Year in Review

Reliable 24.7.365


Ken Gardner


Anita Lee


Ric Wilson


Kelly Fraser

Reliable Power

SYSTEM OPERATIONS

One of our key accomplishments in 2006 was the commissioning of a new system coordination centre – the nerve centre of Alberta's power grid. The Centre became fully operational in January 2007. Despite the current challenges of the construction industry in Alberta, the Centre was completed within the approved $21 million budget and on schedule. The Centre incorporates best practices from across industry and provides us with a state-of-the-art facility from which to direct system operations and address the security requirements of the Alberta Electric System Operator (AESO).

In 2007 we will initiate a multi-year project to upgrade our SCADA and Energy Management System; a critical IT system that provides the centralized operations of the Alberta Interconnected Electric System (AIES). This is necessary to ensure ongoing reliability of system operations and compliance with North American Electric Reliability Corporation (NERC) standards regarding cyber security.

As demands on Alberta's transmission system continue to grow, the need to reinforce the system becomes paramount. Expanding the capacity of the transmission system is absolutely necessary to ensure the increased levels of electricity can continue being reliably delivered. We are operating the power grid closer and closer to its physical limits while we continue to move ahead with planning and building critical system reinforcements to meet the needs of Albertans today and into the future.

Extensive operational planning studies were carried out over the year to establish safe operating limits for the power system. While there is a need to reinforce the transmission grid, generation also plays a key role, beyond the provision of power, in overall reliable system operations. Over the past year the AESO has worked with generation facility owners to ensure generators were able to meet the AESO's reactive power standards. We have also worked collaboratively with generator owners to enhance plant maintenance coordination to avoid inadvertent shortfalls of supply.

Photo on previous page:
Ralph Gruendel, a system controller at our system coordination centre.

Mandatory Reliability Standards

Throughout North America the electricity industry is moving to implement mandatory reliability standards as an important measure to ensure reliable operation of the power system. The AESO will play a significant role in this work in coordination with the NERC and the Western Electricity Coordinating Council (WECC).

The WECC is the organization responsible for coordinating and promoting electric system reliability across the 1.8 million square miles that span western Canada, the Western U.S. and Mexico. An important element of the Alberta framework was to establish Canadian representation on the WECC Board of Directors.

Our organization played a key leadership role in securing five seats for Canada, to be shared between B.C. and Alberta. The AESO holds one of those seats and will ensure the Alberta perspective is brought to all discussions regarding reliability standards and operation of the interconnected power system.

In 2007, we are undertaking an initiative to review all of the proposed WECC reliability standards to determine if they are appropriate for use in Alberta. This project will involve stakeholder consultation to ensure that all power facility owners, operators and users of the AIES understand and comply with Alberta-approved reliability standards when operating and maintaining their facilities. Our project will also expand our existing business relationships with NERC, WECC and the Independent System Operator/Regional Transmission Organization Council (IRC) to ensure streamlined processes are used for the work we do together.

During the last year we also worked with the Department of Energy and the Alberta Energy and Utilities Board (EUB) to establish a framework for Alberta to oversee the development, implementation and enforcement of mandatory reliability standards in the province. Alberta supports the establishment of industry-wide mandatory reliability standards but will retain the authority to approve and implement reliability standards in a manner that respects the requirements of our system and market structure.

TRANSMISSION SYSTEM DEVELOPMENT PLANNING AND PROJECTS

A priority for our transmission team in 2006 and this year is a major reinforcement of the system between Edmonton and Calgary.

This transmission system is the backbone of the provincial grid and has not been upgraded since the 1980s. Completing this expansion is critical for Alberta's transmission system to continue delivering a stable, reliable supply of electricity for the province as our economy and population grows. Over the past year, in order to ensure landowner concerns were taken into account at the needs stage of the regulatory process, the EUB convened another hearing to test the suitability of the "western corridor" as approved in the original EUB decision. This in fact was confirmed in a decision rendered by the EUB in December 2006.

AltaLink Management Ltd. (AltaLink), the transmission facility owner that will construct and own the transmission line, has submitted its application to the EUB for a permit to construct and license to operate the facilities. At the time of writing this report the EUB hearing into AltaLink's application was commencing.

Northwestern Alberta

A major accomplishment in 2006 for the AESO was regulatory approval of our need application for a $300-million transmission reinforcement in the northwest region of Alberta.

In August 2006, the EUB approved our application without the need for a hearing. We believe that our comprehensive, open and transparent industry stakeholder consultation on this important project was instrumental in no objections being filed in relation to the application; therefore, no hearing was required. This significantly expanded consultation process has set the bar for future projects. We are committed to continual improvement in our process by initiating consultation earlier and significantly broadening the base of stakeholders who will be consulted at the needs identification stage of projects.

We are working with ATCO Electric, the transmission facility owner in the region, as they develop detailed engineering and prepare an application for the permit to construct and license to operate. The new facilities are targeted for sequential commissioning from 2008 to 2011. A unique aspect of this particular application was that we also applied for, and had approved, the acquisition of a right-of-way at an estimated cost of $2.5 million for future transmission development in the region.

Rob Baker

Southwestern Alberta

The reinforcement to the southwestern transmission system has experienced some delays despite the EUB approval for the project in 2005. This reinforcement is needed to maintain regional reliability and to facilitate the potential interconnection of about 1,100 MW of wind generation on the system. The delays were the result of the need for AltaLink to complete additional environmental impact assessment work since a portion of the line crosses land that is under federal government jurisdiction. AltaLink has now completed this work and expects to file an application for a permit to construct and license to operate in the summer of 2007. The project is currently targeted to be in-service in late 2008.

Iris Sutton

City of Edmonton

Over the past year, we continued to work with EPCOR Distribution & Transmission Inc. on an important transmission system reinforcement to ensure continued reliable power supply to Edmonton's city centre. The $80-million project is on track to be in-service in the fall of 2008.

Ken Burgoyne

System Planning

Over the past year, we completed a major update to our 10-Year Transmission System Plan. The updated plan builds on the 20-Year Transmission System Outlook, published in 2005. The revised 10-Year Plan was filed with the EUB in December of 2006. It identifies the projected reinforcements to the transmission system that will be required over the next 10-year period. Within the document, a specific plan is provided for each region of the province as well as for the "backbone" of the system. Overall, over a 10-year period, about $3.5 billion in potential transmission system upgrades may be needed to keep pace with the forecast demand for power and to ensure Albertans continue to receive reliable electricity. This investment is in addition to the $1.2 billion in transmission system reinforcements already approved by the EUB. In the last four years, demand for power in the province has grown at a rate about equal to adding two cities the size of Red Deer to the power grid every year. Red Deer uses about 100 MW at peak demand.

In addition to the 10-Year Plan, detailed study work, which is expected to culminate in the filing of need identification documents, was initiated on a number of major projects including:

- Reinforcements to the southeastern part of the province to ensure system reliability and to facilitate the potential interconnection of wind generation developments – expected need filing in the second quarter of 2007.
- Reinforcements to the northeastern part of the province to meet load growth and enhance system reliability in the Fort McMurray area – expected need filing in late 2007.
- System expansion in the north of Fort McMurray area to provide service to a number of new oilsands developments – expected need filing in the third quarter of 2007 and second quarter of 2008.
- Reinforcement of the Edmonton Calgary backbone with a second 500-kV transmission line – studies underway.
- Stakeholder consultation began in the first quarter of 2007 on a reinforcement of the transmission system required to service proposed bitumen upgrading and refining facilities in the Fort Saskatchewan area – expected need filing in the third quarter of 2007.

Denis Forest

John Saxon

Jeff Billinton

Merchant Transmission Lines in Alberta

During the year we continued to work with proponents of merchant transmission lines. In April 2006 we filed a Need Application with the EUB for the proposed interconnection of a 300-MW merchant transmission line from Lethbridge to Great Falls, Montana. The Montana Alberta Tie Ltd. (MATL) is the proponent for this $100-million transmission line. As part of this project we developed the framework that will be used for addressing future merchant transmission proposals. We continue to work closely with MATL to facilitate the interconnection and to ensure that the project is carried out in a way that maintains the safety and reliability of the Alberta grid.

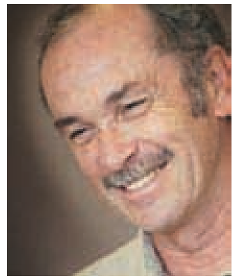
In 2006, we began working with another merchant transmission line proponent. TransCanada is proposing the NorthernLights Transmission line, a 3,000-MW high voltage direct current transmission line from Fort McMurray to the U.S. Pacific Northwest.

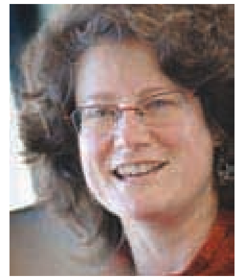
TRANSMISSION SYSTEM ACCESS

We continue to see improvements in our delivery of fair and open transmission access to customers. During 2006, we improved our project timelines while delivering a high standard of project engineering to ensure that customer needs are met and that the overall reliability of the system is maintained. As of April 1, 2007, our customer interconnections team was working on over 120 requests for system access from customers.

A collaborative effort with the EUB has supported our work to continuously improve the timeliness of access for customers. In early 2006 a new process was established and implemented whereby we would file need documents with the EUB for information purposes only on customer or generator interconnections and smaller system projects under $10 million. The EUB can still require the AESO to file a need application based on feedback the EUB receives from stakeholders. This new process ensures appropriate oversight of all transmission projects while also allowing the projects to move through the permitting process in a timely manner.


James Shen


Martin Cole


Cheryl Houlahan


John Kehler

Reliable Markets

BUILDING CONFIDENCE IN THE MARKET FRAMEWORK

Much of our effort during 2006 was directed toward implementing government policy with respect to the competitive wholesale market structure.

It is a fundamental principle that in order to achieve a fair, efficient and openly competitive market for electricity, market participants must have confidence in the market price signals. Over the past year, we've been collaborating with stakeholders on rule changes to increase confidence in the quality, fidelity and integrity of the price signal. This work has focused on what is known as merit order stabilizers of "must offer/must comply" and on removing the price distortions such as those that result from transmission must-run generation (TMR) and from not allowing imports to set price.

Proposed changes, which were agreed upon with stakeholders, would have had an immediate and significant effect on the visibility of available supply to our system controllers and the market, and enhance the credibility and stability of the pool price for electricity. In May 2006 the AESO approved a set of rules to address these issues, however, implementation of these rule changes required an amendment to the existing *Transmission Regulation*. When the amendment was delayed an alternative set of rules to address the TMR issues were developed and approved in March 2007. An alternative rule that would allow imports to set price is not yet finalized and will be the subject of future work. The approved rules will be implemented in 2007 once we have completed the required changes to our market software, system controller tools and computer systems, as well as the development and implementation of associated operating policies and procedures.

