Alberta Wholesale Market

A description of basic structural features undertaken as part of the 2012 State of the Market Report

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Market Surveillance Administrator | 403.705.3181 | #500, 400 – 5th Avenue S.W., Calgary AB T2P 0L6 | www.albertamsa.ca

PREFACE

The distinguishing feature of the Alberta market compared to most organized electricity markets is that it is 'energy-only', that is, the private sector bears the risk and decides on retirement of generation plant and investment in new capacity mainly driven by revenues derived or expected to be derived from the wholesale market. There is no regulated and centrally administered resource adequacy and planning mechanism. Apart from a price cap and price floor, prices in the spot market are regulated by the forces of competition, within the parameters of the Alberta market design and supporting rules and procedures. Finally, unlike most other organized electricity markets, participants are free to unilaterally engage in strategies to attempt to move the pool price (as long as they do not impede competitive responses) and there is no mechanism to administer prices or offers at some proxy of cost.

Under the circumstances outlined above it is obviously important that competition is doing its job in regulating market outcomes. The MSA can and does exercise its responsibilities to monitor market participant behaviour to ensure that it conforms to the standard set out in the *Electric Utilities Act* and amplified in the *Fair, Efficient and Open Competition Regulation*; however from time to time a more searching broad-based assessment needs to be made. This is the purpose of the MSA's State of the Market report.

As part of the work leading to the state of the market report the MSA is releasing a number of preliminary reports. This report focusses on describing the basic structural features present in the market and provides background information and context for the state of the market report.

The Market Surveillance Administrator is an independent enforcement agency that protects and promotes the fair, efficient and openly competitive operation of Alberta's wholesale electricity markets and its retail electricity and natural gas markets. The MSA also works to ensure that market participants comply with the Alberta Reliability Standards and the Independent System Operator's rules.

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Reader's Guide

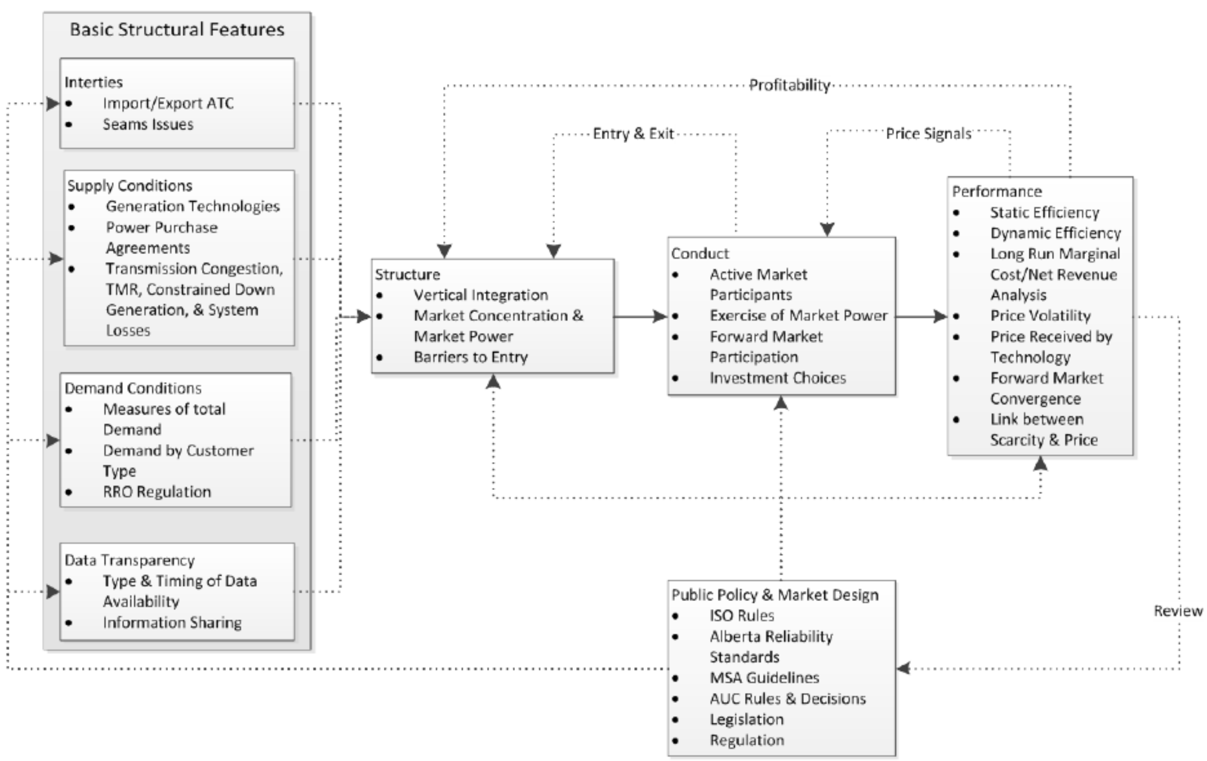
Purpose of the Report

The purpose of this report is to describe the basic or intrinsic structural features that are present in the Alberta market. The focus is on only those characteristics that the MSA views as relevant to an assessment of the state of competition within the Alberta wholesale market.

What is contained in the Report?

A graphical summary of the component pieces of the State of the Market Report is shown in Figure 1. This report addresses the basic structural features set out in the left hand box. The report is purely descriptive, providing what the MSA believes is necessary background to understand and analyze the Alberta wholesale market. As a consequence, there are no conclusions reached here as to the state of competition – these will be addressed in later work. Further details on the MSA's 2012 State of the Market Report can be found in our recently released paper, *State of the Market: Framework for Analysis.*

Figure 1: Alberta Wholesale Market



1. Introduction

The purpose of this report is to describe some of the basic structural features that help shape the landscape of the Alberta electricity market. This landscape is important in shaping the choices that market participants make and as a consequence the outcomes observed in the market. Many of the features that populate this landscape result from rules or regulations. Since the market commenced, a number of market reviews have occurred; while some changes have resulted, the basic structural features of the market remain mostly unchanged. Most other electricity markets over the same period have seen much more extensive intervention and re-design. The stability of the Alberta market design is in itself important in providing an opportunity for competition to flourish.

