Electricity Industry Restructuring: *The Alberta Experience*

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May 2001

Draft: not for circulation; please do not quote

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Abstract

This paper focuses on the particular version of electricity industry restructuring that has been implemented in Alberta – one of the first jurisdictions in North America to embark on the journey to a more market-based system. In evaluating the concept and merits of electricity industry restructuring, this is a particularly appropriate case to examine. The Alberta market has most of the essential elements, and problems, of electrical systems elsewhere but it is modest in size and somewhat isolated from many complicating factors which tend to confound analysis of larger more interconnected systems, such as California. As such it is an ideal test case for policy analysis. In addition, there are several aspects of the implementation process that have been chosen for Alberta that are unique.

The paper summarizes the electricity market in Alberta prior to restructuring and discusses the motivations for lessening the governmental controls on the industry. The core of the paper focuses on the particular process chosen to move the Province's electrical power system into an almost fully restructured environment. A few key issues are examined which appear to be critical determinants of the eventual success of the process in Alberta and which also shed light on restructuring initiatives in other jurisdictions.

Electricity industry restructuring: The Alberta Experience

1. Introduction

"Deregulation" and "restructuring" have become frequently used words in nearly everyone's vocabulary in the past several months. While many industries have gone through the process of transferring decision-making and price setting from the confines of regulatory offices to the private market place, in no industry has it attracted the public attention that has occurred in the electricity sector. The primary reason for this, of course, is that unlike in most previous situations, and contrary to expectations, in some electricity markets prices have risen dramatically after the introduction of restructuring.[1] The factors driving this negative turn of events have been many, ranging from the physical nature of electricity networks and the structure of the industry, to flawed implementation, poor timing and just plain bad luck. This paper focusses on the particular version of electricity industry restructuring that has been implemented in Alberta. In evaluating the concept and merits of electricity industry restructuring, this is a particularly appropriate case to examine. The Alberta market has most of the essential elements, and problems, of electrical systems elsewhere but it is modest in size and somewhat isolated from many complicating factors which tend to confound analysis of larger more interconnected systems, such as California. As such it is an ideal test case for policy analysis. In addition, there are several aspects of the implementation process that have been chosen for Alberta that are unique. These elements make for an interesting environment in which to analyze the general merits of restructuring and to focus on the key implementation issues.

The paper begins with a summary of the development and status of the electricity market in Alberta prior to restructuring. Following this is an account of the motivations and drivers for restructuring and the initial steps taken to modify the regulatory control on the industry. The core of the paper focuses on the particular process, chosen in recent

[1] Although the two terms, deregulation and restructuring, are oftentimes used interchangeably, restructuring is more descriptive of what is happening in electricity markets today. Electricity markets continue to be regulated and government intervention continues to figure prominently in these markets. What is happening

months, to move the Province's electrical power system into an almost fully restructured (competitive?) environment. A few key issues are discussed which appear to be critical determinants of the eventual success of the process in Alberta and which also shed light on restructuring initiatives in other jurisdictions.

2. The Background Setting: Alberta's Electricity Industry

Alberta is somewhat unique in Canada in that there has never existed a single, vertically integrated Crown monopoly serving the electricity needs of the Province. In fact, the industry structure in Alberta more closely resembles the U.S. model with several vertically integrated firms operating as franchise monopolies, under cost of service regulation, with an integrated transmission network. Interestingly, and this could be construed as a "Canadian" element of the industry, there has been for some time a relatively high degree of coordination at the provincial level. Beginning in the late 1970's, the three major provincial utilities began dispatching their generation capacity as a single integrated system and were regulated as such by Provincial regulatory agencies. Generators continued to operate under a cost of service framework. In 1982, reacting to widening differences in generation and transmission costs between franchise areas, the Provincial government enacted the *Electric Energy Marketing Act* (EEMA). Under this act, a provincial agency purchased energy from the "generators", at cost-sensitive prices (basically in a cost of service framework), and resold this energy to "retailers" throughout the Province at a uniform price. Any remaining price differences between franchise areas were thus limited to differences in the distribution costs, which remained regulated.

Restructuring of the electricity industry was first broached in Alberta in the early 1990's. At this time, the Alberta electricity industry had, at its core, three vertically integrated utilities, which accounted for approximately 90% of the province's total generation capacity of about 8600 megawatts (MW). Two of these utilities were (and remain) investor-owned: Alberta Power (part of the ATCO group of companies and hereafter ATCO) and TransAlta Utilities (hereafter, TransAlta). The third major supplier, Edmonton Power (hereafter, EPCOR), was (and remains) owned by the City of

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is a change in the market rules: thus, our preference for the word "restructuring" and the use of this term in the remainder of the text.

Edmonton. TransAlta was by far the biggest player, accounting for over 50% of provincial generation capacity. It also supplied the municipal distribution utilities of Calgary and a number of smaller municipalities as well as its own franchise area. ATCO owned slightly less than 20% of total Provincial generation capacity, and EPCOR slightly more than 20%. All three were franchise monopolies, regulated by Alberta's Energy and Utilities Board (EUB) (the Province's energy regulator).[2] A small municipal utility (owned by the City of Medicine Hat), non-utility generators, and other small power producers provided the remaining 10% of generation capacity.