LONG-TERM ADEQUACY

Another important policy initiative that stakeholders and the AESO spent considerable time and effort on in 2006 was that of long-term adequacy of supply. The objective was to develop a series of metrics that would provide another set of market signals beyond market prices that can used by stakeholders as input into their investment decisions. These metrics can also be used by government and the AESO to determine whether or not the market and reliability objectives of the policy are being met. A set of metrics, thresholds and threshold actions have been developed and will be taken to stakeholders for further consultation in 2007.

GENERAL TARIFF APPLICATION

The EUB has scheduled a hearing in May 2007 for our general tariff application. During 2006, we had extensive consultation with respect to our 2007 general tariff application. The application proposes updates to a number of aspects of the rates and terms and conditions for system access service.

WIND GENERATION

The growth of the wind power industry is one of the success stories of Alberta's competitive electricity market. Alberta currently has more than 300 MW of wind generation power on the grid, while another 3,000 MW of wind power has applied for interconnection to the system. Significant amounts of wind generation on the system needs to be integrated carefully. In 2006, we introduced a temporary threshold of 900 MW of wind power as a prudent and balanced approach to ensure reliability while we worked with industry to address the unique aspects of integrating a large amount of wind power on Alberta's system.

In early 2007 we announced a major wind forecasting project with the Canadian Wind Energy Association (CanWEA). In March 2007 we released our discussion paper on the Market and Operational Framework for Wind Integration in Alberta. This document represents the next important step toward defining the tools and market rules for managing wind variability and ultimately making the current threshold on wind power unnecessary. We will be working with stakeholders throughout the coming year to test the concepts in this framework.

STRENGTHENING INTERTIES

Transmission interties are an important element of our competitive power market as well as the reliable operation of the electric system. From a reliability perspective, interties provide the means for the interconnected jurisdictions to provide or receive support from each other when one (or more) of the systems experience transmission problems or shortages of supply. Further, the interconnected system has a significantly greater ability to absorb the shock of system contingencies such as the loss of a critical transmission line due to lightning strikes. From a market point of view, interties can help attract investment in new power generation to Alberta, by providing access to a larger market into which surplus generation can be sold. This may enable investors to commit to the development of new supply in Alberta earlier than if they are constrained to selling their production only to the Alberta market. Interties also provide the ability to import competitively priced electricity when it is available.

The heavy demand on Alberta's transmission system, together with the lack of major system reinforcements over the last 20 years, has resulted in constraints to the capability of our existing interties with B.C. and Saskatchewan. The provincial government's *Transmission Regulation* directs the AESO to restore the interties to their original design capability. This will be achieved over time through the strengthening of the internal Alberta transmission system. Until these reinforcements are in place we have been working with stakeholders to implement innovative, short-term solutions to achieve incremental increases in the ability to export power on the existing system.

During the year, in collaboration with stakeholders and the transmission facility owners, we implemented a number of initiatives that provided incremental improvements to the capability on the Alberta-B.C. 500-kV intertie without compromising system reliability. These initiatives included the installation of capacitor banks in the Calgary area, redefining our approach to setting operating limits taking into account the real time power flows on critical transmission lines, upgrading our standards for line ratings, upgrading transmission system apparatus to remove or increase thermal operating limits and implementing remedial action schemes.

Nancy Prysko

We also initiated study work in cooperation with the British Columbia Transmission Company to evaluate the potential costs and benefits of a second intertie. This study work will be completed in 2007.

MARKET COMPLIANCE

A cornerstone of competition in an open market is the understanding and assurance that not only are the rules fair, but that any contravention of the rules is identified and corrected. We've worked diligently to ensure that market participants understand and fulfill their obligations to comply with rules. Over the last year we have continued to enhance our compliance monitoring, sanctions and enforcement rules and processes. Our experience to date shows relatively few instances of non-compliance with the rules. For those parties that were not in compliance with the rules, we responded in a manner targeted at affecting the required change in behaviour. We are pleased to report that market participants have responded positively and have taken steps to make the desired changes. After consultation with stakeholders, we further enhanced transparency and we are now publicly reporting statistics regarding rule non-compliance on our website.

Ralph Gruendel

Todd Guillet

LOOKING FORWARD

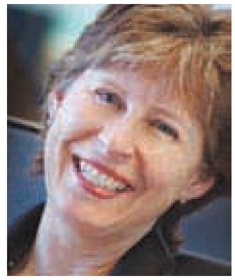
As we look forward into 2007, our market and regulatory framework work plan calls for:

- The review of our procurement practices associated with the ancillary services market in conjunction with stakeholders to ensure that these practices are consistent with a fair, efficient and openly competitive market.
- The review of current processes, standards and rules associated with the agency agreements between market participants to ensure that these agreements are consistent with a fair, efficient and openly competitive market.
- The development and implementation of rules and practices regarding the out-of-market commitment of generating units for reliability purposes.
- Consultation with stakeholders regarding a proposal to treat exports similar to imports and to address issues related to dispatchable interties. We believe it is appropriate and consistent with market policy to enable intra-hour dispatch with neighbouring jurisdictions so that imports and exports have the option to participate fully in the Alberta market.
- We are also involved in the government's consultation to review Section 6 of the *Electric Utilities Act* (see page 9).

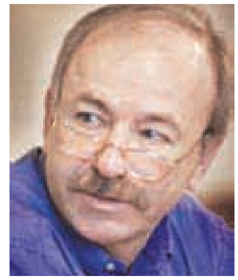
Following the completion of the Section 6 discussion, in consultation with stakeholders, we will initiate the development of the Market Roadmap. In much the same way as we develop long-term planning documents for the transmission system, the Market Roadmap is intended to provide guidance to inform market participants about developments over a five-year period. Our objective is to continue to operate the market so that reliable price signals are sent, which encourages investment and enhances the long-term viability of the market by creating greater confidence.

Given that Alberta's electricity market and the organizations supporting it have undergone significant changes over the past five years, we will undertake a comprehensive review of our authoritative documents including the AESO tariff, rules, operating policies and procedures and business practices to ensure they are consistent in terms of application and compliance. We are always working towards greater transparency and clarity for our stakeholders and this initiative is important for ensuring our published materials are easily understood and consistently applied.

Elmer Tse



Sue Asquith



Fred Ritter

Conny Taylor

Reliable People

We are fortunate to have a dedicated team at all levels of the organization. Our people, experts in their work, are focused on making sure the existing electricity market and transmission infrastructure is serving Albertans.

Early in 2007 we changed our organizational structure to ensure better alignment with our strategy and business plan. In addition, we are refining our organization's training and development strategy to make sure we are attracting and retaining the best talent.

Our executive team, and indeed all of our employees, are always working towards ensuring we have effectively engaged our stakeholders in important decisions about the Alberta electricity system and market. This team has dedicated considerable effort to improving our consultation process and our working relationships with stakeholders during the past year. Some of our key successes have included our work to involve industry stakeholders in the development of our 10-Year Transmission System Plan, as well as our new framework for reliably integrating more wind power onto the grid. Our stakeholder engagement process to review our annual budget is another area where our efforts have led to significant improvements in transparency and credibility. We continue to refine these processes to capture additional regulatory efficiencies and achieve enhanced stakeholder confidence.

As 2007 begins we continue engaging and consulting with senior level representatives from across industry and government in a process of collaboration around policy development and industry project coordination. We are refining our stakeholder engagement process to ensure we are regularly building support for the process of consultation and collaboration.

Our mandate to operate Alberta's transmission system in the public interest ensures we can lead consultations and reach decisions on infrastructure that are both balanced and fair. We believe that sharing information freely with involved stakeholders results in better and more collaborative decision making about the development of Alberta's transmission infrastructure and the operation of the system and market.

Photo on opposite page:
Jie Qiu, an EMS engineer at our system coordination centre.

Alberta Wholesale Market Statistics

Reliable 24.7.365

PRICE SUMMARY STATISTICS

The average Alberta wholesale pool price was $80.79 per megawatt hour (MWh) in 2006, a 15 per cent increase from the previous year. On-peak prices increased 21 per cent, and off-peak prices increased one per cent, compared to 2005.

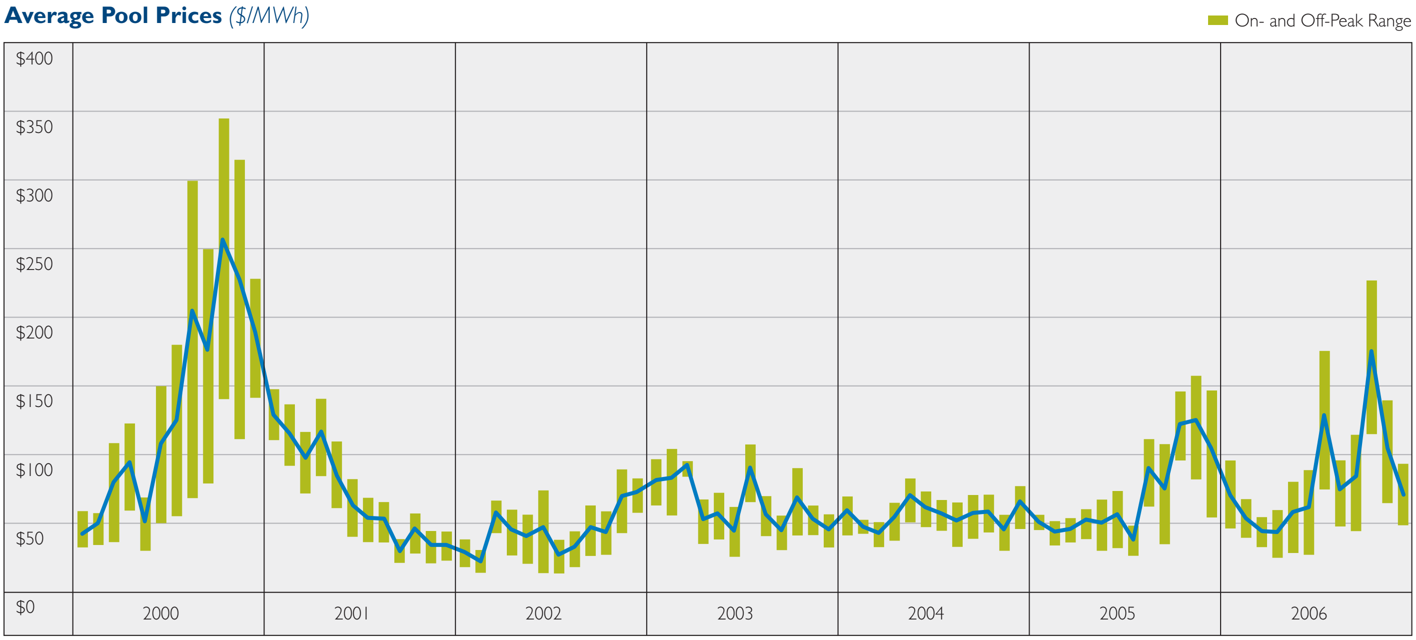
$/MWh	2000	2001	2002	2003	2004	2005	**2006**
Average	$ 133.22	$ 71.29	$ 43.93	$ 62.99	$ 54.59	$ 70.36	**$ 80.79**
On-peak	$ 181.08	$ 85.51	$ 56.04	$ 75.54	$ 64.54	$ 86.86	**$ 104.99**
Off-peak	$ 72.52	$ 53.14	$ 28.47	$ 46.98	$ 41.88	$ 49.28	**$ 49.67**
Max	$ 999.99	$ 879.20	$ 999.00	$ 999.99	$ 998.01	$ 999.99	**$ 999.99**
Min	$ 5.84	$ 5.82	$ 0.01	$ 7.07	$ 0.00	$ 4.66	**$ 5.42**

On-peak hours refer to hour ending 08:00 to hour ending 23:00, Monday to Saturday, excluding holidays. Off-peak hours refer to hour ending 01:00 to hour ending 07:00, as well as hour ending 24:00, Monday to Saturday, all day on Sunday and all day on holidays.

