Options for Market Power Mitigation in the Alberta Power Pool

Final Report

Prepared for the Alberta Department of Energy

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Executive Summary

1. The current legislated hedges, which cover the majority of output for the generating stations of the three main vertically-integrated utilities in Alberta, have been successful in restraining generator market power and transferring rents to customers There is some evidence, however, that this hedging structure is distorting current pool prices, which may affect investment decisions by new entrants. The current legislated hedges are also incompatible with the further deregulation of the Alberta power sector and the development of retail competition in the Province.

2. The structure of the generation market in Alberta is unlikely to produce an allocatively, productively and dynamically efficient outcome in the absence of a robust market power mitigation strategy. The concentration of ownership across the generating sector, and especially within the various types of capacity, would allow generators to increase their profits significantly by increasing bid prices or withholding capacity across a range of demand conditions, but especially at periods of low reserve margin. In these periods the market power of all three generators is nearly absolute without some control mechanism or substantial new entry.

3. The potential for new entry into the generation market Alberta is clear, but we consider the threat of entry to be insufficient except over the long-term to discourage the abuse of market power by incumbents. The use of deterrence strategies by incumbent generators must be prevented if the market is to become competitive.

4. A brief review was made of the market rules to determine if changes in the auction design in the Pool rules would be sufficient to reduce market power. While we believe there is some scope for improvement in the rules in the context of market power, we are strongly convinced that such changes will be insufficient to give an economically efficient outcome in the absence of other constraints. The development of forwards markets and other secondary markets should be encouraged, but will not succeed in controlling the market power of incumbents under the current market structure.

5. A replacement mechanism for the legislated hedges should have three main objectives: preventing the abuse of market power, transferring rents (based on embedded costs) to customers from generators, and not distorting Pool prices by affecting utility incentives. In particular we are concerned that it will be difficult to create an appropriate mechanism which does not distort market incentives yet recaptures rents exactly. A future mechanism may require some variation in the precise amounts of rents to be captured by defining some up front lump sum transfer to customers.

6. There are a number of options for controlling market power beyond forced changes in market structure. Auctioned bidding transfers are one such alternative. Bid caps, floors and screens and market surveillance programs have been proposed in other jurisdictions. In this report we consider in some detail the use of imposed contract portfolios to remove the incentives for generators to abuse market power by changing the structure of their payoffs. Such contracts would take the form of long-term contracts

for differences imposed on generators. The extent of contract cover could be substantially less than the existing legislated hedges for most generators and still remove the scope for market power abuse.

7. A total contract cover of 50% or less would appear adequate from our initial modeling analysis to control the market power of the mid-merit and peak plants of Alberta Power and Edmonton Power, with some exceptions. Due to the shape of the supply curve, and its share of the generation market, TransAlta Utilities has the ability to affect prices by withholding capacity across a range of supply-demand days. This could only be controlled by a high level of contract cover, probably over 80% of declared capacity. These estimates of required contract cover are based only on an initial analysis and will require further refinement before the development of specific contractual terms.

8. An alternative mechanism for the control of market power would involve writing long-term dispatchable power purchase agreements with existing generators at embedded cost. These contracts would then be auctioned to third-parties, which would control the bidding of plants into the Alberta Power Pool and be paid the pool clearing price. This mechanism would effectively create new competitors in the pool, avoid distortionary effects of high contract cover, and transfer rents from generators to consumers.

9. Increasing the response of load to high peak prices is a prerequisite for the development of an efficient spot market. Increased use of demand bids will help to constrain the market power of generators across a broad range of demand-supply days. Given the results of our modeling analysis, however, we believe that other measures will also be required.

10. On peak days over the next few years the capacity balance will be very tight. The ability to manipulate prices in the peak periods is closely linked to smaller reserve margins on these days. Unless the demand response in the market changes radically, it will be difficult to design a contract portfolio which controls market power on peak days but does not cover almost all generating capacity. This would in turn affect peak prices and fixed cost recovery by generators, which in undesirable.

11. No available mechanism will meet every one of the Department of Energy’s objectives precisely. The auctioned bidding transfer model appears to fit most of the ADOE’s objectives, if it proves acceptable to Alberta stakeholders. An imposed contractual mechanism (CfDs) appears to be the next most attractive available option, although it will be difficult to determine an exact set of contract quantities, strike prices and durations which meets the objective of transferring the precise difference between the market and book value of existing assets without affecting market outcomes.

1. Introduction

The Alberta Department of Energy (ADOE) has retained London Economics, Inc. to develop alternative options for the mitigation of market power in the Alberta Power Pool. The terms of reference for this study encompass:

- development of an detailed framework for analyzing market power in the provincial power market;

- reviewing the rules of the Alberta Power Pool to determine if changes might be made which would limit the potential for abuse of market power by participants;

- developing a set of alternative mechanisms to replace the existing legislated hedges which meet the objectives of market power mitigation, rent transfer, and non-distortion of market outcomes, while preserving incentives for efficiency and the successful implementation of retail competition in the Province; and

- preparing a set of policy recommendations for ADOE for use in preparing enabling legislation in early 1998 to implement the next steps towards restructuring.

1.1 Scope of the study and report

It is important for stakeholders to fully understand the scope of our analysis and the precise questions which are seeking to address. Specifically, we have made *no* effort to analyze:

- past behavior in the Alberta Power Pool. LE has not reviewed past bids into the Pool, which remain confidential, nor have we sought to determine the past bidding strategies of Pool participants except for the purposes of testing our model of the Alberta system. Our analysis of market power is *prospective*, not retrospective, based on assumptions of future supply and demand characteristics;

- the effects of potential changes in generation market structure in Alberta. The objective of this study is to determine if practical alternatives exist to the divestiture of generating assets by incumbent utilities. While changes in market structure are the preferred solution for curbing potential market power others may exist. Our objective is to determine if these can be applied in Alberta with a strong likelihood of success.

1.2 Structure of the report

The rest of this report is divided into five sections. Section 2 reviews barriers to entry in the industry, whether the Alberta generation market is potentially contestable, and the effects of the existing hedge structure on the future development of the Pool. Section 3 reviews some proposed changes to the Alberta Pool Rules in the context of gaming and market power. These includes changes to the auction design, rules for bidding imports, re-declarations and schedules, and the development of forwards markets.

In section 4, we review the objectives for the replacement of the legislated hedges by a new mechanism, and the alternatives which are available to Alberta. A major focus of this section is the discussion of potential contractual mechanisms for removing the incentive to abuse market power, and the interactions with the retail market development, rent transfer and pricing efficiency objectives. In this section we also propose and discuss an additional mitigation option based auctioned contracts which transfer operational bidding of generating units to third parties.

In Section 5, the modeling process and approach is discussed, along with data sources and model verification. Section 6 reviews the results of the modeling analysis, with and without contractual mechanisms in place. We also report the results of modeling of increased demand response from users, load growth and new entry, and other variables.

The final section summarizes our analysis and presents our policy conclusions for the Department. Given the limitations of available mechanisms the section focuses on the tradeoffs necessary in developing a workable policy for preparing legislation.

2. Barriers to entry and future market development

Our analysis began with the recognition that the Alberta generation sector is highly concentrated among three utilities, and we demonstrate in a later section that in a static sense the three integrated utilities have adequate market power to profitably push up pool prices. However, if the Alberta power market is contestable, then the threat of new entry would discipline the behavior of incumbent generators and prevent the potential abuse of market power. If the market is contestable then the Alberta wholesale market would have a natural cap at equilibrium determined by the new entry price. The most likely cap is the least cost new entrant, which in the Alberta system is likely to be gas-fired combined cycle plant (CCGT) operating as base-load.

Under the contestable markets model, incumbent prices are constrained by potential entry in contestable markets only if a number of stringent conditions are satisfied:[1]

- there are no sunk costs of entry - an entrant can employ a "hit and run" strategy designed to take advantage of high prices as they occur;
- the entrant can enter and take the incumbent's market faster than the incumbent can reduce its price;
- the new entrant can take all of the incumbent's market and has the same cost function as the incumbent.