All in all, the three regulated utilities owned approximately 50 generating units, with about 75% of this capacity being coal-based. The remainder was about evenly split between natural gas-fired units and hydro. This fuel mix remains an accurate description of utility-owned generation today, since the major players (or anyone else, for that matter) have yet to make significant additions to capacity since the onset of restructuring in January 1996. Table 1 shows the merit order of supply in the Province immediately prior to restructuring. Because the utility owned generation capacity was centrally dispatched starting in the late 1970's, the merit order of supply was obviously public knowledge. This information, as well as the history of operation of the Province's utility generation units, meant that the introduction of a competitive bidding process in the wholesale market as "relatively" easy and the level of knowledge in information available in the market was relatively high.

Note that Table 1 does not include any cost information. Under the cost of service framework that existed, units were dispatched in order to meet the load, and tariffs were set in order to attain the regulated rate of return. So, the units were dispatched "efficiently", according to underlying economic data, but not as a result of a bidding process.

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[2] The utilities were regulated under a traditional cost of service framework, with prices set to achieve a regulated rate of return.

Table 1: Merit Order of Supply in Alberta Prior to Restructuring

Plant	Fuel Type	Capacity (MW)	Retirement Date	Owner
Genesee 1	Coal	385.6	2020	Epcor
Genesee 2	Coal	385.6	2020	Epcor
Keephills 2	Coal	382.6	2020	TransAlta
Keephills 1	Coal	382.6	2020	TransAlta
Sundance 6	Coal	365.7	2020	TransAlta
Sundance 5	Coal	354.6	2020	TransAlta
Wabamun 4	Coal	279.7	2003	TransAlta
Sundance 1	Coal	279.7	2017	TransAlta
Sundance 2	Coal	279.7	2017	TransAlta
Sundance 3	Coal	354.6	2020	TransAlta
Sundance 4	Coal	354.6	2020	TransAlta
Wabamun 3	Coal	139.9	2003	TransAlta
Wabamun 1	Coal	64.0	2003	TransAlta
Wabamun 2	Coal	64.0	2003	TransAlta
Sheerness 1	Coal	379.6	2020	ATCO
Battle River 5	Coal	369.6	2020	ATCO
Sheerness 2	Coal	379.6	2020	ATCO
Battle River 4	Coal	147.8	2013	ATCO
Battle River 3	Coal	147.8	2013	ATCO
Milner coal	Coal	109.5	2012	ATCO
Milner gas	Gas	35.4	2012	ATCO
City of Medicine Hat	Gas	50.0	-	
BC Hydro	(import)	400.0	-	
CloverBar 4	Gas	157.9	2010	Epcor
CloverBar 3	Gas	157.9	2010	Epcor
CloverBar 2	Gas	157.9	2010	Epcor
CloverBar 1	Gas	157.9	2010	Epcor
Rossdale 10	Gas	71.1	2003	Epcor
Rossdale 9	Gas	71.1	2003	Epcor
Rossdale 8	Gas	67.0	2003	Epcor
Rainbow 2	Gas	40.0	2005	ATCO
Rainbow 3	Gas	21.5	2005	ATCO
Rainbow 1	Gas	26.0	2005	ATCO
Sask. Power	(import)	150.0	-	
Sturgeon 1	Gas	10.0	2010	ATCO
Sturgeon 2	Gas	8.0	2010	ATCO

Finally, it is important to emphasize the extent to which Alberta was and remains an "electricity island". The interconnections with British Columbia through the BC Hydro system to the west, and with Saskatchewan through Sask Power's grid to the east are relatively small compared to the total capacity and load in Alberta. By the end of 1995, these two lines provided Alberta with access to about 550 MW, roughly equal to 6% of the province's total generation capacity.[3] There still does not exist a direct interconnection between Alberta's electricity grid and any U.S. system.

3. The Initial Period of Restructuring: 1996 to 2000

The *Electric Utilities Act* of 1995[4] was the first formal step in the process of restructuring of the electric power industry in Alberta. Among other changes to the industry, the Act established a *Power Pool* through which all electricity in the province would flow. Bids to supply power into the Pool and to purchase power from the Pool would determine, on an hourly basis, the wholesale market price of electricity. The underlying intent of the legislation, as with all restructuring initiatives, was to allow a competitive market to begin providing the price signals that would lead to increased market efficiencies. In particular, by deregulating decisions about new generation, the new structure shifted questions relating to the type, timing, and amount of generation additions from regulatory hearings to the market.

The above approach was essentially quite similar to most restructuring initiatives. Alberta's electricity system was somewhat unique however in one important aspect, namely the average cost of embedded generation. Alberta's system was very low cost and, unlike many jurisdictions, new generation units were (and still are) expected to have average costs above the embedded system cost.[5] In this low average cost system, one major issue to be addressed is the impact of restructuring, and more specifically the impact of marginal cost pricing in the wholesale market, on prices. Specifically, the possibility of important rent transfers from consumers to low-cost generators was

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[3] The 550 MW was made up of 150 MW to Saskatchewan to the east and 400 MW to British Columbia to the west. The British Columbia link is now 800 MW.
[4] This act of the Provincial parliament came into effect in January of 1996.
[5] Note that high cost was not a driver of restructuring in Alberta. Two important drivers were the desire to streamline the regulatory process and to move to market based decisions where possible.

immediately recognized. This issue was dealt with in two successive steps in Alberta that will be discussed in this paper, namely the implementation of legislated hedges in the wholesale market and later on the auction of the energy produced from regulated generation capacity.