AVERAGE POOL PRICE INCREASES IN 2006

The average 2006 pool price was higher than previous years and the gap between on-peak and off-peak prices increased considerably. The main driver for the increase in both pool price and the on-and-off peak price gap was the number of times the pool price was at, or close to, the price cap of $1000 per MWh, due to periods of short supply. Coming off strong prices at the end of 2005, the first half of 2006 registered monthly prices similar to previous years. The average price during the first six months was $55.23 per MWh. The second half of the year saw an increase in pool price with the average price for the remaining six months reaching $105.92 per MWh. Periods in July and October were large contributors to the increase in pool price for the second half of the year. In addition to regularly scheduled generator maintenance in July and October, there were unusually high levels of unplanned generator outages. Daily average prices reached record highs during these months and, on October 4 and 5, Alberta experienced the highest recorded daily average prices to date at $533.87 per MWh and $576.11 per MWh respectively.

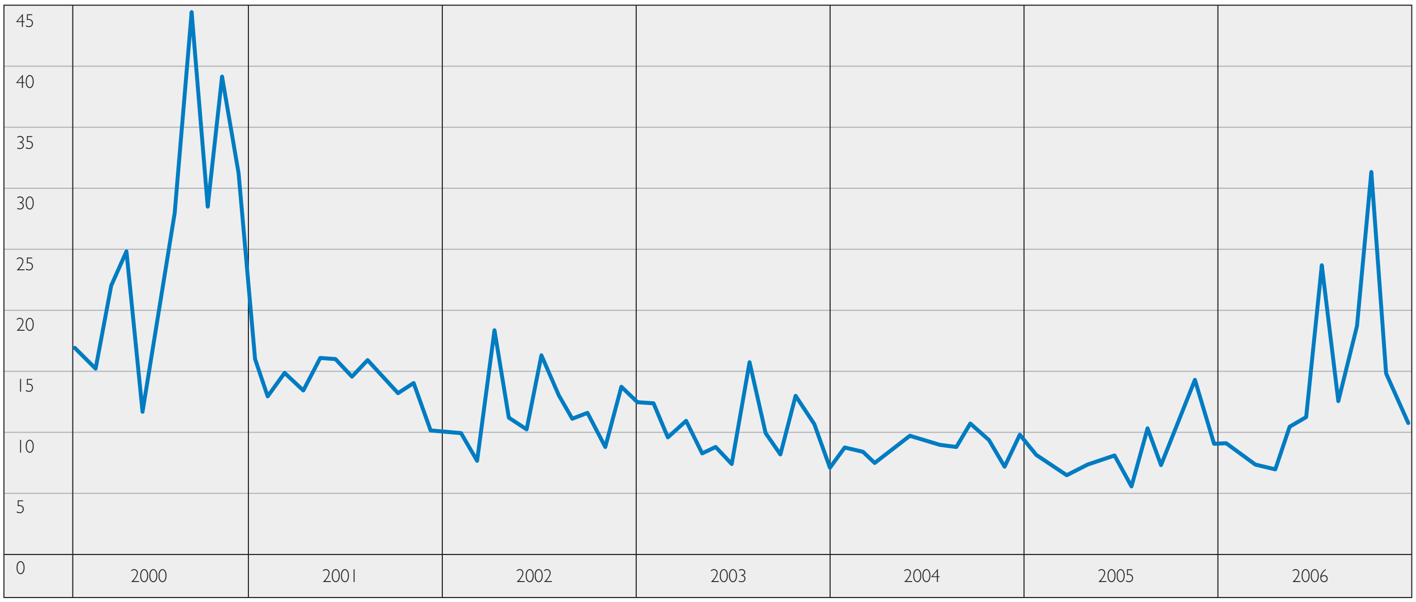
Average Pool Prices *($/MWh)*



ALBERTA HEAT RATE RISES IN 2006

In general terms the market heat rate refers to the market price of electricity expressed as a function of the market price of an underlying fuel used to produce electricity, such as natural gas. The heat rate is determined by dividing the pool price ($ per MWh) by the price of natural gas ($ per gigajoule (GJ)). The following chart illustrates the monthly average heat rate from 2000 through 2006.

Alberta Market Heat Rate *(GJ/MWh)*

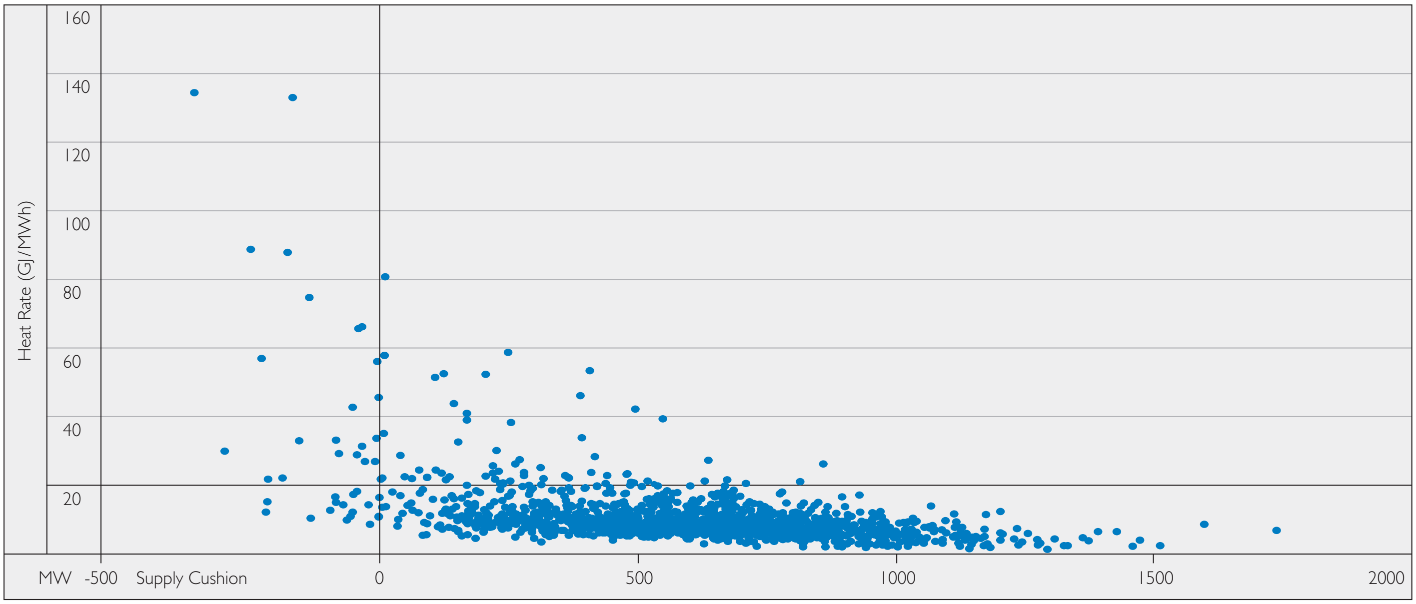


The chart illustrates the relative decline of the system heat rate from 2000 to 2005. This reflects the significant addition of more efficient cogeneration units in Alberta. Following 2005 there is a significant increase in heat rates in 2006. Higher heat rates reflect a tightening of the supply-demand balance.

SUPPLY CUSHION 2003 – 2006

"Supply cushion" represents the ability of intra-Alberta power generators to meet the demand for electricity in Alberta. It is defined as the difference between available intra-Alberta supply less the intra-Alberta demand. In this context, available intra-Alberta supply does not include energy that may be available from the interconnections or produced by intermittent power resources. The following chart shows the historical relationship between the daily supply cushion and the daily market heat rate.

Daily Heat Rate vs Daily Supply Cushion *(GJ/MWh)*

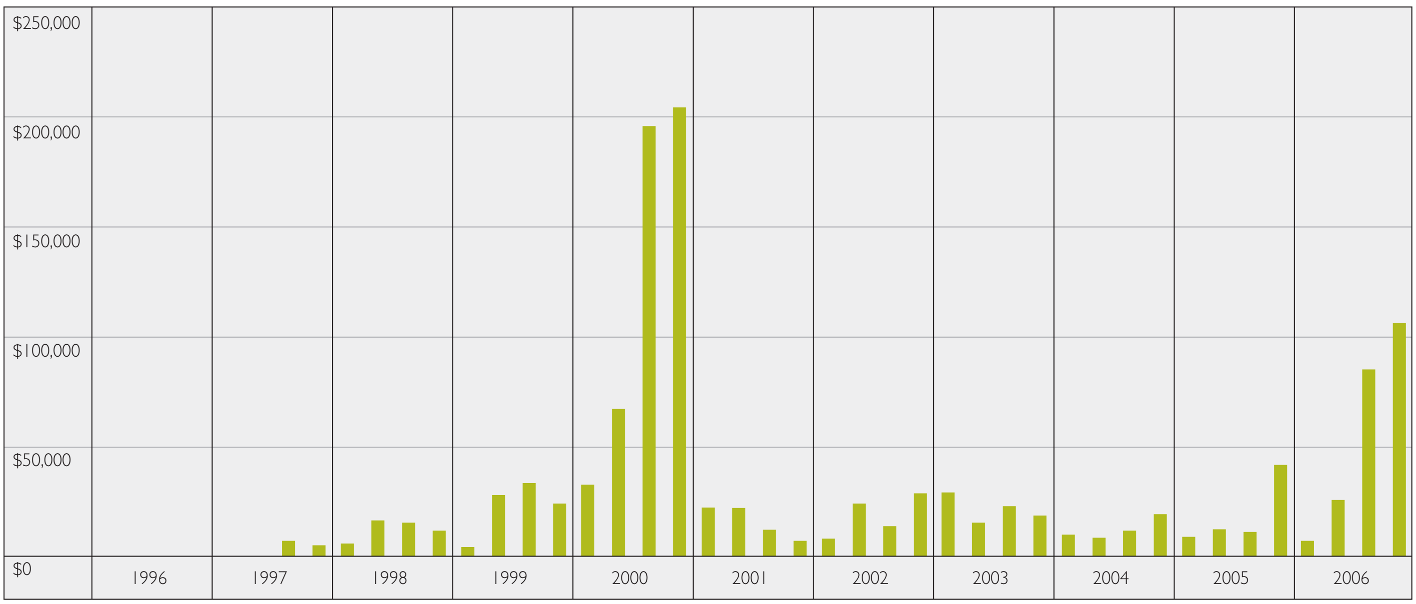


As illustrated in the previous chart, heat rates tend to remain below approximately 20 GJ per MWh as long as the supply cushion remains positive. In other words, power prices are predictable and tend to remain below approximately 20 times the underlying natural gas fuel prices as long as intra-Alberta supply is able to meet the demand for electricity in Alberta. Conversely, heat rates tend to be much less predictable and tend to increase when the supply resources required to meet demand for electricity in Alberta are dependent upon the interconnections or intermittent resources. The chart also demonstrates higher variability in heat rate when the supply cushion is negative and lower heat rate variability when there is a positive supply cushion.