This report contains no conclusions but is meant to provide background information to assist the reader in understanding the MSA's State of the Market report. The MSA's State of the Market Report is expected to be completed in Q4 2012. Further details on this initiative are contained in the MSA's recent report entitled *State of the Market: Framework for Analysis*.

2. Market Design

Electricity markets feature a large number of rules and reliability standards typically administered through a central agency called an Independent System Operator (ISO). In Alberta, ISO functions are performed by the Alberta Electric System Operator (AESO). Many of the rules are primarily concerned with reliability, but some directly or indirectly relate to the organization of markets, also known as the 'market design'. Market rules themselves may be a function of legislation, but this is not always the case. The market design is a crucial component of understanding the space within which competition must develop. The design of the Alberta market is notably different from the designs utilized in most other electricity markets – these differences are discussed below. Significantly, Alberta's electricity market design has remained relatively stable since its inception, unlike most other electricity markets.

The essential features that define the Alberta wholesale electricity market are:[1]

- **Energy Only**: Many electricity markets feature separate payments for energy (electricity produced) and capacity (capability to produce electricity[2]). The Alberta electricity market has no payment for capacity, only for energy. Electricity generators make price and quantity offers in the energy market. The ISO sends 'dispatch' instructions to offered energy from lowest to highest price in order to match supply with demand. The system marginal price (SMP) is determined by the highest offer dispatched. The energy market is settled hourly at pool price, and the settlement interval coincides with clock hours (i.e. Hour ending 09 is from 08:00 to 09:00). The pool price is determined after the settlement interval ends as the time weighted average of System Marginal Price (SMP).
- **Operating Reserves:** In addition to receiving payments for supplying energy, generators can also provide operating reserves (although those providing active reserves may not offer into the energy market). Operating reserve acts as a safety net to help instantaneously balance supply and demand and to stabilize and protect the grid in the event of unforeseen problems.

[1] A more comprehensive description of the wholesale market can be found in an earlier report by the MSA published in 2010 entitled *Alberta Wholesale Electricity Market.*

[2] In many cases, 'capacity' includes electricity demand reductions that can be used to balance supply and demand.

Participation in the operating reserves market is voluntary and limited by technical requirements. Loads and the BC intertie compete with generation to provide some types of reserves. The ISO procures reserves through the market facilitated by Watt-ex, typically day-ahead.

- **Voluntary Forward market:** There is no ISO administered forward market, whereas some other electricity markets require participation in so-called 'binding' day-ahead markets to assist in scheduling production ahead of time. The Alberta market does feature forward transactions for energy on an exchange, via brokers or conducted as bilateral. In practice, buyers and sellers can choose forward transactions to limit their exposure to the hourly pool price.
- **No Legislated Reserve Margin:** Alberta relies on the expectation around future payments from energy and operating reserves to signal when new capacity is required. In Alberta, the ISO monitors current and future adequacy, but has very limited powers to act in the event of a potential shortfall. These do not include the ability to procure permanent generation. In contrast, many other electricity markets feature a legislated reserve margin (i.e. do not rely upon the market) for capacity.
- **No locational prices:** Many other electricity markets feature locational prices that signal geographical areas in which new capacity is needed. The Alberta market has a single price and a commitment to an uncongested transmission system. In the event congestion occurs, two things can happen: either additional payments are made as the result of requiring certain generators to run, or certain generators are prevented from running and the system marginal price is higher than it would otherwise have been.
- **Interconnections to other markets**: Alberta has interconnections with British Columbia, Saskatchewan, and soon, Montana. Imports and exports act as price takers; that is, all imports act as $0 generating offers and all exports act as $999.99 load bids. Unless conditions of surplus or shortfall are experienced, scheduled imports and exports flow regardless of the pool price.
- **No Offer Mitigation**: Generators are free to offer between the price floor of $0 and the price cap of $999.99. The MSA's *Offer Behavior Enforcement Guidelines* provide clarity on the MSA's view that participants are free to pursue a unilateral withholding strategy. Under no circumstances can participants pursue a coordinated strategy, nor can participants seek to impede competition. Other electricity markets, particularly those with capacity markets, often feature some kind of offer mitigation mechanism based on costs.

3. Supply Conditions

3.1 Generation Technologies[3]

Alberta's current generation capacity is dominated by coal and natural gas fired facilities.[4] At the end of 2011, these sources made up over 85% of the total capacity (see Figure 3.1). In recent years, net capacity additions have been dominated by natural gas fired facilities, and notable growth has also been observed in the level of wind generation.

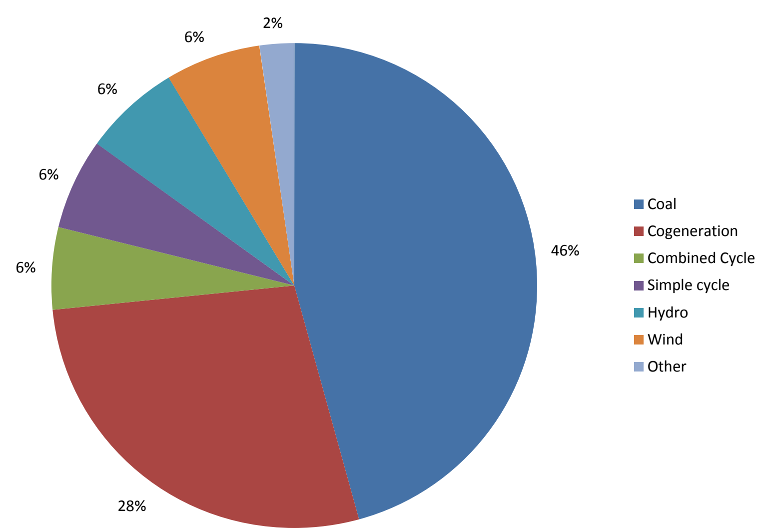
[3] Additional information on generation technologies, resources and generation outlook is contained in the AESO's 2012 Long-term Outlook

[4] Natural gas fired facilities include simple cycle, combined cycle and cogeneration facilities.