The *legislated hedges* introduced in the Act in effect tied the generation price of electric energy between January 1996 and December 2000 to the cost of service of regulated units. Owners of these regulated units (i.e. utility built before 1995) therefore were unaffected by the price level of the Power Pool. Retail demand served by these units likewise was unaffected by the price level of the Power Pool.[6] The hedges were designed with two separate, but closely related, objectives in mind. These were to mitigate the exercise of market power by the three large utilities and to protect existing retail customers and regulated generation units from the pool price.

With respect to the first objective, even though the generation market remained highly concentrated and a bidding process determined the wholesale price of electricity, the three regulated utilities had no incentive to influence prices because of the hedges. This was an effective response to the market power issue, at least in the short term. For most of the 1995-2000 period wholesale prices did remain very low.

With respect to the second objective, existing regulated units and retail demand were insulated from the changes in the Pool price, while new supply and demand were meant to see the appropriate price signal of the new Pool price. Existing generation units (also referred to as regulated units) were built under the assumption that they would recover their costs, including a regulated rate of return, over their useful life. Since the Pool price was (correctly) expected to be low on average in the early years and to rise over time as demand rose relative to supply, without the legislated hedges, the relatively new plants would have high "stranded fixed costs" and the older, depreciated plants would have received a "windfall" gain. This hedge was calculated so as to give both old and new units a return similar to that expected under the former regulatory regime. Only existing

[6] But, the Pool price was the price seen by new merchant capacity built after 1995 and new retail demand.

non-utility generation, new generation (since it was deregulated, all new generation would be "non-utility"), and generation quantities above or below rated output faced exposure to the Pool price. On the demand side, retailers (again primarily the vertically integrated big three, plus the municipal utilities of Calgary, Red Deer, and Lethbridge) were on the buying side of the legislated hedges, which protected them from volatility in the Pool price by giving them a hedged price equal to the average cost of existing utility generation.

As a result - and by design -consumers noticed little change from the days of old-style regulation. In fact, the market changed very little with the transition to the pool mechanism in 1996, mostly because a healthy capacity margin kept pool prices low. As will be discussed later in the text, these low prices, though welcomed by consumers, likely had a detrimental long-term effect on the market in that they were partially responsible for delaying entry in generation. This, it would appear today, is a significant effect of the legislated hedges. Between 1995 and 2000 the market tightened unexpectedly quickly because of higher-than-forecast growth, both in the Alberta economy and in electricity demand. During this period entry in the generation segment of the industry was limited to natural gas-fired cogeneration plants tied to large industrial projects. As in other jurisdictions in North America, natural gas was considered to be the fuel of choice for new electricity generation (because of improvements in natural gas generation technologies, relatively low natural gas prices and relatively short construction lead times, among other reasons).

Interestingly, although the regulatory framework allowed it, no merchant generation plants were built during this period, and this even though the supply cushion was tightening. One explanation that has already been given for this is the low Pool price. During 1995-2000, because of the legislated hedges, prices stayed below the level necessary to justify new plant construction, and this despite the tightening supply cushion.[7] Of course one might have expected to see some interest in construction of new capacity, in anticipation of the removal of the legislated hedges and in the face of

[7] Recall that in Alberta, the long-run marginal cost (i.e. new plants) was greater than the long-run average cost, and legislated hedges kept Pool prices at the average cost.

continued demand increases. However, it is now recognized that too much policy uncertainty regarding the resolution of the restructuring initiative existed during this period. Among other things, the uncertainty relating to the continuing monopoly position of distributors over retail customers in their respective franchise area (with the exception of self-generating industrial customers) was a major concern. Since this monopoly position was viewed as temporary, pending the next stage of restructuring, and because the terms of retail competition were not clearly established, there was no one in a position to contract for load growth for that market. Indeed, the only demand to appear as a large identifiable block in the market was industrial load under self-generation that, as has been pointed out, turned to natural gas generation on a project-by-project basis. Potential new generation was thus not able to hedge itself in the retail market, making entry much more risky. Not surprisingly, as will be seen shortly, EPCOR (city of Edmonton integrated utility) and ENMAX (city of Calgary distibutor and retailer), today's two dominant retailers, were very active in acquiring capacity in the auctions of the regulated energy.

In an effort to create proper price incentives for both supply and demand and to proceed further along the restructuring path, an *Amendment to the Electric Utilities Act* was passed in 1998. The new legislation called for the removal of the legislated hedges (in January of 2001) and for the introduction of new measures to enhance competition among both suppliers and retailers of electricity. For the first time, both the supply and demand sides of the market would be exposed to the market incentives provided by the Power Pool prices. The primary issues now facing policy makers centered on the means to move towards a competitive market and the speed at which to make this move. There were several key decisions, but the most difficult were on the supply side. At one extreme, a slow path could be chosen which left existing supply in the hands of the current owners but limited the incumbents' participation in new ownership so that over time more widespread competition would emerge. At the other extreme, immediate divestiture by the big three utilities of a large portion of their existing generation capacity could be mandated. Balancing a desire to move rapidly on the restructuring course against a political philosophy that respected private ownership, the government chose an innovative intermediate path.