Although the threat of entry can influence incumbent pricing behavior under slightly weaker versions of these assumptions (in particular, the third assumption can be relaxed), the electricity generation sector is often considered to be a long way from being a "contestable" market, in any relevant economic sense. Based on the high level of sunk costs in the generation sector and differences in cost structure, and the existence of at least some barriers to entry, we conclude that the threat of entry alone is unlikely to provide a sufficient pricing discipline on incumbents for a substantial period of time, if the market were to be opened up without regulatory or other mitigation controls.

Even if potential entry cannot provide the perfect discipline that it does in theory of contestability, actual entry will occur if the barriers to entry are not high. We turn next to an examination of the barriers to entry in the Alberta power market.

2.1 Barriers to entry

There can be substantial barriers to entry into a competitive power market. These derive from a number of different sources, usually classified as follows:

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[1] See Tirole. J (1988), *The Theory of Industrial Organization*, The MIT Press Cambridge, London.

- **natural barriers to entry:** such as those that might derive from exploiting economies of scale (which we argue are relatively small in Alberta in Section 2.1.1);

- **strategic barriers to entry:** which generally derive from being in the market first. These might include sunk entry costs (the three major incumbent generators have 7 GW of plant whose costs are sunk), preferential access to skills and information, or ownership of a portfolio which allows incumbents to manage availability risk more easily than the new entrant;

- **anti-competitive practices** such as bidding in the contract or spot market in a manner which raises new entrant's cost, or cross subsidies between different technologies within a portfolio (for example, incumbent utilities might be able to lower off-peak and mid-merit prices and raise peak prices in order to deter baseload CCGT entry).

2.1.1 Natural barriers to entry and minimum efficient scale

From a technical standpoint the barriers to entry appear relatively low. Transmission access is guaranteed to all generators by the transmission tariff and the Alberta Power Pool is available as a customer for all generated power. From secondary evidence it appears that transmission congestion is limited in the Pool and so there is relatively little strategic advantage in the ownership of existing sites. The value of infrastructure at existing sites may be considerable, but can be handled through the residual value transfer mechanisms if these are appropriately designed.[2] Alberta is a major gas-producing province in a situation of surplus production and natural gas is widely available for additional generation.

Economies of scale permit firms with larger outputs to realize lower average costs and so firms in a market that produce homogeneous products are at a natural disadvantage relative to their rivals if the scale of their operation is small. We note that economies of scale are unlikely to form an effective barrier to entry in the Alberta generation market. If the minimum efficient scale for a new gas-fired combined-cycle gas turbine plant is 500 MW, this accounts for only 5% of the entire market. From this simple analysis we conclude that barriers in the form of the size of an efficient plant relative to the market demand do *not* appear to be an issue.

As a secondary issue, we note that single station generators are generally at a competitive disadvantage as compared to larger portfolio generators in pools. This is due to several factors:

- small generators face proportionally larger risks in writing firm financial hedging contracts to customers than portfolio generators. Consider, for example, the case of a single unit generator with a firm contract for 100% of its output in a day. If the unit is unavailable due to a forced outage in a period of high pool prices, a significant financial loss is incurred. Portfolio generators can more easily manage these risks through their contractual position;

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2 This infrastructure could include grid connection equipment, gas pipeline and lateral access, environmental facilities, fuel mining and handling installations, etc.

- small generators may have trouble selling retail hedging contracts, since the output profile of their plant does not meet the usage profiles of most consumers. This does not pose an issue if the wholesale contract market is liquid, but this contract market is often dominated by larger players with flexible plant., who have little interest in allowing liquidity to develop.

2.1.2 Informational barriers to entry

The costs of acquiring information on the market can pose a barrier to entry in some circumstances. We note that incumbents are likely to have some advantage in terms of their knowledge of:

- **system operations:** as formerly regulated entities the incumbent generators have considerable information on the operation of the generating units in Alberta. Incumbents have access to information on the state of the system through the SCADA system which may be important in a real-time pool design;

- **maintenance scheduling and outages:** in a system as small as Alberta information on specific plant maintenance and outages could be of value in determining bid strategies, especially at peak periods;

- **contractual positions and future bidding strategy:** at present the clearing prices in the pool are set primarily by the interaction of three players. The bidding strategy of players is affected by the contractual position of generators (i.e. if a generator is over-contracted he or she may want the price to fall, not rise). Large incumbents in a competitive market have at a minimum a knowledge of their own contract position and through the wider hedging contract market may have superior knowledge of the position of others.[3] This can serve to reduce the risks of investing in the market.

Although some informational barriers may exist in the market, these are relatively small and would not be expected to prevent entry by sophisticated investors. The history of the Alberta power industry as a set of closely regulated utilities suggests that a higher level of information may be available than in a range of other capital intensive industries.

2.2 Strategic barriers to entry and entry deterrence

Modern economics has recognized the ability of incumbent firms to commit early to strategies that prevent entry. An incumbent firm would prefer always to announce strategies that deter entry so that the incumbent can enjoy a market with reduced competition. Over time, however, the only threats that are credible are those that an incumbent is willing to execute in the face of

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3 This assumes that the wholesale hedging contract market is not highly liquid and transparent. Given the current industry structure it is doubtful that this market could become liquid unless it served the interests of incumbents.

entry. Examples of the potential for entry deterrence include limit pricing and the use of restrictive covenants or contracts to extract rents.

Suppose that plant capacity represents sunk capital, that is capital that has no opportunity cost and cannot be re-deployed for use elsewhere. Installed electric generating capacity has a high component of sunk costs. An incumbent firm *could* find it profitable to commit to an enhanced output (relative to its monopoly output) by expanding its plant capacity to a sufficiently large level. This level is determined as the minimum output such that an entrant calculating its best response to the incumbent's output discovers that the corresponding levels of profits will not sustain entry. This can be labeled "investment to prevent entry." Larger investment in plant capacity are really signals by the incumbent of the degree of its aggressiveness in the post-entry market. Entry prevention by the incumbent need not be the dominant strategy. It is possible that accommodating entry leads to higher profits for the incumbent.

Several parties in the Province have argued that the threat of new entry would play a major role in limiting incumbent behavior through the use of limit pricing. Limit pricing can best be described as the incumbent(s) setting a price at a level just below that necessary to support new entry, in the expectation that prices above this level would result in unwelcome premature entry. The economic rationale for the notion of limit pricing has been the subject of an extensive literature[4] in the past decade or so. Only rarely does this form a rational business strategy. Limit pricing is not generally credible because a new entrant will realize that an incumbent's post-entry pricing will be independent of its pre-entry pricing; prices have little or no 'commitment' value. An entrant will not be deterred by pre-entry pricing if entry is profitable given the incumbent's expected post-entry pricing behavior.[5]

Based on this initial analysis, we would not expect incumbent generators to employ limit pricing, which would help to discipline prices in the market. Instead, we expect incumbents would find it most profitable to maximize profits over the short to medium-term, and to accommodate new entry over longer periods. Due to the time required to site and build new generating facilities, the Alberta generation sector could take a considerable time to reach a competitive equilibrium even if entry barriers are low.

In summary, we expect that market power problems in the absence of some form of mitigation mechanism or direct regulatory controls will not be resolved until a sufficient number of new plants could be brought into the market to make the physical spot market workably competitive. As we will see in a later section the level of new entry required to make the Alberta market reasonably competitive is well in excess of 1000 MW.

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4 See pages 367-373 of Tirole (1988) *op. cit.* for a discussion of the literature.

5 Limit pricing may be credible in rare circumstances where the incumbents pre-entry price informs the new entrant about the incumbents costs or market conditions. However, there is considerable information available concerning costs and conditions in the [pre-entry] power market (not least because of regulation induced information disclosure), so this is unlikely to be the case in the Alberta power market.