In terms of potential resources, Alberta has significant coal reserves, a developed network of natural gas pipelines and a number of areas attractive from a resource perspective to further wind generation. Hydroelectric potential also exists, particularly on the Peace, Athabasca, Slave, North and South Saskatchewan River Basins.

The development of resources and specific generation technologies is shaped by external forces and signals from the wholesale market.[5] In the Alberta market there is no legislated requirement for a given level of generation, no or reserve margin and no requirement for a particular resource mix. Currently external forces include the low natural gas prices which are seen to favour development of these gas-fired technologies. Uncertainty over climate change legislation and lack of support for renewables are cited as reasons that coal and wind generation are currently less favored. Signals from the wholesale market include the level and pattern (volatility) of prices. These may signal the need for new generation or for a specific generation type (for example: peaking vs. baseload capacity). More subtle market signals might cause market participants to develop portfolios, using a variety of generation sources to manage risk, or send no such signal and rely on forward transactions to manage risk.

Figure 3.1 : Installed Generation Capacity (December 31, 2011)



Source: AESO 2012 Long-Term Outlook. Note that this data is constituent with that posted on the AESO current supply and demand page which includes a mixture of capacity definitions (maximum capabilities, maximum continuous ratings and net to grid values depending on the asset).

3.2 Power Purchase Arrangements

In the late 1990's, the Government of Alberta recognized that the successful evolution of the wholesale market required mitigation of the market power held by the three large incumbent utilities, and the introduction of new market participants. Both these objectives were achieved with the development of the Power Purchase Arrangements (PPAs). Essentially all generation built under regulation prior to 1996 was covered by the PPAs. For the coal and natural gas units, the PPAs were considered physical arrangements as they transferred offer control of most of the capacity from the unit owner to the PPA buyer. This was a 'virtual divestiture' in that the original owners of the units still owned, operated them

[5] The MSA recently published a report on this topic, entitled *Investor Perspectives on the Attractiveness of Alberta's Electricity Generation Market.*

and to a large extent were kept in a similar situation as under regulation. For the hydro assets, all owned by TransAlta, the PPA was considered a financial PPA as offer control stayed with TransAlta.

The auction of the thermal PPAs listed in Table 3.1 was conducted in 2000. The PPA for H.R. Milner was not auctioned but terminated and the unit subsequently sold. Four PPAs (Clover Bar, Sheerness, Genesee and Sturgeon) were unsold at the time of the auction and three of these were transferred to the control of the Balancing Pool. Market Achievement Plans (MAPs) resulted in additional MW being sold for shorter durations. A number of changes have occurred since this time, including the resale of some PPAs, termination of the Clover Bar PPA in 2005 (and the subsequent retirement of the units) and the sale of the Sheerness PPA at the end of 2005. The Genesee PPA remains under the control of the Balancing Pool, although ownership has transferred from EPCOR to Capital Power Corporation. The duration of the PPAs was from January 1, 2001 to December 31, 2020 except where the assets were considered to have reached their retirement age before that. The PPA end dates are shown in Table 3.1.

Table 3.1: Thermal Power Purchase Arrangements

Plant	# of Units	Owner at time of auction	Fuel	Capacity (MW)	End of Effective Term	Date of Construction
Battle River	3	ATCO	Coal	663	2013/2020	1969-1981
Clover Bar	4	EPCOR	Gas	629	2010	1970
Genesee	2	EPCOR	Coal	762	2020	1989-1994
H.R. Milner	1	ATCO	Coal	144	2012	1972
Keephills	2	TransAlta	Coal	766	2020	1983
Rossdale	3	EPCOR	Gas	208	2003	1902
Rainbow	3	ATCO	Gas	93	2005	1999-2001
Sturgeon	2	ATCO	Gas	18	2005	1957-1961
Sheerness	2	ATCO/TransAlta	Coal	756	2020	1986
Sundance A	2	TransAlta	Coal	560	2017	1970-1973
Sundance B	2	TransAlta	Coal	706	2020	1976-1977
Sundance C	2	TransAlta	Coal	710	2020	1980
Wabamun	4	TransAlta	Coal	549	2003	1958-1968

The Power Purchase Arrangements still remain an important feature of the Alberta market, both as a constraint on asset control and in the impact that they have upon conduct. This seems likely to continue to be the case until 2020 when the return of the assets to the PPA owners will itself have implications for market dynamics. In this section we consider some of the important features of the thermal and hydro PPAs.