OPPORTUNITY FOR NEW GENERATION INVESTMENT

As illustrated in the "supply cushion" discussion, market prices tend to remain below about a 20 GJ per MWh heat rate while the supply cushion is positive. Prices are much less predictable when incremental supply is scarce. The following chart illustrates the incremental revenue that a supplier would have received for a gas generator with variable costs equal to 20 times the price of gas, if the generator captured all profitable hours. Gas units on the system currently have variable costs much less than 20 times the cost of gas. The chart shows increasing incremental revenue in the early years with returns reaching a peak in the third and fourth quarter of 2000. Following 2000, returns decreased and moderate incremental revenue persisted until mid-2005. The end of 2005 and the second half of 2006 show increasing incremental revenues, reflecting more frequent instances of situations when incremental supply was scarce and prices reflected that scarcity. This condition is a signal for both the need and opportunity for new generation investment in Alberta.

Incremental Revenue, Per MW, Per Quarter Associated with a Market Heat Rate in Excess of 20GJ/MWh *($/MW)*



DEMAND CONTINUES TO RISE

Demand for electricity continues to increase as the Alberta Internal Load (AIL) grew by 4.68 per cent in 2006. Overall growth in industry and increases in population continued to drive higher demand for electricity. The annual load factor remained high, highlighting the fact that Alberta load does not vary significantly between times of peak and off-peak demand. A new record AIL demand peak of 9,661 MW was set on November 28, 2006.

Demand Summary Statistics

Category	2000	2001	2002	2003	2004	2005	**2006**
Alberta internal load *(MWh)*	54,052,857	54,464,397	59,427,895	62,714,018	65,261,309	66,266,568	**69,369,910**
Average hourly load *(MW)*	6,154	6,217	6,784	7,159	7,430	7,565	**7,919**
Maximum hourly load *(MW)*	7,785	7,934	8,570	8,786	9,236	9,580	**9,661**
Minimum hourly load *(MW)*	4,999	5,030	5,309	5,658	6,017	6,104	**6,351**
Year-over-year load growth	–	0.76%	9.11%	5.53%	4.06%	1.54%	**4.68%**
Load factor	79.0%	78.4%	79.2%	81.5%	80.4%	79.0%	**82.0%**

EXPORT CAPABILITY INCREASES IN SECOND HALF OF 2006

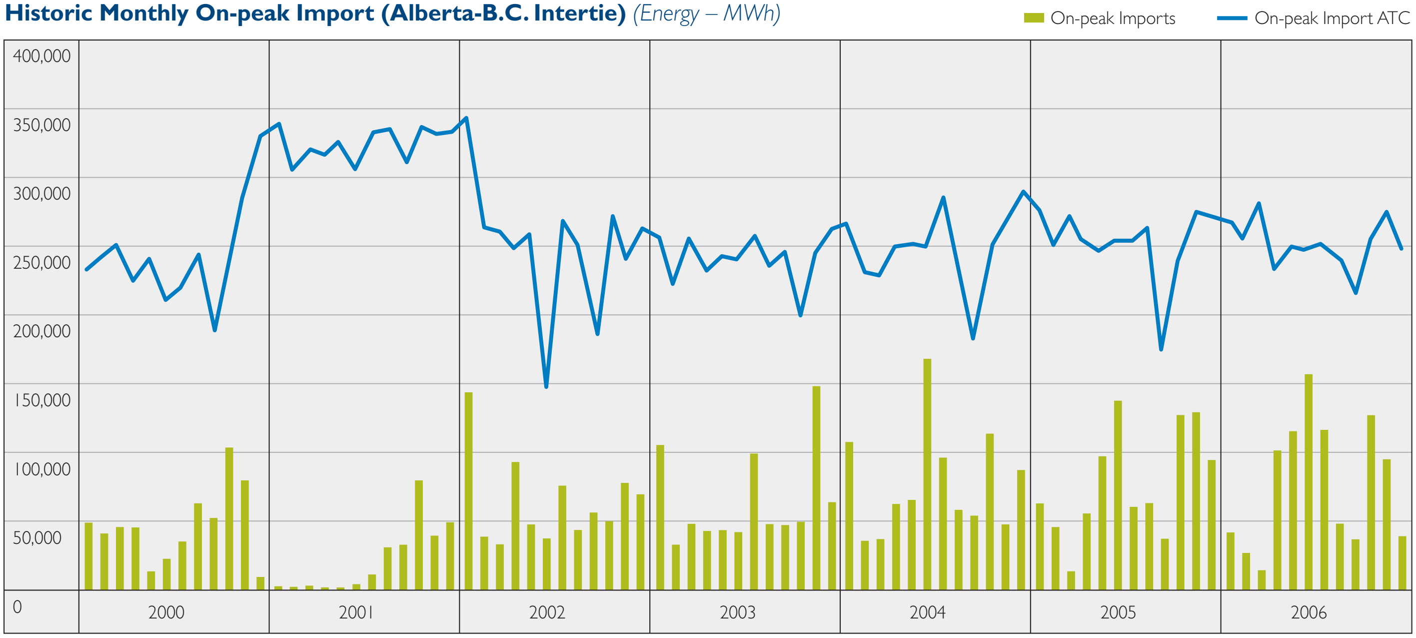
The interconnections with B.C. and Saskatchewan are essential to a well functioning market in Alberta as they facilitate energy imports during times of tight supply and energy exports when Alberta is in surplus. Typically, energy is imported during the day and exported during the evening. In 2006 both total imports and total exports decreased from 2005 levels, with total imports decreasing one per cent and total exports decreasing 53 per cent. Alberta continues to be a net importer of electricity.

Interconnection Statistics

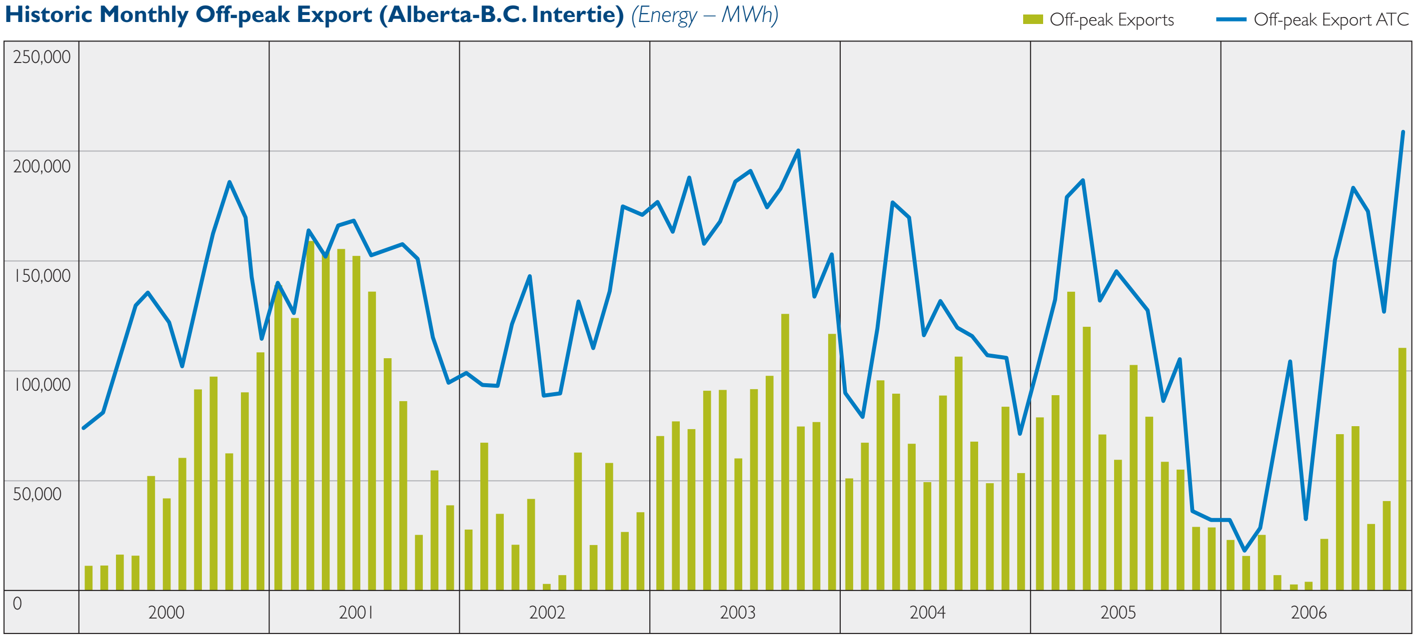
(MWh)	2000	2001	2002	2003	2004	2005	**2006**
Imports on B.C. intertie	564,238	232,052	895,753	898,717	1,073,471	1,070,848	**1,101,207**
Imports on Sask. intertie	742,704	676,130	239,406	428,949	418,267	463,726	**415,828**
Total imports	**1,306,942**	**908,182**	**1,135,159**	**1,327,666**	**1,491,738**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

Energy flows on the interconnections are limited by the Available Transfer Capability (ATC). The following charts illustrate how the interconnection with B.C. has been utilized by comparing the ATC with on-peak import and off-peak export volumes. During on-peak hours, 2006 was similar to previous years with monthly import ATC levels well above actual monthly import volumes. This indicates that there is additional ability to receive power from B.C. during on-peak hours. Off-peak hours saw high utilization in the latter half of 2005 and first quarter of 2006 as ATC levels were well below normal. The remainder of 2006 saw under utilized export capability. Ongoing initiatives restored ATC and low export volumes were contributing factors.