2.2.1 Initial contractual positions

The use of contractual arrangements to exclude entry can be quite simple, if distributors or customers are sufficiently concerned about market power and price volatility in the initial stages of development of the market.[6] Incumbents may offer counterparties longer-term (one to three year) contracts at prices well above their cost. If they are nearly fully contracted they are immune to low pool prices and can bid into the pool at close to marginal (i.e. fuel) cost, but below average cost (including fixed capacity costs). This strategy allows incumbents to extract rents over the short to medium-term while delaying entry by pushing down prices in the pool. The potential benefits of this strategy over simply raising prices can be twofold:

- capturing rents through the use of commercial hedging contracts rather than the pool has a lower element of regulatory risk, since these arrangements may not be subject to regulatory review; and

- if new entrants can be successfully excluded then the strategy can be repeated in the next round of contracts, through the continued threat of higher prices if customers do not hedge themselves.[7]

2.3 Market development and foreclosure

The current industry structure, where the incumbent vertically integrated generators are almost completely insulated from the pool price by the legislated hedges, has helped to produce a set of counter-intuitive outcomes in Alberta:

- pool prices in general appear to have been well below average costs, as incumbent generators have been able to recover their fixed costs through the legislated hedges rather than the market. This has been a significant disadvantage to potential new entrants, who face competition with entities which are recovering the majority of their fixed costs from a set of contracts from which they are excluded;

- pool prices have been set by the bidding interaction of incumbents with limited incentives for market prices to rise, given their general net contractual position against the legislated hedges. Short-term gains from increased pool prices would be offset by the increased losses from plant not available and the future competitiveness of the market;

- the Alberta Power Pool has seen little in the way of new entry, despite being relatively short of capacity and with rapidly growing demand. While the availability of long-term hedging arrangements in Alberta might assist new entry, it is not a prerequisite for investment by

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[6] Incumbents will be the primary sellers of these contracts, as they are able to hedge the risks of high market prices if they indeed control pool prices. The potential use of such a strategy would depend on a high degree of risk aversion among customers.

[7] The general use of an annual contract round for signing contracts would greatly aid in the payoffs from this strategy.

sophisticated equity and debt participants. Other competitive markets with a need for new capacity (none of which to our knowledge are as tight on reserve margin as Alberta) have seen a flood of announcements for new merchant generation;[8] and

- the longer-term contract market appears fairly illiquid, and offers little in the way of pricing signals or risk hedging opportunities for new entrants facing considerable uncertainty about post-entry prices and high incumbent sunk costs.

In conclusion to this section, the current cover level of the legislated hedges has proved an impediment to the development of the provincial power market. Much of the potential market demand has been foreclosed from entrants through the legislated hedges. The actual contestable market in Alberta is in effect small, illiquid, and highly subject to the pricing decisions of incumbents which are generally isolated from it. In the next round of deregulation an additional major policy objective must be to remove these structures which can serve to distort competition, while continuing to mitigate the worst potential for market power abuse.

8 Over 4,000 MW of new gas-fired merchant generation has been announced in the New England Power Pool area, for example. Relatively little of this generation is covered by long-term contracts. Over 10,000 MW of essentially merchant generation has been announced across the United States.

3. Market design review

The terms of reference for the study asked us to comment on potential changes to the market rules in Alberta which might alleviate the market power problem. In this context we confine our comments on proposed changes to the Pool rules to their likely effect on the potential for the abuse of market power in the provincial generating sector.

The fundamental conclusion of this review is that although there are beneficial changes to be made, no changes in the Pool rules are likely to produce an efficient competitive outcome given the current market structure, in the absence of a market power mitigation mechanism to replace the legislated hedges. If no change in market structure is possible then another means of market power control must be identified before removing the legislated hedges, if deregulation is to move forward.

3.1 Demand-side bidding

Price responsive bids from loads are generally necessary for full efficiency of the power market, and in particular they can suppress peak prices and reduce volatility. The industrial loads in Alberta appear to be natural candidates for price-sensitive curtailable-service contracts. Increased demand-side bidding is also consistent with current plans for self-commitment of generation, which entails decentralized demand forecasting by suppliers. Demand-side bidding could also obviate a significant role for price caps, and reduce incentives for major suppliers to deter entry by stretching the price-duration curve so as to render new base-load supplies uneconomic.

From a market-power perspective, however, it is important to recognize that some of the potential of demand-side bidding to enhance efficiency could go unrealized in Alberta. The chief impediments are the level of legislated hedge cover and the role of the three vertically integrated firms, who currently have, and would likely continue to have, direct or implicit contracts to hedge prices between their generation and distribution subsidiaries. For these firms the price in the power pool is akin to a transfer price between subsidiaries. Due to this feature these firms have muted incentives to solicit interruptible and curtailable contracts with industrial customers, since such contracts increase the elasticity of demand and thereby diminish the monopoly power of the major suppliers. (In most economic models, market power as measured by the price-cost margin is generally proportional to the reciprocal of the demand elasticity).

As a practical matter, the effectiveness of demand-side bidding depends substantially on the efforts of each distribution company to offer and promote curtailable and interruptible service contracts with major industrial customers. But one can expect that to whatever extent these contracts would reduce the overall market power of the vertically-integrated firm, these efforts will be suppressed or minimal, and indeed presently much of the potential for curtailable service in Alberta is unrealized. For example, if entry deterrence depends on stretching the price-duration curve to keep base-load prices low, while recovering the difference through higher peak prices, then curtailable contracts that enable demand-side bidding will be avoided in order to sustain the inelasticity of demand and thereby retain the prospect of high peak prices.

There are measures that could be adopted to enhance the effectiveness of demand-side bidding in improving overall efficiency. The most obvious is to impose a requirement on the regulated distribution subsidiaries that they offer curtailable-service contracts to industrial customers at prices reflecting the pool price. This would have the net effect of enforcing a separation between the generation and distribution subsidiaries of the vertically integrated firms. That is, ensuring that demand-side bids for interruptible loads get reflected in the clearing price in the Pool weakens a vertically integrated firm's motive to treat the Pool price as merely a transfer price between subsidiaries by some amount.

3.2 Price re-declarations

The Pool has indicated its interest in allowing re-bidding of prices and quantities up to one or two hours before final dispatch. This change from day-ahead bidding could improve the accuracy of the information for dispatch because often there are material changes in supply and demand conditions in the interval between the day ahead and the hours before dispatch. "Closing the gate" a full day ahead commits the bidders to the results of an optimization based on data that may be inaccurate when the time for dispatch arrives. In fact, of course, the Pool allows suppliers a single re-declaration before dispatch, but this option need not suffice for fully efficient operations.

On the other hand, the proposed scheme has deficiencies that must be corrected if the potential advantages of re-bidding on a short time frame are to be realized. The problem stems from the fact that continual re-bidding provides no incentives for suppliers to submit "serious" bids early in the process. That is, because the early bids are not commitments, a supplier bears no irreversible consequences from its initial bidding, and only its final bid affects its unit commitment, dispatch, and the spot price.

This problem has two consequences. One is that price discovery is unreliable. During the bidding process before the final bidding, a supplier has no positive incentive to contribute information about its supply availability and prices. Indeed, its preference will ordinarily be to wait until the final bidding to declare its true availability and offered prices, because it can then base its bid on the opportunities revealed by others' bids. When a substantial portion of supply waits for price revelation by others' bids, there may be no effective price discovery, or the interim prices may be volatile and unreliable. In other dynamic bidding processes (such as in the US spectrum auctions, and in the iterative power auctions in California), this problem is addressed by imposing an "activity rule." Essentially, an activity rule requires each bidder to make increasingly restrictive and irreversible commitments as the bidding process proceeds. Usually these commitments take the form of "use it or lose it" options that encourage each bidder to make serious bids at each stage. Activity rules are presently the most successful means of ensuring reliable price discovery, but when the complete auction design is prepared other methods might be considered for use in Alberta.

The second consequence is that the bidding is subject to substantial manipulation. Because early bids are not commitments, they can be used to affect tentative prices in ways intended to thwart reliable unit scheduling by others, or to render pricing so volatile and risky that entry is deterred. Suppliers with thermal units having substantial start-up and no-load costs, for example, could find it difficult to self-schedule the operating regimes of their units, as compared to hydro units with much greater flexibility in adjusting to short-term price movements. The present problem in Alberta with multiple declarations of virtual units by importers, some of which are then withdrawn depending on later indications of prices, shows that manipulation is a likely outcome.