The chosen plan called for the ownership and operation of existing utility generation units to be left in the hands of existing owners (i.e. no forced divestiture) and for new supply to continue to be totally unregulated. The controversial and somewhat unique new element of the plan obliged the owners of the regulated generation units to sell the ownership rights to the energy from the remaining life of these plants at a one-time auction. These ownership rights were referred to as Power Purchase Agreements (PPAs). The purchasers of these PPAs, possibly but not necessarily new players in the market, would then be responsible for bidding the energy into the Alberta Power Pool on a daily basis. In this sense, the auction, with strict limits on purchases, would reduce market concentration of regulated units, thereby, it was hoped, increasing competition in the wholesale market and leading to lower electricity prices. Because this new wholesale market would be open to anyone with demonstrated financial security, the plan was that a sizeable collection of new participants would be attracted into the supply side market and create a new level of competition. The second goal of the sale of regulated energy was to capture the "stranded benefits" associated with the low cost embedded generation. The Province basically sought to retain the increase in value of these plants (over and above the regulated return) that would be created by wholesale prices moving much higher than what was required under the cost of service framework. The auction of these Power Purchase Agreements was clearly the most adventuresome aspect of the Alberta restructuring process.

Alberta's existing utility generation plants, as listed in Table 1, were grouped into twelve PPAs, (see Table 2 for a list of the PPAs), for sale.[8] The terms of each PPA contract called for the buyer to pay the owner/operator of the generators (who were, in each case, one of the big three utilities, TransAlta, ATCO, and EPCOR) the marginal generation (primarily fuel) cost of each unit of power produced and sold into the Power Pool plus a fixed monthly payment representing the annualized, unrecovered capital cost of the plants (Capacity Payments). The details of these payments were predetermined by regulatory officials and indexed to fuel costs and various economic variables. The buyers of the PPA contracts obtained the right to bid, on a daily basis, the power from the plants into the

[8] Note that the regulated hydro plants were not included in the auction. The operational control of hydro is to be maintained by an arm of the Power Pool.

Alberta Power Pool and to retain the revenues. The contracts also contained incentive mechanisms to encourage plant operators to strive for operational efficiency and maximum availability of their generation capacity. For instance, energy in excess of the contractual obligation to the PPA owner would belong to the owner of the plant and be available to be bid into the Pool.

These PPA contracts were sold in a large public auction that took place during the first two weeks of August 2000. The Province of Alberta auctioned these contracts and retained the net proceeds of the auction. The rationale for this, as was mentioned above, was that the contracts provided the owners of the plants with a regulated rate of return via the payments from the PPA owners, as under the old regulatory framework. The excess value of the regulated plants, the “stranded benefits”, was then returned to the Province as net proceeds from the auction.

Most of the PPAs for existing plants had lower fixed charges and were expected to sell at high prices reflecting a differential between expected future Pool Prices and their low marginal energy costs. Some newer plants on the other hand had high fixed capacity charges attached to them and the associated PPAs were expected to be sold at negative prices in the auction – meaning that the PPA owner would be paid by the Province to become the owner of the regulated energy associated with the plant. Overall, the expectation was that the sum of winning bids in the auction would be substantial and would approximate the present value of the difference between the expected Pool Price and the total costs of generation embedded in the PPAs. This surplus - to be accumulated in a "Balancing Pool" (a fund associated with the Power Pool) – would then be returned in some form to consumers as compensation for having to buy electricity from retailers whose prices, based on the Power Pool, were expected to reflect the (higher) cost of new generation, rather than the (relatively low) average embedded cost of existing generation (about $30 per megawatt-hour in 1998). In other words, this surplus was meant to reflect the “value” to Alberta consumers of the embedded regulated generation and the intent was to return these rents to them in a manner that did not compromise market efficiency.

Because the PPA acution process had two distinct objectives, namely to introduce structural relief in the generation/energy supply segment in order to foster a competitive environment and to capture the standard assets in existing regulated generation, the eventual success of the auction was highly dependent on the amount of competition that the auction would create. The more competition in the auction, the more potential players there would be and the greater the value obtained by the Province (stranded benefits). Unfortunately, the number of firms that registered for the auction was almost identical to the number of PPAs that were for sale. Most of these firms did place deposits that would have allowed them to bid on more than one of these contracts[9]. In terms of the number of bidders, this was probably close to the minimum that the Government would have accepted without withdrawing the auction (though Government criteria on this was never made public). While somewhat below early estimates, and certainly disappointing, these values gave hope that there would be 'reasonable' competition in both the auction and the subsequent wholesale market.