Historic Monthly On-peak Import (Alberta-B.C. Intertie) *(Energy – MWh)*



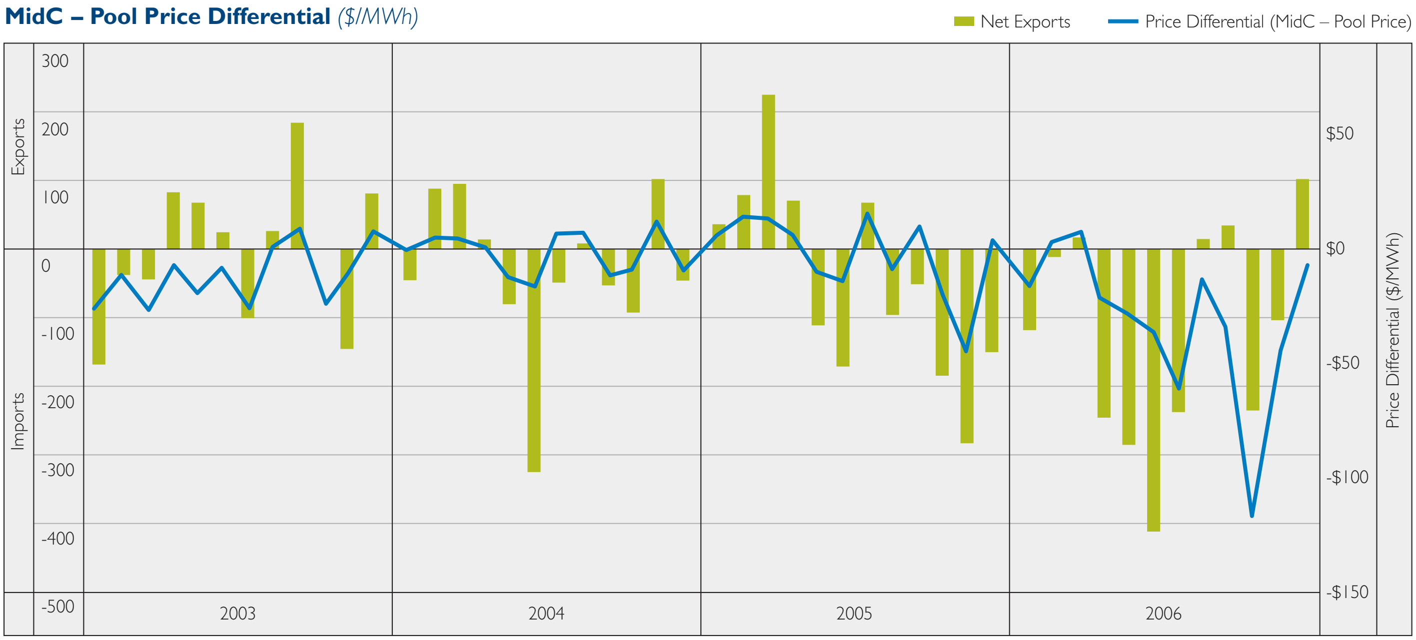
Historic Monthly Off-peak Export (Alberta-B.C. Intertie) *(Energy – MWh)*



TRADE ON ALBERTA-B.C. INTERCONNECTION REFLECTS MARKET PRICES

The Alberta market is linked with other jurisdictions by way of its interconnections to B.C. and Saskatchewan. The strongest linkage is between Alberta and the Pacific Northwest via our interconnection with B.C. The primary electricity price signal in the Pacific Northwest is the Mid-Columbia electricity price index (MidC). This chart shows the spread between the MidC and the Alberta pool price in C$ per MWh from 2003 to 2006. It also illustrates the effect such price differentials may have on power flows between these jurisdictions (notwithstanding other considerations such as capacity limitations). In particular, the analysis only incorporates flows of energy that occur when the price differential between MidC and the pool price is greater than $10 per MWh, as it is unlikely price differentials smaller than this would induce energy flows in either direction. In general, this analysis suggests a correlation between price differentials and energy flows. For example, the analysis shows that, in Q2 and Q4 of 2006, pool price tended to be significantly higher than MidC prices. During these months, Alberta was generally a net importer of electricity.

MidC – Pool Price Differential *($/MWh)*



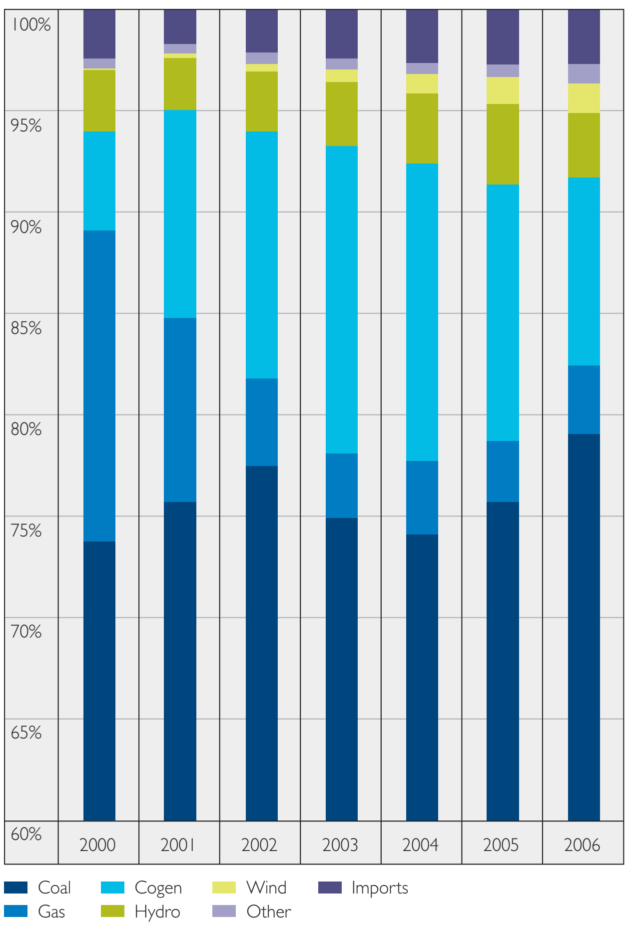
ENERGY PRODUCTION BY FUEL SOURCE

Since 2000, Alberta has added significant cogeneration and wind generation capacity, as well as the Genesee 3 coal-fired unit. There have also been retirements of coal-fired generation capacity during this period including Battle River units 1 and 2 in 2000 and the Wabamun 1 and 2 units at year end 2004. The gas-fired Clover Bar units were retired in 2005. The following chart shows that the proportion of total energy produced by coal and wind increased in 2006. Conversely, the proportion of total energy from gas-fired cogeneration units decreased.

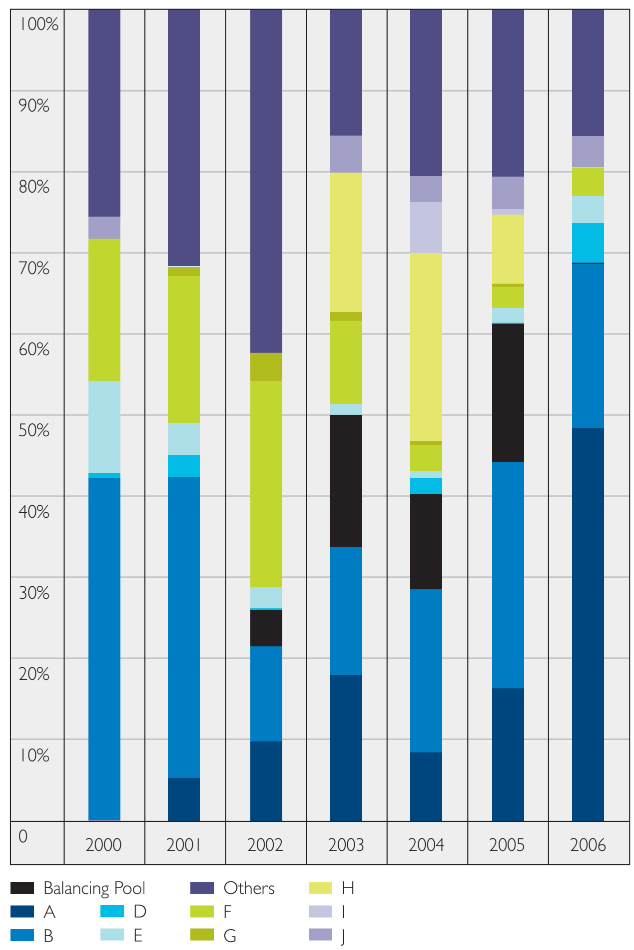
PRICE SETTER BY COMPANY

This chart looks at the frequency that each firm set price from 2000 to 2006. It would appear that from 2000 through 2004 there was a trend toward a more diffuse distribution of price setters. In 2005 and, more noticeably in 2006, there was a marked departure from this trend. There has been a significant change in the amount of generation owned or controlled by different firms in the market in 2006 due to the Market Achievement Plan (MAP) auction of the Sheerness generating facilities and the completion of a number of other private transactions. It would appear that these changes, as well as other market factors, have resulted in a less diffuse distribution than in the last few years.

Energy Production *(MWh)* **by Fuel Source**



Price Setter by Company



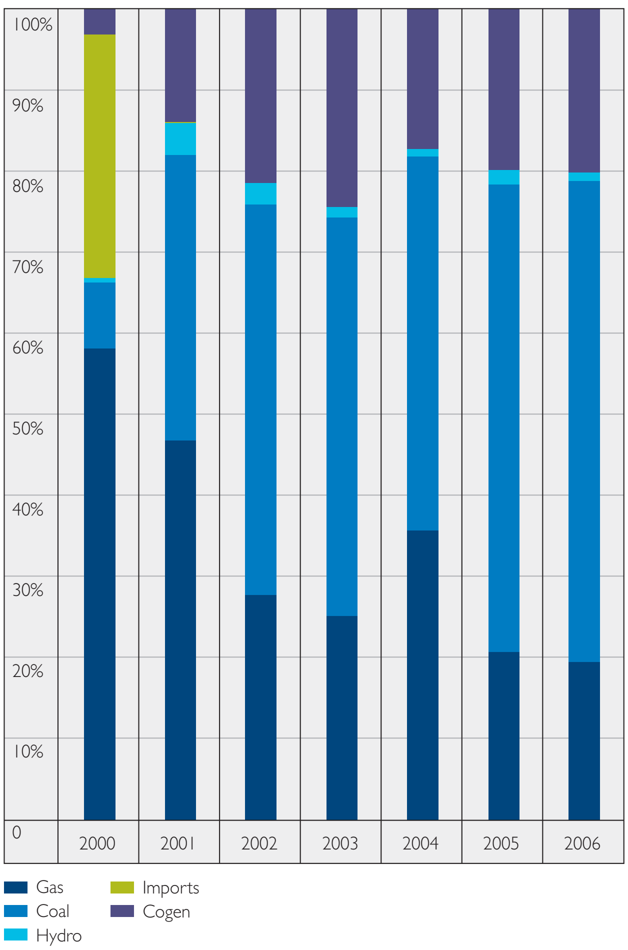
PRICE SETTER BY FUEL SOURCE

There was little change in price setting by fuel source in 2006. Coal units continued to dominate, setting the price 60 per cent of the time. Dedicated gas and gas cogeneration units set the price for most of the remaining time, with about a 20 per cent share each. Hydro units continue to set price a relatively small amount of time.