One model for how to address these problems is provided by the design of the California power market. There, a sequence of three markets is used. The first is a day-ahead market, the second is a (two-) hour-ahead market, and the third is a real-time market. The key feature is that transactions in the day-ahead market are financial commitments; then residual adjustments can be made in the hour-ahead market; and finally, some generation can be adjusted in the real-time market. In each case, transactions in the current market are settled on the basis of the clearing price there, but later market(s) allow adjustments to cope with changed circumstances of supply and demand. Thus, there is a day-ahead forward price, an hour-ahead forward price, and finally a real-time spot price. In addition to this sequence of markets with financial commitment at each stage, the California design imposes an activity rule during the iterations of the day-ahead market to ensure reliable price discovery there.

The California design is not directly applicable in Alberta because one must suppose that here the current preference for *ex post* pricing will continue; that is, all settlements must be based on the real-time price. This being the case, it will be necessary to develop new activity rules that address the peculiarities of the Alberta situation. In particular, since all prices are pegged *ex post* to real-time prices, the design of the activity rules will need to focus on devices that ensure progressively more restrictive commitments to availabilities and quantities. In designing these new rules, it will be useful to take account of the following basic structural features.

In general, when self-scheduling is used, substantially reliable price discovery must be provided when the earliest unit commitments are made. For cycled thermal units with significant start-up costs and ramping durations, that time is typically a day ahead when they need to plan their starting times and running durations. In contrast, quick-start and hydro units can usually defer commitments until a few hours ahead. These considerations indicate that at a minimum the activity rule should provide partial price discovery a day-ahead, with allowance for refinements two hours ahead, much as in the California model. How this can be done without financially binding transactions before the real-time dispatch is unclear presently, but the current procedures provide some guidelines. For instance, presently the declarations of availabilities and price-quantity bids are committed a day-ahead, with a single re-declaration allowed. One can envision that some version of these restrictions on re-declarations can be the basis for specific activity rules that provide the necessary degree of price discovery. Alternatively, if some financially binding transactions can occur early, such as a day ahead, then the activity rules might be adapted from the California design. This seems more likely when one considers that major improvements in the settlement process are contemplated in any case, and these improvements might include provisions for settlements based on day-ahead transactions.

3.3 Import bids

As mentioned in the section on price re-declarations, price discovery is an essential part of any dynamic bidding procedure that relies on self-scheduling by suppliers. In Alberta, importers presently enjoy the benefits of seeing tentative prices before they must make their final commitments. They obtain this advantage from their privilege of declaring multiple virtual units on a day-ahead basis, any of which can be withdrawn later. A portfolio of virtual units can be designed to take maximum advantage of circumstances on a short time frame such as a few hours. Some units are withdrawn in favor of those most profitable based on the current projection of the real-time prices. This is an advantage that other suppliers want as well, which is one explanation for the plan to allow frequent or continual re-bidding up to a short time before dispatch. On the other hand, the volatility in tentative prices caused by the importers' virtual units is indicative of the more severe problems that are likely to arise if continual re-bidding is implemented without any activity rules to ensure steadily more accurate price discovery as the dispatch time approaches.

One should recognize that the advantage accorded presently to importers likely enhances efficiency, since it enables them to adapt their actual deliveries to more accurate price projections; e.g., it suppresses peak prices. Similarly, opportunities for other suppliers to re-bid on short time frames can also contribute to efficiency. The important auxiliary consideration, however, is that something like a sequence of financially binding markets, or stringent activity rules, are also needed to channel the re-bidding process so that tentative market clearing prices early in the process are sufficiently accurate indicators of settlement prices that, say, cycled thermal units with significant start-up costs can confidently plan their unit commitments.

3.4 Physical bilateral contracts and bid disclosure

The Alberta Pool is mandatory, but consideration has been given to allowing physical bilateral contracts that could be transacted outside the Pool. Usually a mandatory pool is desirable to improve system optimization, especially to avoid potential inefficiencies in the utilization of transmission assets, but with little transmission congestion within Alberta this argument has less force. Absent transmission congestion, and with allowance for self-scheduling as proposed, there seems to be no inherent necessity of mandatory participation in the Pool.

The strongest argument in favor of allowing bilateral contracting is that it undermines implicit collusion by enabling secret price cuts. Because the three vertically integrated firms in Alberta supply a dominant share of the market, it is important to stimulate competition among them - and allowing private contracting is one means of doing this. One cannot be sure, however, that non-Pool contracting will suffice, since with just three firms the incentives to abide by implicitly collusive understandings and market partitioning remain strong. The advantages in terms of encouraging entry may be more reliable, since presently entrants' prospects of contract cover from distribution companies are slim, whereas bilateral contracts with industrial customers may provide a firmer basis for entry.

The potential market power problems in the Alberta market stem from the dominant role of the three major firms. Arguments have been made that greater transparency in the bidding process would subject these firms to more political pressure to moderate their use or abuse of market power, simply because egregious instances would be observable. These arguments are especially persuasive given the collapse of the committee with market-power surveillance responsibilities. Transparency has other advantages as well, of course, including public confidence in the process, and better information for prospective entrants.

On economic grounds, however, a fully transparent bidding process is more likely to facilitate implicit collusion that to undermine it. Privacy of bids, with only the aggregate dispatch schedule and the final prices being reported by the Pool, hinders efforts by the three major firms to monitor each other's adherence to norms or understandings or market segmentation. Reforming the authority of the committee to monitor market power, and its reporting structure to provincial or national regulators, seems a more tenable solution.

3.5 Markets for forward contracts

One of the current proposals for reforming the Alberta market is to develop an organized market for forward contracts. Presumably this proposal does not refer to designs like the California market that has day-ahead and hour-ahead market clearings for forward contracts based on physical delivery, but which in effect are only financial commitments since deviations can be made up in the later hour-ahead or real-time markets. Instead the likely model is the Finnish market that depends solely on active trading of financial contracts to establish prevailing prices in the absence of a pool to calculate clearing prices. In Alberta, all settlements are based *ex post* on the real-time prices, so the purpose of forward markets would be to trade financial contracts that provide hedges against the real-time price -- and indirectly to allow arbitrage of the real-time market. For example, among suppliers those with cycled thermal units might welcome the opportunity to hedge, since with self-commitment and without binding day-ahead transactions, they are exposed to risks that spot prices will not justify the operating schedules to which they must commit a day or many hours in advance; and equally, hydro suppliers might prefer to be the suppliers of such hedges since they are much less exposed to price risks. On a much longer time frame, distribution companies could substitute forward contracts for the legislated contract cover that they presently depend on. In general, on economic grounds there are ample reasons for predicting that an active market for forward financial contracts will improve efficiency.

These are not the arguments motivating the proposal for an organized market for forward contracts, however. Rather, the hope is held that an formal competitive forward markets will temper the potential market power of the three firms that are dominant in the Alberta market. Our conclusion is that this is an unlikely prospect. At best, a market for forward financial contracts of any moderate duration can only hedge and indirectly arbitrage the real-time spot price that is based ultimately on physical deliveries. As long as the dominant firms control most of the physical supply on which the spot price is based, their market power is unaffected by the forward market. And by controlling the bulk of the physical supplies in the spot market, the dominant firms could probably exert considerable power in the forward market as well, and in ways that are more difficult to monitor and regulate.

There are two qualifications to this conclusion. As mentioned previously, one is that very long term contracts could potentially substitute for the legislated contract cover; moreover, they might also provide a toe-hold for entrants that would enable them to compete on the basis of new capacity additions that over the long term must eventually supplant the present embedded capacity. However, it is important to realize that a market based on very long term contracts would be essentially bilateral, and if such a market were very active the Pool would become a marginal market for residual trading.[9] The second qualification is that retention of the dominant firms' market power in the spot market is likely to make a forward market difficult to sustain, since traders providing hedges in that market would be subject to risks of spot-price manipulations by the dominant firms. We anticipate that the dominant firms could kill off the forward market if they found that it worked against their interests.