3.2.1 Thermal Power Purchase Arrangements

Some important details of the thermal PPAs are discussed below:

1. The terms of the PPAs include monthly payments that include payments for maintenance. However, it is up to the owner as to how to conduct the actual maintenance. The PPAs contain various provisions regarding planning of maintenance.
2. Owners are provided a financial incentive through Availability Incentive Payments (AIPs) to make the units available to the buyers. Payments flow to owners when unit availability is above target and to buyers when unit availability is below target. These payments are based on 30-day rolling average pool price and are split between on-peak and off-peak hours. As weekends are classed as off-peak within the PPAs, short-term maintenance is often carried out on weekends.
3. Operational control of the assets remains in the hands of the owners who also bear all the operational risks. Force majeure provisions apply to both the owners and the buyers.
4. Any capacity of the assets beyond the Committed Capacity (the capacity that is under the offer control of the buyer) belongs to the owner. Initially, this comprised small amounts of 'excess energy'. Over the years, many of the units have had uprates added. All this extra capacity is to the account of the owners. Typically, offers associated with this energy are transferred to the buyer who combines them with its own offers to submit to the pool (only one set of offers per asset is allowed at the pool).
5. At the end of the PPA, control reverts to the owner who can continue to operate the asset if they so wish. In some cases, PPA units will have considerable economic life remaining at the end of the PPA, although this is dependent in part upon the final form of federal coal regulations.[6]

3.2.2 Hydro Power Purchase Arrangement

When the form of the PPAs was being constructed, the Hydro PPA was recognized as being essentially different from the thermal PPAs due to the operational complexity of the hydro assets. Ultimately it was decided that the owner, TransAlta, would retain control of the 13 hydro assets and that there would be a financial obligation based on notional quantities of energy and operating reserves. These quantities are 'notional' in that TransAlta is free to choose how it actually operates the hydro assets. However, it is obliged to pay the Balancing Pool (the deemed PPA Buyer) the notional quantity times the relevant index price. Unlike the thermal PPAs, there are no force majeure provisions in the Hydro PPA.

At the time of the PPA auction, the market for operating reserves was not complete and hence the reserve obligations were simply expressed as a total volume. Subsequently, when the design of the operating reserves market was completed the Balancing Pool and TransAlta entered into a negotiation process that defined the reserve obligation for each hour among the three active reserve products: regulating, spinning and supplemental. The details of the obligation amounts by reserve product are confidential between the Balancing Pool and TransAlta.

3.3 Other Supply Constraints

The *Transmission Regulation* requires the AESO to plan and build a transmission system with little or no congestion such that all generators can compete to serve load. However, it is not always possible to always build transmission ahead of the needs and there are periods of time where congestion may occur. The AESO has a number of mechanisms to deal with congestion which inevitably impact generators (and loads) participation in the wholesale market. These include:

[6] For further details on the draft proposals made in 2010 see, Backgrounder: Key Elements of Proposed Approach.

- Transmission Must Run; and
- Constrained Down Generation.

In addition, any transmission experiences line losses (energy lost as energy is transferred from generators to consumers).

3.3.1 Transmission Must Run

Transmission Must Run (TMR) is a service provided by generators downstream of a transmission constraint in cases where there is otherwise insufficient in-merit generation available to meet the load. Much of the TMR service occurs under long-term contracts between the AESO and the relevant owners of the generators. In rarer cases the AESO can 'conscript' for unforeseen TMR from any out-of-merit generator in the system and the relevant tariff covers estimated operating and fixed costs, plus a return on investment. Table 3.2 shows the use of TMR and associated costs over the years. Since late 2007 a mechanism, Dispatch Down Service, has been used to offset the potential for TMR to have a price depressing impact.

Table 3.2: TMR Use and Costs[7]

Year	Estimated Number of Hours with TMR	TMR Volumes (GWh)	TMR Costs ($Mill.)
2005	8,724	861	56.4
2006	8,618	832	39.3
2007	8,699	893	47.0
2008	8,717	838	43.5
2009	8,745	753	26.4
2010	8,728	739	29.4
2011	8,729	744	26.2

Source: AESO

3.3.2 Constrained Down Generation

Constrained down generation (CDG) occurs when otherwise in-merit generation cannot serve load due to a transmission constraint (the opposite of TMR generation that can be thought of as constrained up generation). In the AESO's Transmission Constraints Management (TCM) rules, generation on the upstream side may be curtailed initially in reverse merit order, or pro-rata dispatch may occur if the constraint persists beyond two hours. In some cases, constraints are imposed by Remedial Action Schemes (RAS) or as generators approach RAS limits. In these cases, any MW constrained are not likely to be reflected in the recorded constrained down generation

[7] Note the figures in the table reflect updated numbers from the AESO and are not in all case the same as values previously published in the AESO 2011 Market Statistics and Annual Reports.

Table 3.3: Constrained Down Generation and Estimated Cost of Congestion

Year	Total (GWh) [A]+[B]	AESO estimates cost of congestion events ($Mill.)
2008	295	890
2009	55	100
2010	700	710
2011	142	n/a

Source: AESO 2011 Market Statistics, AESO 2012 Long-term Transmission Plan (Cost of congestion events are taken from Appendix K, Fig. 3 and are inclusive of TMR costs).

3.3.3 Transmission Line Losses

Transmission losses are the difference between the total generation entering the transmission system and the amount taken off the system to meet load. It is a measure of the transmission system's efficiency and losses will tend to grow as supply and demand grow in the absence of transmission investment. Losses are paid for by transmission connected generators, Industrial Systems Designations, Demand Opportunity Service customers, Importers and Exporters. There is some variation in loss factors dependent on location. Table 3.4 shows transmission loss factors between 2006 and 2011 with a general downward trend observable.

Table 3.4: Annual Transmission Line Loss Factors

Year	Transmission Loss Factors
2006	5.41 %
2007	5.20 %
2008	4.78 %
2009	4.55 %
2010	4.42 %
2011	4.56 %

Source: AESO: Current Loss Factors

4. Demand Conditions

Demand (sometimes referred to as 'load') conditions play an important role in shaping opportunities for investment and in influencing market outcomes. In this section we consider different measures of demand and provide a simple description of demand by customer segment.

Individual consumers have choice over how they purchases electricity and larger customers have additional options such as owning their own generation or reducing consumption in response to market prices. Residential, farm, irrigation and other customers with annual consumption less than 250 MWh can receive supply through the Regulated Rate Option. In aggregate, this represents a significant amount of overall load and the way this load is procured in the market is the subject of regulation. For this reason, it is worthy of special note.