The format of the auction was a series of ascending price-bidding rounds - with four to six rounds per day - conducted over a three-week period. Bidding was simultaneously open on all PPAs in each round and was conducted using a secure internet site. The rules of the auction were such that a firm had to keep actively bidding in order to retain its initial eligibility (as determined by its deposit). For example, if a firm had placed a deposit so as to have the right to bid on 800 MW of power, it had to place active bids in each round for this much capacity. (The rules allowed some latitude in this regard, particularly in the early rounds – the specifics are detailed in [4]). Early on in the auction however, most firms let their eligibility drop to a level such that the amount of power being sold was only slightly exceeded by the number of eligible bidding units. As a result, the competition for each PPA was far from fierce. A total of eight PPAs were sold to 5 separate firms. Table 2 lists the PPAs along with the results of the auction.

[9] The 7 firms registered for the auction placed deposits, in total, which would have allowed them to bid on 10,000 MW of power. The total capacity of the PPAs being sold was just over 6,400 MW.

Table 2: Power Purchase Agreements Offered for Sale in August 2000

PPA	Capacity (MW)	Winning Bidder	Final Price (millions)
Battle River	**666**	**Epcor**	**$84.9**
Clover Bar	**631**	***not sold***	
Genesee	**762**	***not sold***	
Keephills	**762**	**Enmax**	**$240.7**
Rainbow	**93**	**Engage**	**($21.0)**
Rossdale	**208**	**Engage**	**$0.0**
Sheerness	**760**	***not sold***	
Sturgeon	**18**	***not sold***	
Sundance A	**560**	**TransCanada**	**$211.9**
Sundance B	**706**	**Enron**	**$294.8**
Sundance C	**710**	**Epcor**	**$268.5**
Wabamun	**549**	**Enmax**	**$75.1**
Total	**6425**		**$1,154.9**

The PPA contracts associated with the new plants with high fixed payments (which were expected to draw negative bids) did not sell nor did the gas-fired peaking plants. The prices commanded by the PPAs that did sell were low, reflecting either a lack of competition or conservative forecasts of future prices. Each of these possibilities will be examined.

The design of market mechanisms, particularly for markets with small (2-20) numbers of participants, has been the focus of a considerable amount of research over the past two decades (see [5]). In particular, the application of game theory to the analysis and design of auctions has produced a large number of important theoretical and empirical results (see [6] for a comprehensive survey of this work). In 1994, this research began to influence practice with the auction of radio spectrum rights in the U.S.A. by the Federal Communications Commission. Several prominent theorists were invited to propose designs for this multi-billion dollar auction of bandwidth for wireless communications. The FCC chose a design submitted by Paul Milgrom and Robert Wilson of Stanford University that involved an ascending-bid process whereby blocks of wireless rights across the nation were simultaneously auctioned. The auction generated over $7 billion in revenues for the FCC and was generally considered to be a success [7]. Subsequent analysis, however, has cast some doubt on the efficiency of the process and has suggested that informal collusion (particularly in the case of the 'B-Block' auction where the number of bidders was small relative to the number of blocks for sale) may have lead to sale prices well below competitive levels. To quote from [8], "*When multiple items are sold through the use of a simultaneous ascending-bid auction, bidders can find it in their mutual interests to reduce their aggregate demand for the items while prices are still low relative to the bidders' valuations. The FCC's first broadband PCS auction provides examples of how such mutual reductions might be "arranged" even when the bidders are not allowed to communicate with one another outside of the auction arena.*" Because the auction mechanism used to sell the electricity PPAs in Alberta was almost identical to that used for the spectrum rights in the U.S.A, similar concerns might be raised about the power auction. One notable change in procedure was to limit information on the identity of other bidders between rounds of the Alberta PPA auction. However, the number of participants was small enough that it is conceivable that implicit cooperation was possible ("…don't raise the bid on mine and I won't bid on yours".). This same lack of public information on the identity of the bidders also makes subsequent analysis of bidding behavior difficult.

Recent research also points to another potential problem with open ascending price auctions that may have been a factor in keeping prices low in the PPA auction. Since the early 1970's, considerable attention has been focused on the 'winner's curse' issue in common-value auctions. An auction is termed 'common-value' if the item being sold has the same economic value to all bidders. In most circumstances, this common value is uncertain – no bidder knows exactly what the item will eventually be worth should he or she succeed in acquiring it. A classic example is an oil lease. At the time of the auction, no one (including the auctioneer) knows the value of the oil beneath the ground but all bidders have estimates of that value and each knows that whatever the ultimate quantity discovered, the extracted value will be the same in each parties' hands. Early empirical research on off-shore oil leases in Louisiana indicated that, in such circumstances, the winning bidder was usually the one with most (overly) optimistic estimate (seismic survey) of the value of the lease and that subsequent revenues from drilling often failed to match the price paid at auction. The winner of the auction was 'cursed' with a loss on the transaction. Theory and practice over the intervening years has shed light on the correct level of discounting of estimated values so as to avoid the curse when bidding in a common value auction. The resulting shaded bids should, on average, produce a competitive level of profits for both the winning bidder and the auctioneer (as a function of the number of bidders – with the auctioneer gaining a larger share of the profits from the transaction as the number of bidders increases). In a recent paper however, Klemperer [9] has shown that even a mild asymmetry in the value that individual bidders obtain from the sale or use of the item being auctioned can have an 'explosive' (downward) effect on the expected revenue obtained by the auctioneer. If it is common knowledge among the potential bidders, that the assets being auctioned will be more valuable in one bidder's hands than when owned by any of the others, then the optimal bids for each party to place in the auction are only a fraction of what they would otherwise be. In other words, the privileged bidder can expect to face greatly reduced competition for the item being sold.