3.6 Auction design

One subject about which we were asked to comment is whether an iterative auction, as in California, could mitigate the market power of the dominant firms in Alberta. The direct answer to this question is No. The iterations in California's day-ahead market have a limited objective, which is to provide sufficient price discovery to enable suppliers with thermal generators having substantial start-up and no-load costs to plan their unit commitments. The typical situation is that the owner of a cycling unit must decide each day whether to operate the next day, the starting time, and the length of the operating run. The iterative process provides increasingly more accurate information about the pattern of prices over the next day, and thereby enables development of a profit-maximizing schedule of operations. These considerations have no bearing on the ability of the dominant firms in the Alberta market to use or abuse their market power, which remains intact regardless of the iterative structure of the auction. In particular, these firms have sufficient generation resources to affect the market price (e.g., by withholding capacity to raise prices generally, or by stretching the price-duration curve to deter entry) even in an auction with an iterative structure.

There are, however, some minor advantages that an iterative auction with stringent activity rules could provide. One of the potential abuses of market power is manipulation of tentative prices during the process of continual re-bidding that has been proposed by the Pool. Restructuring the re-bidding process so that it is regulated by activity rules during a formalized iterative procedure could prevent this kind of manipulation, and would provide reliable price discovery that would contribute to enhanced efficiency in a market that relies on self-scheduling of unit commitments. However, the effectiveness of activity rules in improving scheduling is necessarily limited in Alberta since settlements here are based *ex post* on the real-time prices, unlike California where transactions in the day-ahead and hour-ahead markets are financially binding and therefore provide firm day-ahead prices on which the schedules of thermal units can be based.

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9 The spot market would continue to have a major role in setting contract prices, however.

3.7 Conclusions

Many of the market design changes under consideration in Alberta, while holding some potential for direct improvement in commitment and dispatch efficiency, would appear on initial examination to worsen, not improve, the market power problem. Shifting pricing decisions to the hour ahead, for example, will probably aid in collusion and disrupt effective price discovery.

While we fully support the development of a forwards market, we are convinced that a functioning forwards market and changes to the auction mechanism will be insufficient to deal with a potentially severe market power problem. Such a problem is best tackled through changes in market structure, or through auctioned bidding transfers or imposed contractual portfolios.

From our brief review of the current market arrangements, we recommend that:

- consideration be given to allow bilateral trading outside the Pool, as a method for undermining collusion;
- the development of release rules on import transmission capacity, to prevent strategic scheduling of the BC-Alberta tie line as a form of capacity withholding;
- development of some form of activity rules covering re-declarations of capacity and prices;
- removing the special rules allowing multiple virtual units for importers; and
- continuation of the current rules on the release of bids, but with provisions for ready disclosure of bid data to regulators and a market surveillance group. The latter should be reconstructed, as discussed in a later section.

4. Market power mitigation options

4.1 Introduction

This section reviews the options that are available to either reduce market power or to mitigate the worst effects of market power in the Alberta power market, and in particular, market power in generation. It focuses on three potential mechanisms which can be used singly or in combination: contracts for differences; auctioned biding transfer contracts, and bid caps and price screens.

These are not the only market power mitigation options. For example market power concerns in Southeast Australia were partially allayed by structural reform of generation involving some break-up of generation portfolios prior to privatization. In England and Wales (E&W) the regulator sought a limited divestiture by the larger incumbent generation businesses in combination with a short-term cap on pool prices. In South Australia and New Zealand, both of which are short of capacity, the incumbents were not allowed to either develop or take part in the development of additional new capacity, preventing them from consolidating their positions of market power. Forced divestiture has been ruled out in Alberta, so we do not consider these generation structural options in this report.

4.1.1 Allocation of generation rents

The Alberta power system is currently short of capacity, and hence must present prices to the market that support new entrants. The revenue that the existing generators would earn at these prices would yield asset values considerably higher than the book value of the assets. Revaluation of the assets to reflect their anticipated discounted cash flow at such market prices would provide a windfall gain to the shareholders in the company. The Alberta Government has decided that this additional rent should be passed to customers. Thus, the market power mitigation options must be consistent with this requirement.

4.2 Market power in electricity markets

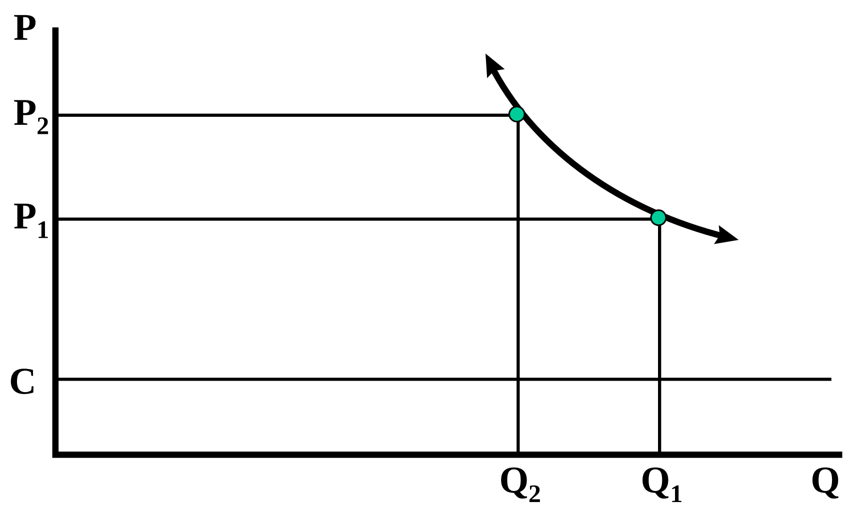
Market power exists in the spot market where there are non-competitive Nash[10] equilibria where bidders choose to raise prices or withhold capacity in order to increase profits. In a perfectly competitive market, a bidder would be unsuccessful at increasing its payoff by either

[10] A Nash equilibrium is a near-universally employed solution concept for non-cooperative games in economics and industrial organization theory. A Nash equilibrium exists when, for a given set of strategies chosen by other players, each player's strategy is a best response to those strategies. That is, in a Nash equilibrium, a player's payoff will decrease if it changes its strategy, assuming that all other players continue their existing behavior. Hence a Nash equilibrium is a best response equilibrium in the sense that no player prefers to make a different strategy choice given the strategies being played by every other player. Cournot or Bertrand equilibria in oligopoly theory for instance, are both different types of Nash equilibria. What differentiates them is the strategy choices available to firms; under Cournot 'behavior' these are quantities of output, and under Bertrand behavior these are prices for each firm.

of these strategies through the normal functioning of the market - i.e. the lost profit from using the strategy would outweigh the additional profits from higher prices on the remaining production.

This is illustrated in a simplified fashion in Figure 1. By bidding its costs, P_1, Generator A produces a total of Q_1 MWh in the hour, at a clearing price of P_1. This price and quantity is in practice set by the bids of all the players in the market, but for the purposes of this example assume that only Generator A chooses to change its bids away from cost. The profit in the hour is equal to $(P_1\text{-}C) *Q_1$, assuming that costs are constant.

Figure 1: Effect of raising bids or withholding capacity



Generator A can change its output by raising the bid prices (so that some units are out of merit and do not run) or by withdrawing capacity from the market. This produces a price and quantity of P_2 and Q_2. The profit in the hour from this strategy is $(P_2 - C) * Q_2$. This strategy can be profitable only if the proportional rise in price outweighs the proportional loss of quantity.[11]

[11] I.e. if the generators own demand elasticity is high, such that its quantity falls by a large amount in response to a small price change, then raising price is unlikely to raise profits. Alternatively if its demand elasticity is low, then an increase in price does not result in a large decreases in its own demand, and it is likely to increase profits by raising price. The generators own demand elasticity is a function of the overall demand and supply elasticity of the market.