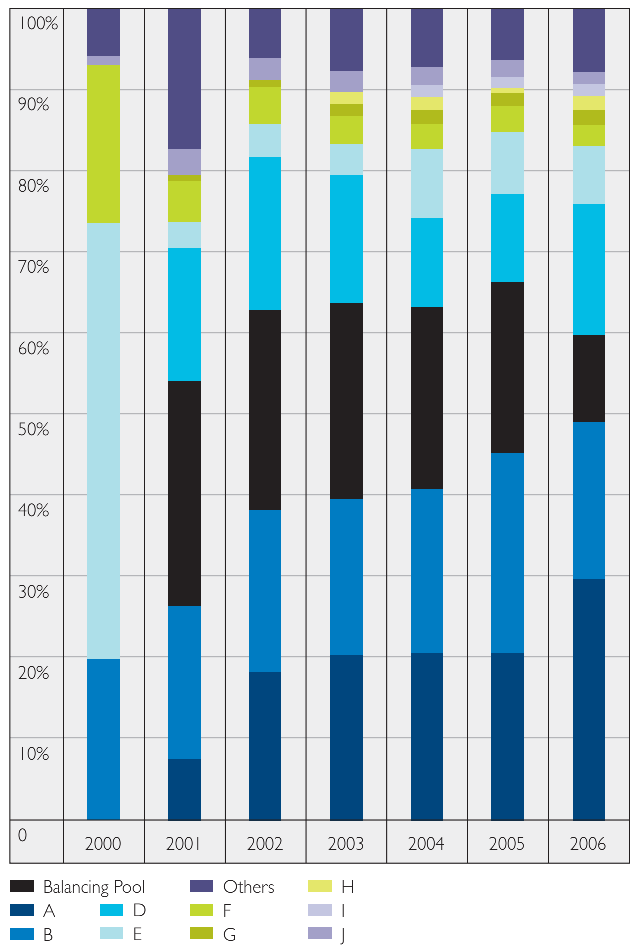
ENERGY PRODUCTION BY COMPANY

This chart shows the relative Alberta electricity market share as determined by the energy production by company. We note that prior to 2006 there had been little change in relative market share by company since 2001. During 2006 there were a number of changes in the volume of generation owned by different entities in the market, which significantly changed the market share of these companies. In terms of total volumes generated, the market continues to be dominated by five or six different companies.

Price Setter by Fuel

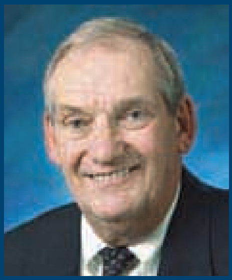


Energy Production by Company *(MWh)*



AESO Board Members

Harry Hobbs



Bill Burch

Dr. Ron George

Nancy Laird

Harry Hobbs

Board Chair

Member of the Audit Committee and the Human Resources, Compensation and Governance Committee

Mr. Hobbs was appointed Chair of the Board effective June 1, 2006. He has been a member of the AESO Board since May 2004. Mr. Hobbs is the 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 gained extensive experience in commercial and customer interests, government and regulatory affairs, strategic planning, environment, socio-economics, rates and tariffs, economic planning, corporate communications and community investment during his 25-year tenure with Foothills Pipeline Ltd.

Bill Burch

Chair of the Audit Committee and member of the Human Resources, Compensation and Governance Committee

Mr. Burch joined the AESO Board in 2001. Mr. Burch is a chartered accountant with extensive background in the finance industry. Since retiring as partner at Price WaterhouseCoopers he has served as a board member for Floron Flood Services and the Capital Health Region.

Ron George

Member of the Audit Committee and the Human Resources, Compensation and Governance Committee

Mr. George (Ph.D) joined the AESO Board in 1999. He has more than 40 years experience in the information technology business and works as a consultant, teacher, entrepreneur and mentor. He is also an executive-in-residence at the University of Calgary, Faculty of Management. Mr. 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.

Nancy Laird

Chair of the Human Resources, Compensation and Governance Committee and member of the Audit Committee

Ms. Laird has been a member of the AESO 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.

AESO Executive Team

Back row, standing: Neil Millar, Heidi Kirrmaier, Kent McDuffie, Dale McMaster, Warren Frost, Sandra Scott *Middle row, seated:* David Erickson, Wayne St. Amour *Front row, seated:* Todd Fior, Cliff Monar

Executive

Dale McMaster

President & Chief Executive Officer

As president and chief executive officer Mr. McMaster is responsible for ensuring the AESO effectively carries out its mandate to ensure the safe, reliable and economic operation and development of the provincial power grid in addition to operating the province's fair, efficient and openly-competitive wholesale electricity market. An electrical engineer, Mr. McMaster brings 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 and 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. He brings 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 expanded his responsibilities 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 as well as the load settlement function. He has more than 15 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 operational planning and ensuring the safe, reliable and economic operation of Alberta's interconnected power system. Mr. Frost is an electrical engineer with 29 years experience in the electricity industry including policy development, system operations, transmission asset management, regulatory and customer service. Prior to joining the AESO he was director, infrastructure policy in the electricity division of Alberta Energy. Mr. Frost was appointed to his current role in July 2005.

Executive *(continued)*

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 Energy and Utilities Board. 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.

Kent McDuffie

Vice-President, Market & Regulatory Framework

Mr. McDuffie is responsible for strategic direction of the AESO's commercial, market and regulatory framework teams. His position is a new role for the organization and reflects an increased focus on policy and legislative areas. Mr. McDuffie brings significant experience in power markets including roles as vice-president of power trading for Engage Energy as well as similar positions with Houston-based El Paso Energy and Duke/Louis Dreyfuss LLC. He joined the AESO in 2005 as vice-president of market services. Mr. McDuffie was appointed to his current role in February 2007.

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 applications to upgrade and strengthen the provincial power system. He brings over 24 years of industry experience to his role in a number of transmission planning, regulatory and customer service 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.

Executive *(continued)*

Cliff Monar

Vice-President, Market Services

Mr. Monar is responsible for the design and operation of the energy and operating reserves markets as well as the development of market rules. He also oversees the procurement of ancillary services. Mr. Monar brings 20 years of industry experience in areas such as business development, energy trading and portfolio management, operations, 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 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

Mr. St. Amour (Ph.D) is responsible for the strategic direction of the human resources, stakeholder relations/corporate communications and customer service areas of the AESO. He has more than 25 years of senior level experience in strategic management, organizational learning, knowledge management, HR, marketing, corporate communication 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. Mr. St. Amour was appointed to his current position in October 2006.

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

This management discussion and analysis of financial condition and results of operations (MD&A) should be read in conjunction with the Alberta Electric System Operator (AESO) audited financial statements for the years ended December 31, 2006 and 2005 and accompanying notes. The MD&A and financial statements are reviewed and approved by the AESO Board. The AESO financial statements have been prepared in accordance with Canadian generally accepted accounting principles 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 regulating and administering load settlement.

1. AESO GOVERNANCE

The AESO is governed by the AESO Board, whose members are appointed by Alberta's Minister of Energy (the Minister) and are independent of any person or entity having a material interest in the Alberta electric industry. In accordance with the AESO's bylaws, the AESO Board must recommend to the Minister individuals to be appointed as Board members and may recommend to the Minister an individual to be designated as chair. The AESO Board is to have no more than nine members.

The AESO Board is responsible for overseeing the business and affairs of the AESO. The AESO Board is actively involved in the strategic planning process and discusses and reviews all materials relating to the strategic plan with management. At least one Board meeting per year is devoted to discussing and considering the strategic plan, which takes into account the risks and opportunities of the AESO. On an ongoing basis, the AESO Board is involved in the financial oversight of all corporate operations, including cost and risk management.

The AESO Board has two standing committees:

- The **Audit 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, with a view to ensuring best practices are followed.
- The **Human Resources, Compensation and Governance Committee** provides consultation, advice and recommendations to the AESO Board on 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 the corporate governance practices.

Each AESO Board committee operates in accordance with a charter that has been approved by the AESO Board.

2. 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 service costs. The overall revenues and costs of the AESO are as follows:

(Millions) Years ended December 31	**2006**	2005	Variance	% Variance
Transmission revenue	**$ 946.3**	$ 845.6	$ 100.7	12
Energy market charge	**12.7**	12.6	0.1	1
Load settlement	**4.8**	2.7	2.1	78
Interest and other income	**1.3**	1.2	0.1	8
Wire costs	**$ 444.9**	$ 420.0	$ 24.9	6
Ancillary services	**235.2**	189.8	45.4	24
Line losses	**231.9**	200.8	31.1	15
General and administrative	**39.9**	38.6	1.3	3
Amortization	**9.2**	6.6	2.6	39
Other industry costs	**3.6**	5.3	(1.7)	(32)
Interest expense	**0.4**	1.0	(0.6)	(60)

3. 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	**2006**	2005	Variance	% Variance
Transmission revenue	**$ 946.3**	$ 845.6	$ 100.7	12
Interest and other revenue	**0.8**	0.8	–	–
Total transmission revenue	**$ 947.1**	$ 846.4	$ 100.7	12

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). 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. Starting in 2006, Rate Rider E was implemented 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.

On an annual basis and for non-transmission line loss rate categories, the AESO files a retrospective deferral account reconciliation application with the EUB 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 revenue in 2006 of $0.8 million relates to the interest earned on transmission customer security deposits, customer contribution funds held by the AESO awaiting transmission facility owner (TFO) billings and transmission deferral funds held awaiting the annual deferral account reconciliation for years prior to 2006.

Deferral Summary

(Millions) Years ended December 31	**2006**	2005
Collections	**$ 940.1**	$ 827.6
Costs	**947.1**	846.4
Transmission revenue	**(7.0)**	(18.8)
Deferral account payable, beginning of year	**11.3**	30.1
Deferral account payable, end of year	**$ 4.3**	$ 11.3

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, 2006 was reduced to $4.3 million from $11.3 million payable at the end of 2005 as a result of 2006 transmission collections being $7.0 million less than transmission costs.

The transmission deferral balance of $4.3 million at December 31, 2006 is comprised of four components:

- The net revenue and cost adjustments of $15.3 million payable to transmission customers that relate to production years prior to 2006, 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 2006 for the current year production have contributed to a transmission deferral account balance of $11.6 million receivable. The 2007 first quarter Rate Rider C and E rates were set to bring the deferral account balance to zero for the 2006 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.
- Since June 2005, the AESO has been in receipt of $31.0 million of transmission settlement funds awaiting final deferral account reconciliation and subsequent refunds to transmission customers. These funds were used to offset otherwise required debt balances. An imputed interest amount of $1.7 million for 2005 and 2006 is payable to transmission customers.

Energy Market

Revenue Summary

(Millions) Years ended December 31	**2006**	2005	Variance	% Variance
Energy market revenue	**$ 12.7**	$ 12.6	$ 0.1	1
Interest and other revenue	**0.5**	0.4	0.1	25
Total energy market revenue	**$ 13.2**	$ 13.0	$ 0.2	2

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 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 will be 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 third consecutive year, the energy market trading charge was 11.1 cents per megawatt hour traded.