4.1 Measures of Demand

Alberta Internal Load (AIL) is the most commonly used measure to gauge the demand of the province. AIL is defined as:

> a number in MW: (i) that represents, in an hour, system load plus load served by on-site generating units, including those within an industrial system and the City of Medicine Hat; and (ii) which the ISO, using SCADA data, calculates as the sum of the output of each generating unit in Alberta and the Fort Nelson area in British Columbia, plus import volumes and minus export volumes.[8]

Between 2000 and 2011, the AIL total energy demand experienced a 36% increase and the peak demand level rose by 31%. On an annual average basis, the AIL total energy demand and the peak demand grew 2.9% and 2.5% respectively. In 2011, the AIL total energy demand reached 73,600 GWh, the highest level since the inception of the market. The AIL peak demand set new records twice in January 2012, including on January 16, 2012 when the AIL peak demand reached the all-time high of 10,609 MW.

Not all AIL is satisfied by Alberta generation via the interconnected electricity market. For example, load served by on-site generating units, the demands of the City of Medicine Hat and Fort Nelson Area in British Columbia are not part of the Alberta Interconnected Electric System (AIES). Therefore, an indicator that is more relevant to gauge the in-province demand is AIES load.[9] The AIES load indicates how much of the AIL overall demand occurred within AIES and was served by the AESO-operated energy market.

An alternative measure of demand is the Firm Load Responsibility (FLR). This measure includes, in addition to the AIES load, the AIES losses and net firm exports.[10] FLR not only captures the in-province demand, but also the transmission losses and net exports that occurred in the AIES market place, which ultimately affect the pool price.

Unlike AIL, both AIES and FLR exclude the demand that does not participate in the energy market. Therefore, they are more relevant than AIL in assessing the investment opportunities other than the development of on-site generation. Much of this on-site generation has taken the form of co-generation. To the extent generation from these sources remains behind the fence, the demand profiles of AIES and FLR may also provide more useful insight of the potential impacts of demand on market outcomes.

Figures 4.1 and 4.2 depict the growth of energy and peak demand for the three categories over more than 10 years. It is evident that most of the growth is within the so-called 'behind the fence' load that is primarily served by on-site generation.

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[8] AESO *Consolidated Authoritative Document Glossary*, p3.

[9] AESO *Consolidated Authoritative Document Glossary*, p3. The AIES is published in AESO Market and System Reporting: Historical Report - *Uplift Charge Summary* (See AESO discussion paper *Presentation of Market metrics and Information*, p10)

[10] AESO *Consolidated Authoritative Document Glossary*, p15.