In the Pool bidding context we can envision several possible outcomes of applying such a strategy. These include:

- **perfectly competitive outcome:** In a perfectly competitive market Generator A would lose all output Q from raising prices, making the strategy clearly unprofitable. This "textbook" outcome is unlikely the actual power market;

- **highly competitive outcome:** By raising its bid, Generator A loses a large amount of output to other generators, which do not raise their bids. In this case P_2 is not significantly greater than P_1, and the lost output makes the strategy unprofitable — a demand side response may also minimize the extent of any price increase. The quantity Q_2 demanded at the new equilibrium price lowers Generator A's profits below the initial level at P_1, Q_1. From this result we conclude that Generator A has no market power;

- **no changes in price:** if Generator A's unit was infra-marginal (i.e. not setting the Pool price in the hour), it can raise price up to the level of the clearing price without lowering its output. The clearing prices and outputs do not change; and

- **no changes in quantity:** if there is an insufficient demand response, or no other generating units are available at that price, Generator A could see the clearing price rise with no or little corresponding drop in output quantity. In this situation the bidding strategy would be successful at raising profits and Generator A would have clear market power.

4.2.1 Relationship between the pool and contract markets

The foregoing focuses on market power in the pool or spot market, but in most power markets the majority of trade takes place through longer-term contracts for differences, typically of one or more years duration. The interaction between contracts and the pool have been studied in E&W[12] leading to the following conclusions:

- contracts will tend to put downward pressure on pool prices, if generators' contract coverage is sufficiently high;

- *ceteris paribus* generators will have an incentive to sell fewer contracts than they would in a competitive market in order to retain their market power in the pool; and

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12 For example: Helm, D. and Powell, A. (1992) "Pool Prices, Contracts and Regulation in the British Electricity Supply Industry," *Fiscal Studies*, vol. 13, pp. 89-105; Armstrong, M., Cowan, S. and Vickers, J. (1994) *Regulatory Reform - Economic Analysis and British Experience*, Oxford University Press: Oxford.

- contract prices (or premiums) will be above competitive levels as a result of prices above competitive levels in the pool. Hence generators will achieve oligopoly rents in contracts as well as in the pool.

This last observation is of particular importance. It shows that generators with market power will only voluntarily enter into contracts if those contracts embody the oligopoly rents they could otherwise earn in the pool. These contract might subsequently make the pool appear competitive, but would not eliminate the rents from market power. Hence, contracts that are designed to mitigate the effects of market power will have to be based on arbitrated prices that remove these rents. The second implication of the observation is that contracts that can be shown to mitigate market power in the pool will also mitigate market power in the related contract markets.

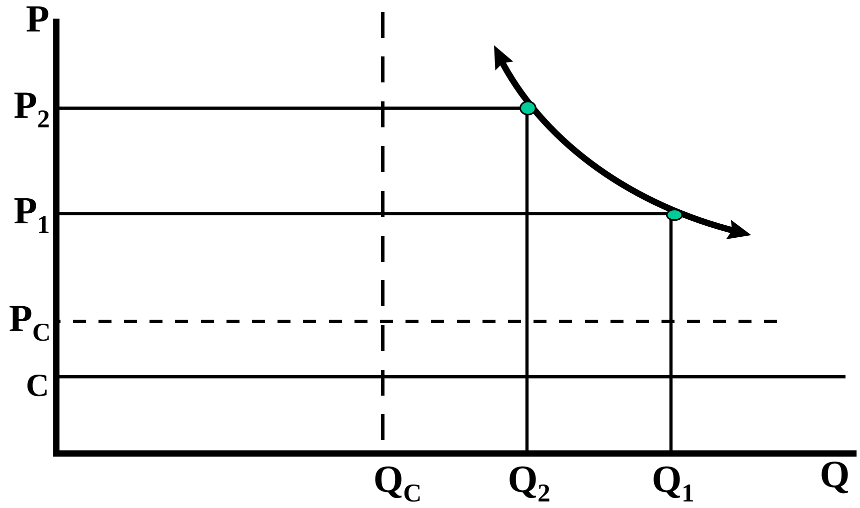
This principle underlies the analysis described in Section 5, in which we determine the payoff from different bidding strategies by generators, calculating new market clearing prices and generator outputs for each hour. By looking at the interactions of the generation and demand bids, it is possible to estimate the shape of the price-quantity response function (the curved bold line in Figure 1) to determine if equilibria exist where P and Q can be profitably manipulated by generators.

4.3 How contracts reduce market power

The imposition of fixed price contracts at which generators must sell some portion of their output changes the profitability of these strategies, as shown in Figure 2. Consider a fixed price contract in the hour, for a quantity of output Q_c at a price of P_c. The profit from operating at P_1, Q_1 is therefore $(P_c - C)*Q_C + (P_1 - C) * (Q_1 - Q_C)$. The additional profit accruing to the generator from raising price or withdrawing capacity is now changed by the amount of contract cover Q_C. By moving to P_2, Q_2 the generator now makes a profit of $(P_c - C) *Q_C + (P_2 - C) * (Q_2 - Q_C)$.

The effect of imposing the contract is to reduce the “leverage” of raising prices and losing marginal output. By fixing the price received for some proportion of output (e.g. a base-load plant), the net profit from raising prices by bidding up a marginal unit (and losing output on that unit) is reduced. In the diagram the net increase in profit has been reduced by the rectangle with area $(P_2 - P_1) * Q_C$. By choosing Q_C carefully it is possible to remove the incentive to manipulate prices and quantities with levels of contract cover Q_C well below the output of the generator’s portfolio of plants.

Figure 2: Using contracts to alter generator payoffs

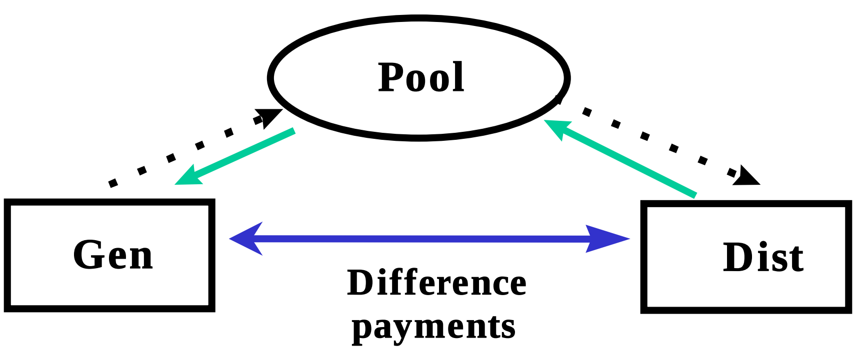


In the context of the Pool these contracts would take the form of contracts for differences (CfDs). A CfD is a *financial* hedging contract referenced against an unknown spot price. In a market with bilateral contracts outside the pool these contracts could be physical bilateral contracts with imposed prices and quantities. The effect on generator profits and payoffs is basically similar under both physical and financial contracts.

4.3.1 Contract forms

CfDs are financial instruments in which one counterparty agrees to pay to the other the difference between the contract price and the prevailing pool price (illustrated stylistically in Figure 3 showing a difference contract between a generator, Gen, and a distributor, Dist.)