In the Alberta PPA auction, it was common knowledge among bidders (and most industry observers) that some firms, in particular the two large municipal utilities in Edmonton and Calgary, EPCOR and ENMAX, appeared to be positioned to obtain marginally greater value from the acquisition of wholesale power packages than other registered bidders. Both of these firms had an existing (though no longer guaranteed) customer base with its requisite attributes of customer loyalty and billing efficiencies. They were 'long' on the demand side of the new power market and the wholesale power parcels (PPAs) nicely complemented their portfolios. Most of the remaining bidders, in the short to medium term at least, faced the prospect of extensive exposure on the supply side if they were successful in obtaining PPAs. The theory predicts that in such a circumstance, these firms will lower their bids significantly even relative to their real competitive disadvantage.

In light of these observations, the results of the August 2000 PPA auctions will be examined. Each PPA contract is a complex instrument whose value is a function of numerous variables. Many of these variables are highly uncertain over the horizon (in some cases, 20 years) of the contract. The value of a PPA contract is the net of the present value of the stream of differences between the hourly Pool price for electricity in Alberta and the marginal cost of generation (primarily the fuel cost of gas or coal) minus the fixed monthly capacity payments as specified in the contracts. Table 3 illustrates some approximate calculations for one of the large coal PPAs. Shown are the internal rates of return for a variety of average Pool prices over the life of the contract given the actual auction sale price. Immediately obvious is the extreme sensitivity of the value of these contracts to future electricity prices. At prices that prevailed in the period prior to 1999 (less than $35/MWh), the contracts are only marginally profitable. At prices that have prevailed since the auction (over $70/MWh) they are extremely lucrative!

TABLE 3

Rates of Return Implied by Auction Sale Price for Various Pool Prices

Average Pool Price	Internal Rate of Return
$30/MWh	2%
$40/MWh	27%
$50/MWh	48%
$60/MWh	68%
$70/MWh	87%

***Assumptions**: "Sundance A" PPA with coal price of $4.50/MWh and indicated Pool prices (in 1999 $Cdn) over the 20 year life of the plant; auction sale price of $211.9 million and annual capacity charge of $86.5 million.*

With a Pool price of $76/MWh, the payback period for the purchase of such a PPA is just one year! As Figure 1 and Table 4 illustrate, the average Pool price has in fact been much higher since the August auction. Similar results are obtained for other PPA contracts. Based on this cursory analysis, the winning bids appear to have been quite low compared to the realized value of the contracts. Some possible explanations for the low prices bid in the auction are

(a) Bidders adopted very conservative forecasts of future Pool prices (well below the prices that have prevailed over the last year in Alberta),
(b) Bidders discounted future profits heavily in light of uncertainties over the long horizon of most of the contracts, or
(c) Less-than-competitive conditions prevailed in the auction for reasons such as those described previously in this section of the paper.

Figure 1 shows the monthly average Alberta Pool prices over the last several years. In light of the recent values, the revenue obtained from the auction is low. The Balancing Pool netted a total of just over $1 Billion from the auction, well short of initial expectations. If prices remain at the levels seen in recent months, this sum will be sufficient to subsidize consumers and shelter them from the high prices for less than a be year.

On the more important (in the long term at least) issue of increased competition on the supply side of the market, the number of firms bidding power into the Pool has now more than doubled to eight but the jury remains out as to whether this will be sufficient to support a competitive market. The key will likely be the rate and ownership pattern of new supply. A recent report issued by the Alberta Department of Energy paints an optimistic picture with a forecast of 2900 MW of new supply coming on line over the next 5 years. There is some evidence however, that the incentives for non-price-taking behavior remain high. In October of 2000, the Market Surveillance Administrator (MSA) of Alberta issued a report in response to the high prices of the summer. While enumerating several structural factors behind the prices, including high natural gas prices and the influence of shortages in California and rising demand (see Figure 2), the report also discussed ‘behavioral’ factors. Questions were raised about bidding and plant availability on the supply side. The MSA concluded that the potential for the exercise of market power was still a concern in Alberta but that data and evidence was lacking to draw any conclusions with respect to current prices. In light of similar behavior in the first years of restructuring in Britain [3 and 10], it would not be surprising if attempts to exercise market power occurred in Alberta as well.