Deferral Summary

(Millions) Years ended December 31	**2006**	2005
Collections	**$ 13.9**	$ 13.2
Costs	**13.3**	13.0
Energy market deferred revenue	**0.6**	0.2
Deferral account payable, beginning of year	**6.0**	5.8
Deferral account payable, end of year	**$ 6.6**	$ 6.0

The energy market deferral amount at December 31, 2006 is $6.6 million payable compared to $6.0 million payable at the end of 2005. The increase of $0.6 million during 2006 was a result of:

- Surplus collections in energy market trading charges of $1.3 million, offset by
- Amortization of system controller capital assets of $0.7 million.

Of the December 31, 2006 deferral surplus of $6.6 million, $6.4 million is payable to energy market participants and is incorporated into the trading charge requirements for 2007. The remaining deferral balance of $0.2 million relates to the system controller capital assets to be depreciated in 2007.

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 2006, the MSA's portion of the total energy market trading charge of 12.9 cents per megawatt hour was 1.8 cents per megawatt hour, with the remaining 11.1 cents per megawatt hour for the AESO's operations. This compares to a MSA charge of 2.3 cents per megawatt hour in 2005.

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, 2006 there was a $0.02 million shortfall in MSA collections, compared to a surplus of $0.2 million at December 31, 2005.

Load Settlement

Revenue Summary

(Millions) Years ended December 31	2006	2005	Variance	% Variance
Load settlement recovery	**$ 4.8**	$ 2.7	$ 2.1	78
Interest and other revenue	**0.0**	0.0	0.0	–
Total load settlement revenue	**$ 4.8**	$ 2.7	$ 2.1	78

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 corporate shared services and an allocation of amortization for the recovery of capital assets.

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

Deferral Summary

(Millions) Years ended December 31	2006	2005
Collections	**$ 5.8**	$ 1.7
Costs	**4.8**	2.7
Load settlement deferred revenue (revenue)	**1.0**	(1.0)
Deferral account (receivable) payable, beginning of year	**(0.2)**	0.8
Deferral account payable (receivable), end of year	**$ 0.8**	$ (0.2)

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

4. 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 generally accepted accounting principles. This differs from the production period reporting in the AESO's General Tariff Applications.

(Millions) Years ended December 31	2006	2005	Variance	% Variance
Wire costs	**$ 444.9**	$ 420.0	$ 24.9	6
Ancillary services costs	**$ 235.2**	$ 189.8	$ 45.4	24
Line losses	**$ 231.9**	$ 200.8	$ 31.1	15
Other industry costs	**$ 3.6**	$ 5.3	$ (1.7)	(32)

Wires Costs

Wires costs represent the amount paid to the owners of the transmission facilities in accordance with their EUB-approved tariffs and are not controllable costs of the AESO. The costs increased $24.9 million or six per cent compared to 2005 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 may be exchange-traded or over-the-counter contracts, for generation capacity and for load reduction capabilities. The AESO has entered into various contracts for ancillary services that include operating reserves, transmission must-run, under-frequency mitigation and system restoration.

The cost of ancillary services increased to $235.2 million in 2006 compared to $189.8 million in 2005, an increase of $45.4 million or 24 per cent. This increase is mainly due to the changes in costs associated with operating reserves offset by a reduction in costs for transmission must-run services as described on the following page.

Operating Reserves are comprised of three types of active reserves, with the minimum levels of operating reserves 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 their generator up 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 operating reserve providers are paid their accepted offer price for the ability of the AESO to utilize their energy as reserves. The majority of operating reserve offer prices are indexed to the pool price.

Operating reserves costs increased to $183.0 million in 2006 compared to $122.3 million in 2005, an increase of $60.7 million or 50 per cent. While volumes remained comparable to 2005, the increase in costs in 2006 is attributable to general increases in pool price and an increase in pool price volatility in 2006 relative to 2005, which tends to put upward pressure on operating reserves costs.

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

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

TMR costs decreased to $41.3 million in 2006 compared to $56.4 million in 2005, a decrease of $15.1 million or 27 per cent. Contributing to the decrease are changes that occurred with market heat rates and gas prices. In 2006, the market heat rate and average gas price were 13.99 and $6.17 per gigajoule respectively compared to 8.23 and $8.28 in 2005. This represents a 70 per cent increase in the market heat rate and a 25 per cent decrease in the average gas price, compounded to contribute to the overall decrease in TMR costs. In addition, the AESO incurred a one-time cost in 2005 to postpone the decommissioning of the Rossdale generation facility; this facility has been contracted to provide TMR services on a short-term basis.

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 2006 was $231.9 million compared to $200.8 million in 2005, an increase of $31.1 million or 15 per cent. In 2006, the volumes of line losses remained unchanged from 2005 at approximately 2.9 terawatt hours annually.

The average hourly pool price, at which losses are valued, increased by 16 per cent from 2005 causing line loss costs to increase by 15 per cent. The average hourly pool price in 2006 was $81 per megawatt hour compared to $70 per megawatt hour in 2005.

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 EUB-related costs.

Other industry costs decreased in 2006 by $1.7 million or 32 per cent from $5.3 million in 2005 to $3.6 million in 2006. This decrease is a result of a fluctuation in annual AESO regulatory proceedings and the timing of regulatory cost approval.

General and Administrative Costs

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

(Millions) Years ended December 31	**2006**	2005	Variance	% Variance
Salaries and benefits	**$ 27.5**	$ 26.8	$ 0.7	3
Professional fees and consulting	**4.8**	4.5	0.3	7
Office and administrative	**7.7**	7.3	0.4	5
Total general and administrative	**40.0**	38.6	1.4	4
Amortization	**9.2**	6.6	2.6	39
Interest	**0.4**	1.0	(0.6)	(60)
Total general and administrative costs	**$ 49.6**	$ 46.2	$ 3.4	7

Salaries and Benefits

The increase is due to a full year's salary and benefits for staff hired in 2005, staff hired during 2006 and annual compensation adjustments for staff. Included in the salaries and benefits in 2005 are one-time corporate reorganization costs, in the absence of which, the variance between 2006 and 2005 would have been $2.6 million or 10 per cent.

Professional Fees and Consulting

Consultants are required to supplement staff during peak work requirements and to provide technical expertise. In 2006, consulting activities focused on transmission-related initiatives and information technology technical support consistent with 2005.

Office and Administrative

The increase is a result of slight increases to several cost areas with more notable increases in corporate travel and information technology representing an overall increase of $0.4 million or 5 per cent.

Amortization

Amortization of capital assets in 2006 includes the full year of amortization for the 2005 additions, new additions in 2006 offset by a reduction in amortization for assets that became fully amortized in 2006. Capital expenditures in 2006 were $24.4 million, of which $1.8 million are work-in-progress assets that are not yet subject to amortization and $18.7 million that relates to the system coordination facility that was commissioned in December 2006.

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. During 2006, the AESO was in receipt of $31.0 million of transmission settlement funds awaiting final deferral account reconciliation for refunds to transmission customers. These funds were 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 $1.7 million.

5. 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)	General and Administrative		Amortization		Interest		Total	
Years ended December 31	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005
Transmission	**$ 28.6**	$ 27.8	**$ 3.0**	$ 2.3	**$ (0.1)**	$ 0.4	**$ 31.5**	$ 30.5
Energy market	**8.9**	8.7	**4.3**	3.9	**0.1**	0.4	**13.3**	13.0
Load settlement	**2.5**	2.1	**1.9**	0.4	**0.4**	0.2	**4.8**	2.7
Total	**$ 40.0**	$ 38.6	**$ 9.2**	$ 6.6	**$ 0.4**	$ 1.0	**$ 49.6**	$ 46.2

General and Administrative

The percentage allocation of general and administrative costs by function required minor adjustments in 2006 to reflect changing operational activities and result in comparable allocations to 2005.

Amortization

The notable changes in the amortization are a result of the first full year of amortization on the $13.0 million of capital expenditures that occurred in 2005. In particular, the AESO commissioned a new $9.5 million computer system in November 2005 that is primarily associated with the load settlement function. In December 2006, the system coordination facility was commissioned, which resulted in one month of amortization in 2006. The costs associated with the system coordination facility are recovered from the transmission function and, to a lesser extent, from the energy market function.

Interest

Overall, the interest expense in 2006 is significantly lower than 2005 due to the use of $31.0 million of transmission settlement funds awaiting final deferral account reconciliation to offset otherwise required debt balances. Imputed interest income and expense amounts were determined and allocated to the appropriate function. An imputed interest income amount of $1.3 million for 2006 is payable to transmission customers.

In comparing interest costs in 2006 and 2005 on a function basis, the debt financing for the three functions changed as a result of the underlying operational requirements.

6. FINANCIAL POSITION AND LIQUIDITY

(Millions) Years ended December 31, 2006	**2006**
Cash, beginning of year	**$ 30.9**
Operating activities	**114.2**
Investing activities	**(24.4)**
Financing activities	**6.9**
Cash, end of year	**$ 127.6**

The cash balance as at December 31, 2006 was $127.6 million compared to $30.9 million at December 31, 2005. The increase is primarily the result of the following:

- **Operating activities** provided cash of $114.2 million in 2006. The increase is mainly attributed to a change in non-cash working capital of $105.0 million.
  - Accounts receivable balance at December 31, 2006 was $191.8 million compared to $108.4 million at December 31, 2005, an increase of $83.4 million. Based on the number of business days in December 2006, the cash settlement for the month of November occurred on January 2, 2007. As a result, the accounts receivable balance at the end of 2006 includes two months of accruals as opposed to one month in 2005 for the transmission settlement and the energy market trading charge.
  - Accounts payable balance at December 31, 2006 was $308.4 million compared to $113.8 million at December 31, 2005, an increase of $194.6 million. Similar to accounts receivable, the accounts payable balance at the end of 2006 includes two months of transmission settlement accruals, for the months of November and December. In addition, the AESO received early payment for $87.8 million of energy market settlement funds for the January 2, 2007 cash settlement.
  - Participants' security deposits balance at December 31, 2006 was $1.7 million compared to $7.4 million at December 31, 2005, a decrease of $5.7 million. The balance of security deposits held by the AESO is solely dependent on how participants elect to meet the AESO's security requirements.
- **Investing activities** used cash of $24.4 million for capital asset additions.
- **Financing activities** provided cash of $6.9 million in 2006. The primary financing activities were an increase in bank debt of $12.5 million offset by a decrease in deferral accounts payable to customers of $5.5 million.

As at December 31, 2006, the AESO had the following credit facilities available to fund general operating and capital activities:

(Millions) Year ended December 31, 2006	**Total**	Available	Used
Term revolving facility	**$ 50.0**	$ 49.0	$ 1.0
Demand revolving facility	**$ 40.0**	$ 18.4	$ 21.6
Demand non-revolving facility	**$ 20.0**	$ 0.0	$ 20.0
Demand treasury risk management facility	**$ 9.0**	$ 9.0	$ 0.0

The term revolving facility includes a $30.0 million letter of credit at December 31, 2006 which was issued as security for the AESO's operating reserve procurement.

7. 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 EUB.