Figure 3: Payment streams under a CfD



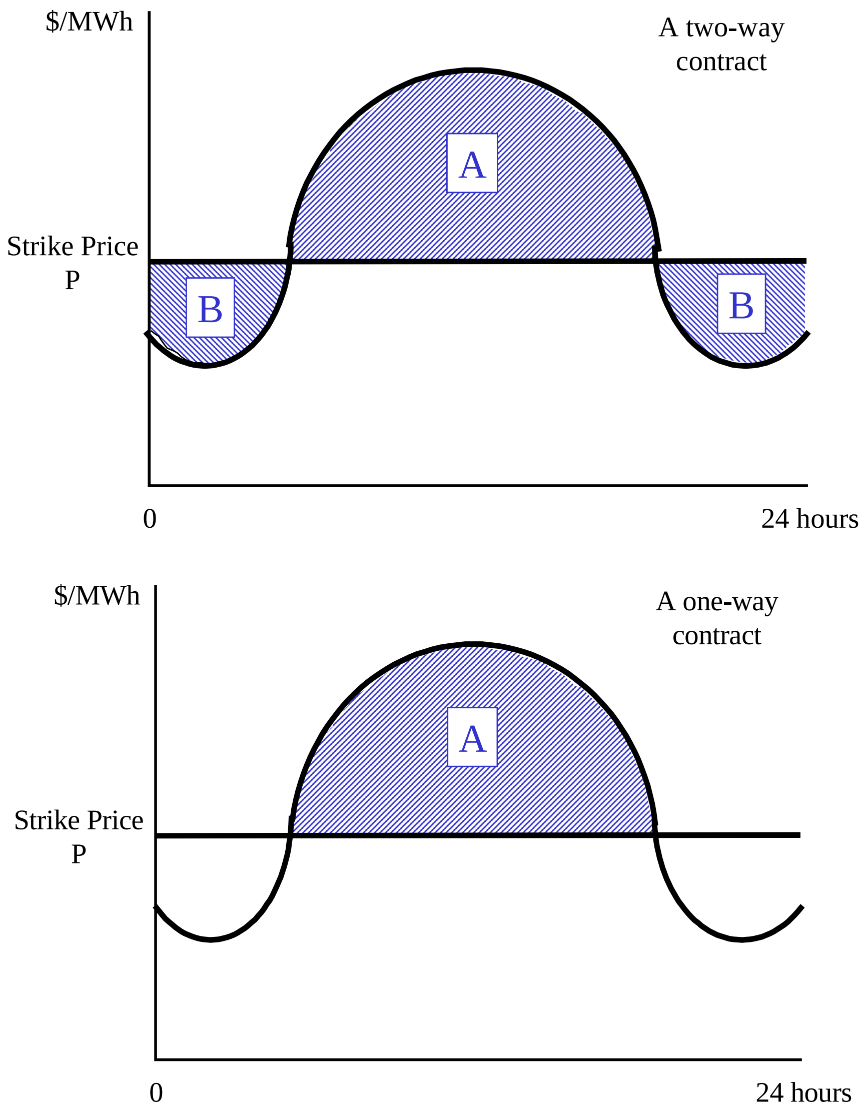
For example, if the pool price is $40/MWh and the contract price is $25/MWh, the seller of the contract is then required to pay to the buyer of the contract $15/MWh, the difference between the two. These contracts are widely used in financial markets. There are two forms of contracts in common use in power markets based around power pools, illustrated in Figure 4:

- a **two-way** contract (analogous to a financial futures contract) is usually defined solely in terms of a MWh quantity and a $/MWh *strike* price. For the defined quantity, the seller agrees to pay the difference between the contract price and the pool price to the seller. Thus, if the pool price is below the contract price, then the buyer pays difference payments to the seller *but* if the pool price is above the contract price, then the seller pays difference payments to the buyer; and

- a **one-way** contract (analogous to a financial option contract) is usually defined in terms of a MWh quantity, a $/MWh strike price and a fixed $ payment or option fee. Under a one-way contract the seller of the contract agrees to pay difference payments to the buyer *only if* the pool price is above the contract price. If the pool price is below the contract price, then no difference payments are made.

The two-way contract has the effect of fixing wholesale purchase costs (or revenues) for the contract quantity at the specified contract price, irrespective of the underlying pool price. The one-way contract caps pool prices for the contract quantity at the contract strike price.

Figure 4: The operation of two-way and two-way difference contracts



In the one-way contract the seller only pays difference payments if the pool price rises above the contract strike price, represented by area A. The buyer pays an option fee for the contract, which will be generally be equal to the risk adjusted net present value of the stream of future difference payments.

Under the two-way contract (above), the buyer pays difference payments to the seller when pool prices (shown by the solid line) are below the contract strike price P, represented by area B. Conversely, when the pool prices are above the contract strike price the seller makes difference payments to the buyer represented by area A.

Thus CfDs modify the revenue that generators earn from the pool by fixing or capping revenue on a proportion of power sold. A generator that has all its output covered by contract has no exposure to the pool, and its revenues are then determined solely by the contract terms. A generator that has no contracts is fully exposed to the pool, so its revenues are determined by pool outcomes. Generators with market power are able to sustainably change the pool prices in order to raise their profits. In the absence of contracts they could manipulate pool prices and raise profits. When fully contracted such behavior would have no effect, because any extra profits from gaming in the pool would be paid out to customers under the terms of the CfDs. If a generator earns no additional profits from gaming in the pool, then it has no incentives to indulge in such behavior.

Thus one can obviate any abuse of market power by contracting all the output from generators using CfDs. This is effectively the structure of the current legislated hedges. However, such heavy-handed intervention is unlikely to result in a wholesale market that meets the Government's objectives, not least because a fully contracted generator generally has incentives to force pool prices down, for two reasons:

- if there is some prospect of relaxation of the contract coverage in the foreseeable future, incumbent generators have an incentive to deter entry (by reducing pool prices). They deter entry by decreasing current wholesale prices, which then results in higher future wholesale prices when CfD cover is relaxed; and perhaps more importantly;

- a generator that has a CfD is required to pay difference payments to a customer if pool prices rise above the CfD strike price. Normally when this occurs the generator is operating, and so receives the pool price for its output. Hence, its overall revenue is given by its CfD strike price. However, generators have a non-zero risk of failure. When they fail, they are still obliged to pay difference payments under their CfDs, but have no pool income. Thus, they are fully exposed to the pool price. Reducing pool price reduces their financial exposure in the event of failure. This is particularly important at peak times when supply is limited.

Generally, there is some compromise level of contract cover below 100% cover which sufficiently reduces incentives for incumbent generators to abuse their market power but does not give them incentives to push down pool prices. Careful selection of these contracts will yield a pool price that proffers allocatively efficient prices, which reliably signals the market risk, and encourages efficient consumption and investment decisions. The text box on the following pages (Figure 5) provide some stylized numerical examples of two-way contracts used to manage market power.

Figure 5: An example of CfDs managing market power

Table T1 shows the pay-off from a game played over a single time period in a market with three generators. Two of the generators, A and B, are strategic players willing to change bids into the pool in order to raise profits; their variable operating costs are $10/MWh. The third unseen generator is not strategic, and simply takes whatever market share that it can given the behavior of others. In this example there are no contracts. The two Nash equilibria in this case occurs when A and B bid high (at twice their marginal costs), and when they both bid low (at their marginal costs). The latter is *dominated* by the former, such that the participants would always find the high/high equilibrium, since it better for both strategic players. At this equilibrium they experience some loss of output to non-strategic generators, but the increase in pool prices more than compensates for this loss.

Table T1. Payoff from gaming in the pool with no contracts

Output (MW)		Generator B bids: Low @ cost (10$/MWh)	Generator B bids: High ($20/MWh)	
Generator A bids	Low @ cost (10$/MWh)	50	70	A output
		50	20	B output
	High ($20/MWh)	20	40	A output
		70	40	B output

Pool prices ($/MWh)		Generator B bids: Low @ cost (10$/MWh)	Generator B bids: High ($20/MWh)
Generator A bids	Low @ cost (10$/MWh)	$13	$15
	High ($20/MWh)	$15	$20

Difference payments ($)		Generator B bids: Low @ cost (10$/MWh)	Generator B bids: High ($20/MWh)	
Generator A bids	Low @ cost (10$/MWh)	$0	$0	A differences B differences
	High ($20/MWh)	$0	$0	A differences B differences

Profit ($)		Generator B bids: Low @ cost (10$/MWh)	Generator B bids: High ($20/MWh)	
Generator A bids	Low @ cost (10$/MWh)	$150	$350	A profit
		$150	$100	B profit
	High ($20/MWh)	$100	$400	A profit
		$350	$400	B profit

We can then determine the effect of imposing two-way difference contracts on each of the two strategic generators. The contracts are priced at $13/MWh which is the expected pool price in the competitive market equilibrium that occurs when both generators bid their costs. The example shows two different contract cover levels — 30MW on each generator and 40MW of cover.

Figure 5: An example of CfDs managing market power cont…

Table T2 shows the impact of applying 30MW of contract to each generator, A and B, priced at $13/MWh. If they both bid low, then they have to make no difference payments, and their payoff is identical to the payoff in Table T1. However, if one or both of them bids above cost resulting in an increase in pool prices, they then have to pay out some of their extra profits through increased difference payments. This changes the outcome of the game significantly. There is now only one Nash equilibrium when both bid their marginal costs — the competitive outcome. So, for example, if both players initially bid high, then either player A or B can do better by changing their bid to low.