Figure 1: Average Monthly Pool Prices

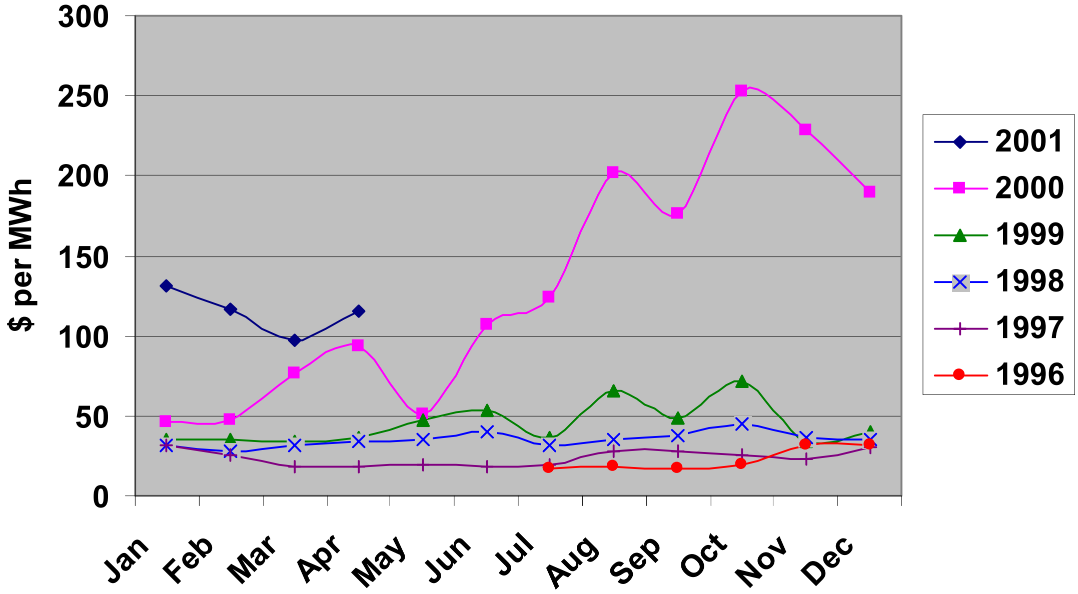
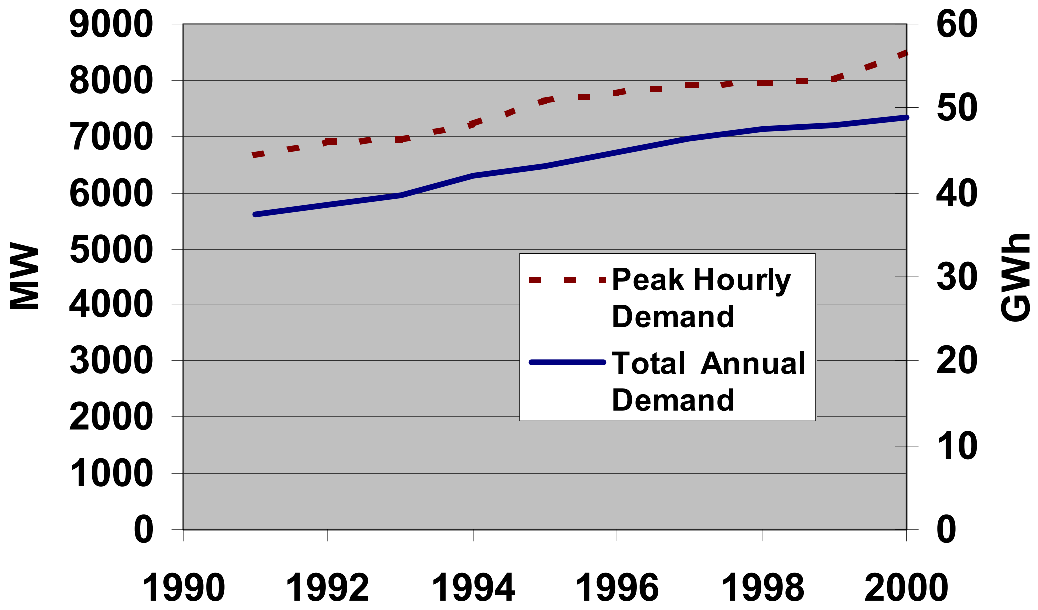


Figure 2: Demand Growth in Alberta



On the retail side of the market, initial plans were to move to open competition on January 1, 2001. All retail customers would have freedom of choice with respect to their supplier. Prices would be determined through negotiable contracts and were expected to range from spot market pricing to long-term arrangements. The retail market would be opened up to anyone who wanted to participate. To provide residential and small commercial customers with a period of grace to understand the new market and to adapt to the potential volatility of prices, a Stable Rate Option (SRO) was included in the legislation (the name has been changed to Regulated Rate Option (RRO)). These smaller consumers of electricity were given the option of continuing to buy power from their current franchise utility, under terms subject to regulatory oversight by the EUB, for up to five years. The existing utility was required to supply this contract, while their customers surveyed the new marketplace and sought retail contracts to suit their needs. The distribution network, however, was to remain a regulated segment of the industry, populated by the three regulated utilities and a few wire-owning municipalities. After January 2006, all retail franchise rights and obligations were to disappear from the Alberta electricity market.