Figure 4.1: Growth in Total Energy Demand

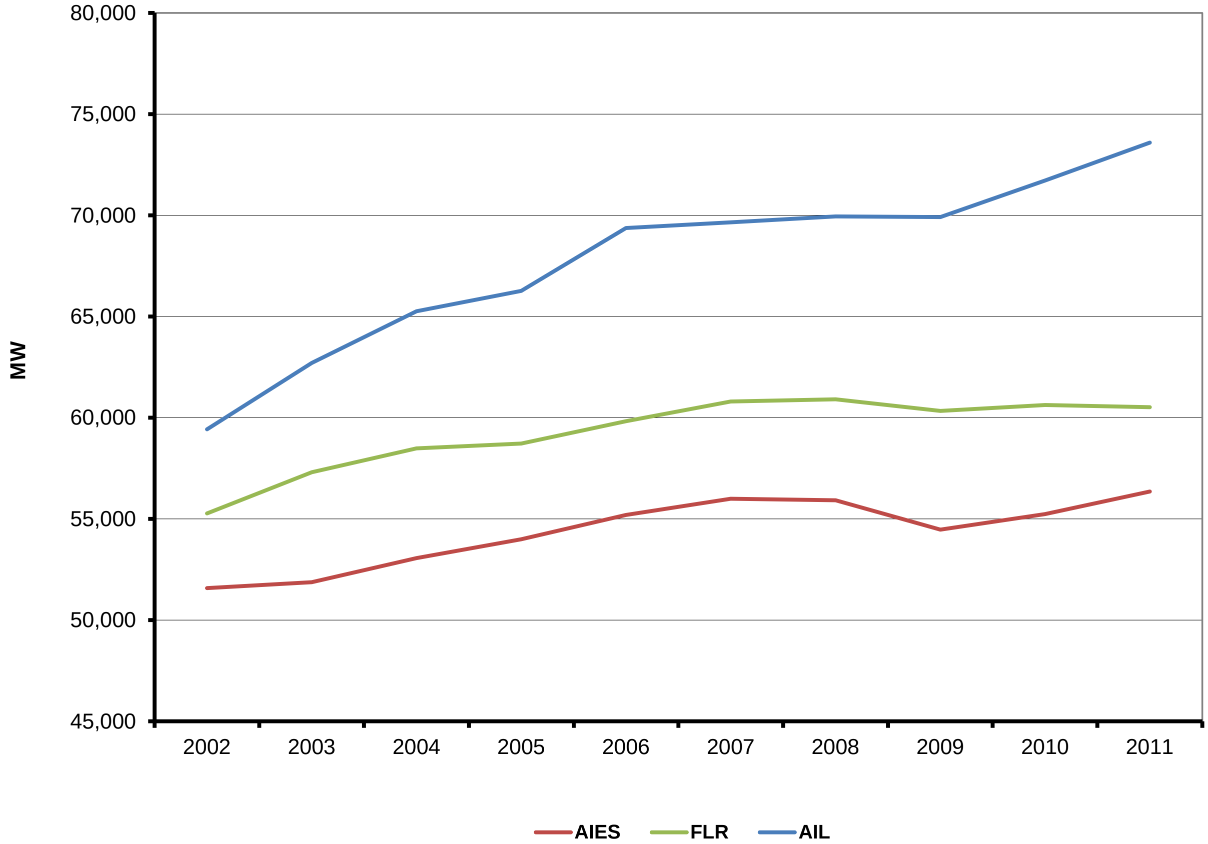
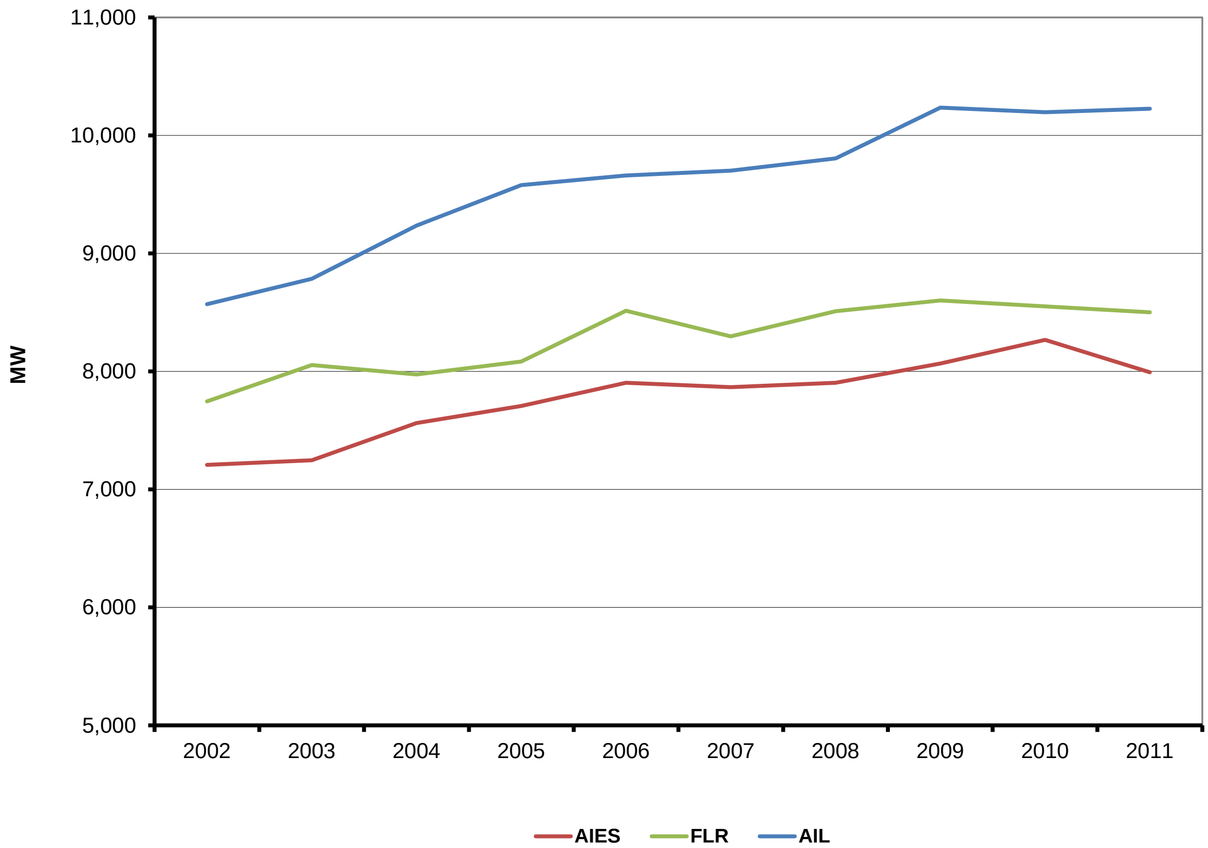


Figure 4.2: Growth in Peak Energy Demand

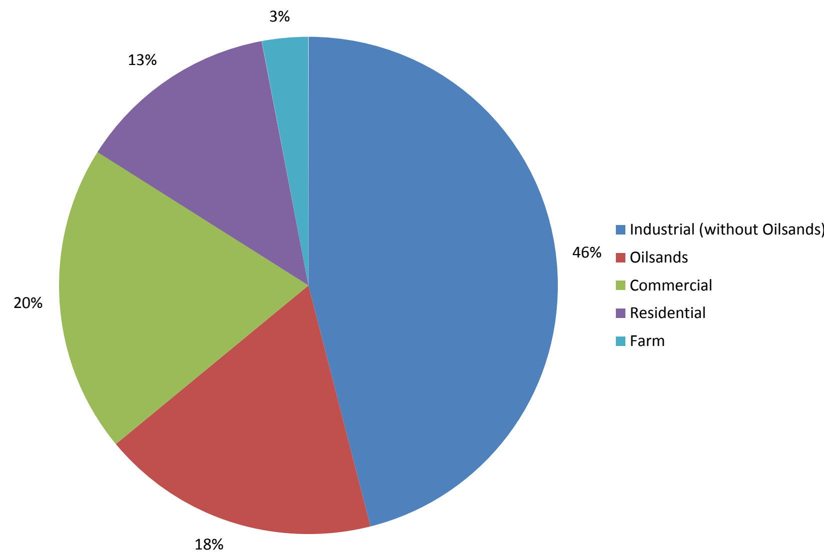


4.2 Demand Characteristics

Industrial demand makes up a majority of total Alberta electricity consumption and is expected to be the major driver in load growth over time. Residential and commercial demand is also expected to increase albeit at a much slower rate. Figure 4.3 shows the electricity consumption by sector in 2011.

High industrial demand translates to load factors (the percentage of average to peak electricity demand in a given period) that are relatively high compared to many other electric systems, since industrial consumption tends to be more consistent than residential or commercial consumption. Even so, the Alberta market features two significant increases in demand each day, in the morning and evening, followed by a decrease in the later evening hours. The difference in demand levels is reflected in commonly traded forward financial products that distinguish an extended on-peak period (between 7am and 11pm each day) and extended off peak periods (between 11pm and 7am the next day). The pattern and level of demand also varies by season.