For transmission-related activities in 2007, the AESO's General Tariff Application revenue requirement filed with the EUB in November 2006 was for $872.5 million compared to $758.8 million in 2006. This revenue requirement includes costs related to wires, ancillary services, line losses, other industry and general and administrative costs. This $113.7 million or 15 per cent increase is primarily due to a forecasted increase in ancillary services and line losses costs in 2007 as a result of a forecasted increase in pool prices.

For energy market activities, the annual costs are forecasted to increase to $15.7 million in 2007 from the 2006 actual costs of $13.3 million, a $2.4 million or 18 per cent increase. This forecasted increase is a combination of anticipated cost increases for salaries and benefits and telecommunication and information technology areas. With the combination of this forecasted cost increase and the 2006 deferral balance, the AESO's portion of the 2007 energy market trading charge will remain unchanged from 2006 at 11.1 cents per megawatt hour. In 2007, the total energy market trading charge will be 13.6 cents per megawatt hour, a change from the 2006 charge of 12.9 cents per megawatt hour due to an increase in the MSA's charge.

For load settlement in 2007, it is anticipated that the rule making and audit responsibility for the load settlement rules will be transitioned to the EUB to facilitate convergence of gas and electricity rules. The compliance monitoring, investigation and reporting functions will continue to be carried out by the AESO.

In response to the increasingly complex operational requirements and security for the operations of the AIES, the AESO will begin an upgrade to the Energy Management System (EMS) in 2007. This upgrade 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. The scope and anticipated costs for this initiative are currently being assessed.

Continuing into 2007, the AESO will work with industry on the implementation of Alberta's Electricity Policy Framework to provide refinements to the wholesale market structure. The costs related to this initiative are currently being assessed.

8. 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 Code of Conduct serves as a framework for AESO officers, employees and contractors of the AESO 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 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 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.

9. 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.

10. ADDITIONAL INFORMATION

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

Management's Responsibility for Financial Reporting

The financial statements included in the annual report are the responsibility of management and have been approved by the Alberta Electric System Operator Board. These financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles, 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 Alberta Electric System Operator's assets are safeguarded, that transactions are properly authorized and that financial information is relevant, accurate and available on a timely basis.

The financial statements have been examined by Deloitte & Touche LLP, the Alberta Electric System Operator's external independent auditors. 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.

M. Dale McMaster, P. Eng.
President and Chief Executive Officer

David Erickson, CA
Senior Vice-President and Chief Operating Officer

Auditors' Report

To the Members of the Alberta Electric System Operator Board

We have audited the balance sheets of the Alberta Electric System Operator as at December 31, 2006 and 2005 and the statements of operations 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, 2006 and 2005 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

February 2, 2007

Balance Sheet

As at December 31 (in thousands of Canadian dollars)	**2006**	2005
Assets		
Current assets		
Cash	**$ 127,651**	$ 30,938
Accounts receivable *(note 4)*	**191,762**	108,383
Prepaid expenses and deposits	**2,489**	2,026
MSA deferral account receivable	**16**	–
	321,918	141,347
Capital assets *(note 5)*	**43,970**	28,785
	$ 365,888	$ 170,132
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities *(note 6)*	**$ 308,428**	$ 113,829
AESO deferral accounts payable *(note 7)*	**11,651**	17,123
MSA deferral account payable	**–**	177
Security deposits *(note 12)*	**1,689**	7,438
Bank debt *(note 8)*	**42,600**	30,100
	364,368	168,667
Deferred rent	**1,520**	1,465
Equity *(note 1)*	**–**	–
	$ 365,888	$ 170,132

Asset retirement commitment *(note 10)*

Contingencies and commitments *(note 11)*

On behalf of the AESO Board:

Harry Hobbs
AESO Board Chair

William D. Burch, FCA
AESO Board Member

Statement of Operations

For the Year Ended December 31 (in thousands of Canadian dollars)	**2006**	2005
Revenue		
Transmission tariff	**$ 946,303**	$ 845,610
Energy market charge	**12,712**	12,641
Load settlement charge	**4,820**	2,742
Interest and other	**1,413**	1,152
	965,248	862,145
Operating costs and expenses		
Wire costs	**444,931**	420,028
Ancillary services costs *(note 9)*	**235,175**	189,741
Line losses	**231,927**	200,789
General and administrative	**39,947**	38,632
Amortization *(note 5)*	**9,234**	6,631
Other industry costs	**3,585**	5,344
Interest expense *(note 8)*	**449**	980
	965,248	862,145
Net income	**$ –**	$ –

Statement of Cash Flows

For the Year Ended December 31 (in thousands of Canadian dollars)	**2006**	2005
Operating activities		
Net income	**$ –**	$ –
Amortization	**9,234**	6,631
Changes in non-cash working capital*	**105,008**	25,014
Net cash provided by operating activities	**114,242**	31,645
Investing activities		
Capital asset additions	**(24,419)**	(12,951)
Net cash used in investing activities	**(24,419)**	(12,951)
Financing activities		
Increase in bank debt	**12,500**	16,900
Increase in deferred rent	**55**	239
Decrease in AESO deferral accounts	**(5,472)**	(19,561)
Decrease in MSA deferral account	**(193)**	(4)
Net cash provided by (used in) financing activities	**6,890**	(2,426)
Increase in cash	**96,713**	16,268
Cash, beginning of year	**30,938**	14,670
Cash, end of year	**$ 127,651**	$ 30,938
Cash interest paid	**$ 828**	$ 1,035

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

Notes to the Financial Statements

December 31, 2006 and 2005
(All amounts are in thousands of Canadian dollars unless otherwise indicated)

Note 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.

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 Alberta Energy and Utilities Board (EUB or 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.

Note 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. 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 differs from the funding payments made to the MSA, the excess or shortfall is recorded in the MSA deferral account and incorporated into the estimated per megawatt hour charge for the following year.

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

Software development	5 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 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 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.

Forward Contracts, Operating Reserves – The AESO uses ancillary services forward contracts solely to ensure an adequate supply of operating reserves is available as required by the Alberta Interconnected Electric System (AIES). The AESO does not enter into contracts on a speculative basis. Any gain or loss on these transactions is applied to the cost of the products purchased when the physical operating reserves are provided.

Note 3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

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

As of December 31,	**2006**	2005
Regulatory asset		
Regulatory hearing costs	**$ 91**	$ 72
Regulatory liabilities		
Transmission deferral	**$ 4,278**	$ 11,322

During 2006, $0.1 million was incurred in legal fees related to the AESO's Needs Application for the Edmonton-Calgary 500-kV Electric Transmission Facilities Review and Variance 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, generally accepted accounting principles 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, 2006.

At December 31, 2006, the transmission deferral liability was $4.3 million based upon an accumulation of variances between transmission revenue collections and costs incurred from 2006 and prior years. On an annual basis, 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, generally accepted accounting principles would require that such balances be included in operating results in the year in which they are incurred. The regulatory liability is included in AESO deferral accounts payable on the balance sheet at December 31, 2006.

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.

Note 4. ACCOUNTS RECEIVABLE

	2006	2005
Transmission settlement	**$ 181,154**	$ 101,373
Energy market settlement	**2,734**	1,404
Trade	**7,874**	5,606
	$ 191,762	$ 108,383

Note 5. CAPITAL ASSETS

	Cost	**Accumulated Amortization**	**2006 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**
	$ 76,624	**$ 32,654**	**$ 43,970**

	Cost	Accumulated Amortization	2005 Net Book Value
Software development	$ 18,192	$ 3,590	$ 14,602
Energy trading system	11,410	8,215	3,195
System coordination computer systems	11,406	9,406	2,000
Computer hardware, furniture and office equipment	5,800	2,744	3,056
Leasehold improvements	2,753	647	2,106
Work in progress	3,826	–	3,826
	$ 53,387	$ 24,602	$ 28,785

Work in progress in 2006 relates to capital acquisitions associated with software development projects. In 2005, the work in progress related to software development costs and the construction of the system coordination facility which was completed in 2006.

For the 12 months ended December 31, 2006, interest costs of $0.4 million were capitalized during the construction phase of the system coordination facility (2005 – $0.03 million) and $1.1 million of payroll and payroll related costs associated with staff directly involved in software and hardware development have been capitalized (2005 – $1.4 million).

Note 6. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2006	2005
Transmission settlement	**$ 196,730**	$ 83,861
Energy market settlement	**89,230**	–
Trade	**16,186**	25,880
Accrued liabilities	**6,282**	4,088
	$ 308,428	$ 113,829

The accounts payable, trade balance includes flow-through customer contribution amounts of $11.1 million in 2006 and $20.1 million in 2005.

Note 7. AESO DEFERRAL ACCOUNTS PAYABLE

	Transmission	Energy Market	Load Settlement	Total
Opening balance, January 1, 2005	$ 30,075	$ 5,773	$ 836	$ 36,684
2005 Operations	(18,753)	269	(1,077)	(19,561)
Closing balance, December 31, 2005	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**

Note 8. CREDIT FACILITIES

The AESO has credit facilities of $110.0 million, comprised of a $50.0 million term revolving loan facility, a $40.0 million demand revolving loan facility and a $20.0 million demand non-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 $50.0 million term revolving loan facility is fully revolving for two year periods with a term to August 2007 and a provision for one extension. If the facility is not extended, the amount outstanding would be repayable in full in August 2007. Included in the $50.0 million term revolving loan facility is the option to request letters of credit.

In addition to the three 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 2006 and 2005.

At December 31, 2006, $1.0 million was drawn on and a $30.0 million letter of credit was issued on the term revolving loan facility, $21.6 million was drawn on the demand revolving loan facility, and $20.0 million was drawn on the demand non-revolving loan facility. The letter of credit was issued as security for operating reserve procurement.

The amount of interest paid during the year was $0.8 million (2005 – $1.0 million).

Note 9. ANCILLARY SERVICES COSTS

In April 2004, a contract between the AESO and a supplier of transmission must-run services expired prior to successful negotiations of a new contract. As a result, payments made by the AESO for services provided have been made in accordance with the AESO's interpretation of the transmission tariff and a letter agreement. The AESO and the service provider do not agree on the compensation and continue to work toward a resolution.

At year end, this issue remains unresolved and any settlement amounts related to the difference between the payments that have been made to the supplier and the final decision for a settlement amount for the period from May 1, 2004 to December 31, 2006 have not been incorporated into the transmission costs, as any difference is not determinable at this time. Amounts will be accounted for in the period they are determined.

Note 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.

Note 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)*
2007	2.0
2008	2.1
2009	1.8
2010	1.8
2011	1.9
Thereafter	6.8

(ii) To fulfill 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) The EUA requires the AESO to provide funding for the MSA with the amount to be recovered through the energy market charge. In 2006, $2.3 million was paid to the MSA (2005 – $2.7 million).

Note 12. 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.

Note 13. FINANCIAL INSTRUMENTS

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.

Note 14. COMPARATIVE FIGURES

Certain of the comparative figures have been reclassified to conform with the current year's presentation.

Design	S. Phillips & Associates Inc.
Project Management	Joan Moss
Editing	Karen Attwell
Photography	Horizon Photoworks, Justen Lacoursiere
Printing	CSM Media Inc.

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