In November of 2000, in the face of skyrocketing wholesale prices, the Government of the Province placed a hold on the plans for a deregulated retail market. Retail prices were capped for 2001, effectively stalling the restructuring of the demand side of the market. At the same time, financial contracts for the years 2001 to 2003 on the energy (both base and peak load) from the PPAs that did not sell in the original auction in August were sold at a second auction. The Balancing Pool retained the dispatch rights to this energy (which it continues in 2001 to bid into the Pool) but the contracts provided fixed price hedges for the upcoming year for both the Balancing Pool and a large number of major consumers and brokers of energy who purchased them at the auction. The prices obtained ranged from \$117/MWh for base load power in 2001 to \$153/MWh for peak periods with an average of \$122/MWh. For 2002, the average price was \$67/MWh and for 2003 it was \$60/MWh – providing a consensus forecast of future electricity prices in the province.

The average price obtained on the 2001 blocks of base load energy sold at this second auction, approximately 11 cents per KWh, was specified to be the Regulated Rate for 2001 for small consumers (residential and small commercial) and the nearly \$2 billion profits from the two auctions were used to provide subsidies to keep residential and commercial electricity bills near their year 2000 levels.

With the re-election of the Provincial Conservative government, the architects of the electricity-restructuring program, in a Provincial election in March of 2001, a mandate of sorts was provided to continue the process. In light of the high profile problems in California, the initial questions remained concerning restructuring: how far and how fast?

4. Restructuring post-January 2001: Current Status

As the following table indicates, Pool prices have been generally falling over the last six months, though they are still much higher than previously.

TABLE 4

Average Monthly Pool Prices

Month	**Average Pool Price** $/MWh
Sept 00	176
Oct 00	253
Nov 00	228
Dec 00	189
Jan 01	131
Feb 01	117
March 01	97
April 01	115

The above price pattern can be explained by several observations. In the early part of the fall of 2000 export markets (mostly to British Columbia, which was exporting to California) contributed to important increases in the Pool price. In November of 2000 a modification to the wholesale pricing system was instituted in Alberta whereby imports and exports were no longer able to set the market-clearing price (though they were still dispatched in the merit order curve). This explains the drop in prices after October. Also of importance is the fact that Alberta, which is winter peaking, had an extremely mild winter in 2000-2001. In addition, natural gas prices began dropping somewhat, which is important because gas is the marginal fuel a great deal of the time now in Alberta. What the above table does not show is that the daily (and even hourly) fluctuations of the Pool price have seemed to move as expected based on supply and demand movements (both internal to Alberta and in the import/export markets).

At this point it would be dangerous to attempt to predict where Alberta Pool prices will be in 2001-2002. The following elements will no doubt have considerable influence on the prices that prevail. Natural gas prices will of course be key, because in the Alberta system gas is the marginal fuel a great deal of the time. Because the Alberta economy continues to be quite strong, it is anticipated that demand growth will be strong. Just how strong demand growth is, will obviously have an influence on prices. Normally relatively high prices would have some dampening influence on demand. In fact, Pool authorities did note a measurable decrease in demand over the past winter that was at least partially attributable to high wholesale prices. The very low precipitation in the Pacific Northwest, coupled with continuing market tightness in California will also play a role in Alberta's market. Even though imports and exports do not set the Alberta Pool price, the shortage of power in the West will affect market dynamics in Alberta. The internal supply situation in Alberta should be moderately better in 2000-2001. A small amount of new capacity is coming online between now and December 2001. In addition, one 280 MW unit that was offline for all of the past winter is scheduled to return to operation for June 01. Though small, this represents 3.5% of peak demand in Alberta, and is therefore significant. Of course the supply margin will continue to be tight, meaning that any prolonged forced outage could potentially cause important price increases in the Pool.

Several longer-term issues need to be addressed in Alberta. Of most immediate concern is the question of construction of new merchant capacity in the Province. A large number of projects have been announced in the last six months. Interestingly, three of these are large coal-fired base-load units. Because of the long lead-times necessary, these large units will not provide relief to the market for 3-5 years. In order for new capacity to be built quickly, the regulatory framework has to be clarified. This includes the permitting process (no new merchant plants have been built since the beginning of the restructuring process) and the regulations and policies in the new market. Regarding the latter question, many different customer classes in Alberta are receiving consumption rebates in 2001 and are being shielded from the Pool price. How long will the rebates continue? More generally, how will retail competition "shake out" in this market?

Also related to clarifying policy, the rapid resolution of the regulated capacity that was not sold in the PPA auctions is necessary. At the moment, the Balancing Pool controls (dispatches) close to 2000 MW. Significantly, the Pool dispatches some of this capacity in uneconomic fashion, thus distorting the Pool price.[10] This obviously can lead to

[10] For instance, the Pool has adopted a strategy of bidding the Clover Bar units at a price set by its long-term natural gas supply contract. Because of high spot prices in the natural gas markets, the Clover Bar bids

reduced value to other Pool suppliers. Importantly, it distorts the signal to potential entrants in the generation market. Getting the Pool administration out of the operation of generation units would most certainly benefit the development of the market.

Finally, the electricity industry needs to continue its development along several related directions. A nascent electricity forward market does exist in Alberta, but it is still immature and very thin. The availability of risk-hedging opportunities will be important for continued development of merchant capacity, as mentioned earlier. Along the same lines, more demand-side responsiveness, possibly through better use of retail metering, would also benefit the development of the market.

have been below their true marginal cost (economic opportunity cost). This is not a profit maximizing strategy.

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