Figure 4. 3: Customer Sector Electricity Consumption, 2011



Source: AESO 2012 Long-Term Outlook

4.3 RRO Regulation

All owners of an electric distribution system, or their designates, are required to provide a regulated rate tariff to eligible customers who have not selected a competitive retailer. The *Regulated Rate Option Regulation*[11] provides details on how that rate is to be constructed.

Each of the three main RRO providers (Direct Energy, ENMAX and EPCOR) must have an Energy Price Setting Plan (EPSP) approved by the Alberta Utilities Commission. They are termed Energy Price Setting Plans, as opposed to procurement plans, in that they allow for the possibility of self-provision by the providers. The EPSP plans have resulted from a negotiated process involving the providers, consumer groups and an independent advisor. The initial plans were in effect from mid-2006 through mid-2011. This included a transition period moving from longer term to shorter term hedges. Since mid-2010, the RRO energy price is based on energy priced a month ahead of delivery.[12] This allows for the RRO prices to be known before the energy is consumed.

Since mid-2011, the three main providers have been operating under new energy price setting plans which are essentially energy procurement plans. EPCOR moved to a plan involving several rounds of auctions in which it buys blocks of energy to match its RRO load forecast. Direct and ENMAX buy blocks of energy on the NGX trading platform. While the three energy price setting plans are quite different from each other, they have produced similar RRO energy prices.

The RRO load is significant as it includes all residential and small commercial/industrial customers (annual consumption less than 250 MWh) that have not selected a competitive retailer. The total annual RRO load of the three main providers is close to 10,000,000 MWh. The existence of the energy price setting plans ensures that a significant amount of trading occurs for one month out. This is the period when trading in the upcoming month would normally be expected to be very active, although only the

[11] *Regulated Rate Option Regulation,* AR262/2005 with amendments up to and including AR 264/2007.

[12] More specifically, the price setting period for a calendar month is the period beginning on the 45th day preceding the month and ending on the 5th business day preceding the month.

RRO loads are in a 'must trade' situation. Besides the main three providers discussed above, there are several municipalities and Rural Electrification Associations (REAs) that are responsible to provide a RRO to customers who have not selected a competitive retailer. Some have contracted with one of the bigger entities whilst some have developed their own.

In early 2012, the Alberta government struck the Retail Market Review Committee to look at various aspects of the RRO. The committee's report is due to be received by the government in September 2012.

5. Interties

Interties play an important role in the Alberta market. For in-province generators, the interties represent both a source of competition (via imports) and an opportunity to access other markets (via exports). The interties also allow some market participants to 'hedge' forward transactions. In this section we consider the size of the interties, in terms of both path ratings and available transfer capability, and the role of transmission rights and scheduling practices.

5.1 Intertie Path Ratings and Available Transfer Capability

Compared to many other electricity markets, Alberta's interconnections with its neighbours are relatively small in proportion to overall load. Alberta currently has two interconnections; to British Columbia[13] and to Saskatchewan. A third interconnection to Montana is currently under construction. The rated capacity of each is shown in Table 5.1.

Table 5.1: Interconnection Path Ratings

Interconnection	Import Rating (MW)	Export Rating (MW)
British Columbia	1200	1000
Saskatchewan	153	153
Montana (under construction)	325	300

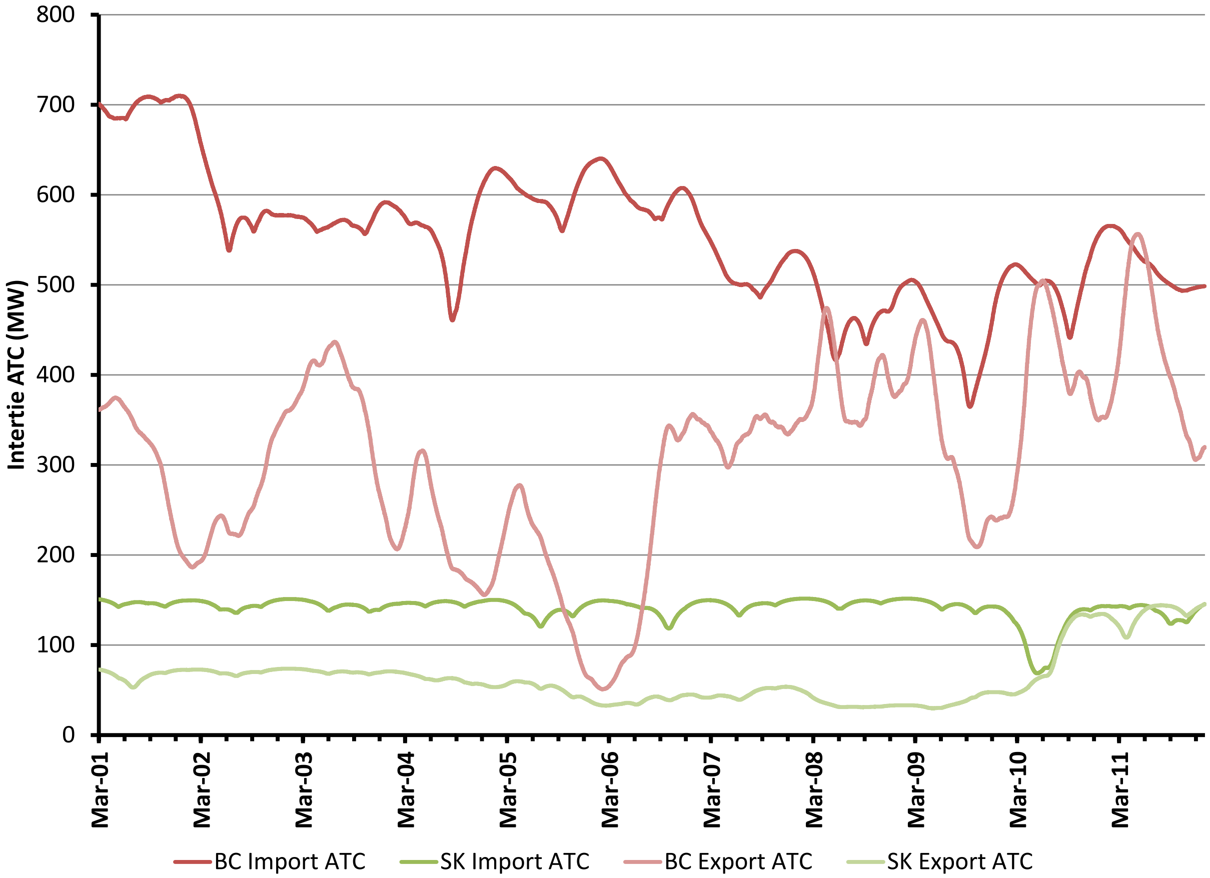
In practice, the available transfer capability (ATC) is much lower than the rated capacity. The intertie to Montana is not expected to increase total ATC due to interactions with the BC intertie. The *Transmission Regulation*[14] directs the ISO to restore interties that existed on August 12, 2004 to, or near to, their path ratings. The AESO has recently introduced a load shed service for import (LSSi) that adds to ATC in some circumstances and is considering other options for expanding both import and export ATC. Figure 5.2 shows the trend in ATC values since March 2001.[15]

[13] The Alberta-BC interconnection consists of one 500 kv circuit and two 138 kv circuits.

[14] '*Transmission Regulation*', AR 86/2007, 3(16).

[15] ATC is often quite volatile and consequently Figure 5.2 shows a smoothed ATC so the trend is more clearly visible.

Figure 5.2: Trend in Available Transfer Capability



5.2 Intertie Transmission Rights and Scheduling Practices

The Alberta market has no transmission rights, including the interties. Alberta's market design is such that imports and exports are opportunity services, meaning that they will be preferentially curtailed in certain situations. However, the entities on either side of Alberta (British Columbia and Saskatchewan) have transmission rights that are administered through their respective Open Access Same-time Information Systems (OASIS). On these OASIS sites, participants wishing to import or export energy buy access to the applicable transmission capacity. The rights have different levels of priority or 'firmness' and corresponding levels of prices.

To flow energy to or from Alberta, a participant needs a source of energy, a sink for the energy (one could be the Alberta power pool), and transmission access from source to sink. The participant must then create an electronic tag or 'e-tag' that describes all the above information and this e-tag is checked and approved by all the different control areas that will be affected. In addition, importers and exporters must comply with relevant ISO rules.

Whilst there are no markets in British Columbia and Saskatchewan, both can serve as conduits to access markets elsewhere. Through British Columbia market participants have access to Mid-C (an important and liquid bilateral market in Mid- Columbia) and other potential markets such as California. Through Saskatchewan there is potential access to the market administered by the Midwest ISO; however, in practice transmission constraints elsewhere and not on the Alberta-Saskatchewan intertie limit opportunities for flow in both directions. British Columbia and Saskatchewan both have wholly-owned affiliates who actively participate in the Alberta market.

6. Data Transparency

The timeliness and granularity of market information has a large influence on the behavior of market participants and, consequentially, on market outcomes. The AESO makes available a significant amount of market data, much of it close to real time.[16] In comparison to many other electricity markets, Alberta is at the high end of the scale in terms of providing market information. The general philosophy regarding market information is that more information enables participants to make more efficient decisions. The counter to that is at some point market information can, either directly or indirectly, have undesirable impacts on competition. Market data transparency has been the focus of some recent work by the MSA and features in a number of parts of the *Fair, Efficient and Open Competition Regulation*.

The Regulation includes a prohibition on the use of non-public outage information for the purposes of trading. Trading is only allowed after the AESO has made public aggregated information. While the PPAs had resulted in virtual divesture of offer control, outage information on PPA units is known both to owners and buyers. In addition a number of joint ventures resulted in outage information being known to more than one party. Figure 6.1 shows the estimated 'market shares' of information on unit outages for the largest 5 participants. The sum is more than 100% as MW of outage information is assigned to all parties involved with the unit.[17]

Table 6.1: Estimated Concentration of Market Visibility[18]

Participant	% of market visible
A	50%
B	23%
C	20%
D	18%
E	15%

The *Fair, Efficient and Open Competition Regulation* also features a prohibition on sharing offer information. In respect of this the Alberta Utilities Commission (AUC) has noted that:

> The sharing by two market participants of their non-public records has the potential to allow collusion and price-fixing by these participants, especially if the two participants have a substantial market share or market power. Such collusion can be harmful to the marketplace as a whole, especially consumers.[19]

The regulation allows sharing to occur if an information sharing agreement is approved by the AUC and in certain circumstances an exemption to this requirement applies. Recent work by the MSA has

[16] *AESO Market Reports*

[17] For purposes of the table, wind capacity has been excluded both the numerator and the denominator.

[18] Based on capacity data from the AESO current supply and demand report from August 2012. The calculations assume market participants have visibility of outage information related to units that they control or in which they have an ownership interest.

[19] *AUC Decision 2010-383*, para 15.

examined whether information made available by the AESO might similarly have the potential to facilitate coordinated or collusive outcomes.

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The Market Surveillance Administrator is an independent enforcement agency that protects and promotes the fair, efficient and openly competitive operation of Alberta's wholesale electricity markets and its retail electricity and natural gas markets. The MSA also works to ensure that market participants comply with the Alberta Reliability Standards and the Independent System Operator's rules.

Market Surveillance Administrator | 403.705.3181 | #500, 400 – 5th Avenue S.W., Calgary AB T2P 0L6 | www.albertamsa.ca