Table T2. Payoff with 30MW of contract

Output (MW)		Generator B bids		
		Low @ cost (10$/MWh)	High ($20/MWh)	
Generator A bids	Low @ cost (10$/MWh)	50	70	A output
		50	20	B output
	High ($20/MWh)	20	40	A output
		70	40	B output

Pool prices ($/MWh)		Generator B bids		
		Low @ cost (10$/MWh)	High ($20/MWh)	
Generator A bids	Low @ cost (10$/MWh)	$13	$15	
	High ($20/MWh)	$15	$20	

Difference payments ($)		Generator B bids		
		Low @ cost (10$/MWh)	High ($20/MWh)	
Generator A bids	Low @ cost (10$/MWh)	$0	($60)	A differences
		$0	($60)	B differences
	High ($20/MWh)	($60)	($210)	A differences
		($60)	($210)	B differences

Profit ($)		Generator B bids		
		Low @ cost (10$/MWh)	High ($20/MWh)	
Generator A bids	Low @ cost (10$/MWh)	$150	$290	A profit
		$150	$40	B profit
	High ($20/MWh)	$40	$190	A profit
		$290	$190	B profit

We can make some further observations about market power in this case. There could well be a mixed strategy equilibrium in which each generator follows several different strategies with different probabilities, resulting in supra-competitive revenues. But more interestingly, we can see that there are collusive outcomes where both bidders bid high which maximizes total profits. Thus, we would expect this level of contracting to have some mitigating effect on market power, but the resultant market to be susceptible to tacit collusive behavior. This is particularly likely given the daily repeated nature of the game transacted in the pool.

Figure 5: An example of CfDs managing market power cont…

In the last example, Table T3 below, we increase the level of contract cover on each of the strategic generators to 40MW.

Table T3. Payoff with 40MW of contract cover

Output (MW)		Generator B bids: Low @ cost (10$/MWh)	Generator B bids: High ($20/MWh)	
Generator A bids	Low @ cost (10$/MWh)	50	70	A output
		50	20	B output
	High ($20/MWh)	20	40	A output
		70	40	B output

Pool prices ($/MWh)		Generator B bids: Low @ cost	Generator B bids: High
Generator A bids	Low @ cost (10$/MWh)	$13	$15
	High ($20/MWh)	$15	$20

Difference payments ($)		Generator B bids: Low @ cost (10$/MWh)	Generator B bids: High ($20/MWh)	
Generator A bids	Low @ cost (10$/MWh)	0	($80)	A differences
		0	($80)	B differences
	High ($20/MWh)	($80)	($280)	A differences
		($80)	($280)	B differences

Profit ($)		Generator B bids: Low @ cost (10$/MWh)	Generator B bids: High ($20/MWh)	
Generator A bids	Low @ cost (10$/MWh)	150	$270	A profit
		150	$20	B profit
	High ($20/MWh)	$20	$120	A profit
		$270	$120	B profit

This example has two key features. Firstly, the Nash equilibrium occurs when the strategic generators bid their marginal costs. Thus, the competitive equilibrium occurs at competitive prices. And secondly, there are no other outcomes which have higher overall profits than the competitive case, which means that *within the strategy space considered* there is no prospect of collusive outcomes. Of course, a wider strategy space with more extreme above cost bidding may change this outcome, but more extreme strategies are easier for a regulator to identify.

4.3.2 Contracts, monitoring, information disclosure and demand side responses

The foregoing shows how contracts can reduce the incentives for generators to abuse market power. But in systems that are short of capacity, such as Alberta, the quantum of contact cover needed to entirely mitigate market power is likely to be high. And as we have noted, this is likely to result in risk-averse generators with strong incentives to force down pool prices. However, there are two factors which would make more modest levels of contract cover efficacious and which, as a result, do not induce artificially low prices:

- increases in the price elasticity of demand at peak times have a profound impact on the ability of generators to abuse market power. If demand is more elastic, then generators will lose a larger proportion of their output for a given change in price because total demand will fall.[13] The single most important step to encourage effective demand side participation is to encourage the rapid development of retail competition, and to allow competitive supply across as wide a proportion of the market as possible. However, we note that changes in demand elasticity will take a number of years to occur;

- contract cover that does not mitigate market power entirely does none the less require the incumbent generators to use more exaggerated forms of behavior in order to raise their profits. That is, higher levels of contract cover then require steeper increases in bid prices by strategic players to raise profits. If effective monitoring is in place, then contracts need not be solely charged with market power mitigation. Rather, they need to be at a level that would make anti-competitive behavior obvious; and

- the most likely outcome after the imposition of contracts is that there will be multi-period Nash equilibria above the competitive price — that is, there will be tacit collusive games that raise profits. Increasing the level of contract cover will force generators into more exaggerated behavior to sustain these collusive equilibria, which aids detection. But in addition, the regulator can delay the release of key pool-related data that would help participants reach these equilibria. Extensive information disclosure regimes can hinder rather than foster competitive outcomes if they facilitate collusive games. The value of the information in supporting these games diminishes significantly if the disclosure is delayed.

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13 Alternatively, the price increase for a given restriction on generator availability will be smaller if demand is more elastic. In either case, the impact of the change in elasticity is felt most by the strategic players that adopt the high price or low availability strategy.

4.4 Allocation of generator rents

The foregoing section reviews the mechanism by which contracts reduce or remove the incentives for generators to abuse market power. This is likely to be a pivotal regulatory mechanism for some years to come. Contracts also provide a mechanism for transferring pool revenues earned by generators to final customers. For example, it is possible to calculate the two-way contract prices that are consistent with the book value of the incumbent generators assets. Pool revenue in excess of these prices would be paid by generators to customers in the form of difference payments, and the resultant final prices would be lower than the market value of the power. However, contracts may not be the most efficient mechanism for achieving this transfer. The rent transfer has some of the characteristics of a tax. Mechanisms for transacting the transfer should be evaluated on a similar basis. Hence, the key objectives should be:

- to minimize barriers to competition in both generation and retail supply;
- to minimize distortion of consumption, which means that all customers should be exposed to a *market driven* price for marginal consumption. This is best managed through a usage independent allocation mechanism; and
- to alter the amount of rent transferred in response to changes in the underlying market value of the generation assets.

Impact on competition and allocative efficiency

The allocation mechanism must not hinder the development of retail competition. Unfortunately the simplest contract form, the two-way CfD which fixes prices for a quantum of plant, also results in final prices which are below market rates. This raises two important issues:

- is this quantum of power ever at the margin for some power customers, and even if not, do smaller final customers respond to average or marginal tariffs;[14] and
- in order to support competitive retailing either customers should be able to retain their below market price quantum of energy when they switch retailer, or some mechanism is required to allocate rents to new entrants in the supply business.

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14 That is, it would be possible to structure final prices as a two-part tariff with a lower rate for the first tranche of consumption and a higher tariff for consumption above that threshold. The impact of such tariffs on allocative efficiency depends upon how customers interpret their power bills.

Neither option is particularly attractive. The former runs the considerable risk that participants will not face the market price for energy. The latter will require complex settlement and switching arrangements to support competition.

We also anticipate that the level of contract cover needed to mitigate market power but also to foster an efficient pool is below the expected energy sales from the incumbent generator plant. As a result, if these contracts are used to transfer generation rent, they will have to be priced below the price that would yield the book value of the assets. For example, if the market price is $30/MWh and the average cost given book value is $25/MWh, the contract price would need to be $25/MWh under a 100% cover regimen, but nearer to $20/MWh at 50% cover.

Contract strike prices for generators whose book value is significantly below book value would require strike prices at or below the generator's marginal cost. This may well give generators incentives to bid their contract strike price rather than their true variable costs and is therefore likely to result in both allocatively and productively inefficient outcomes.

4.4.1 Contract indexation

Contracts primarily designed to transfer rent from sellers to buyers must adapt to a changing differential between market value and book value. Pool prices minus short-run operating costs represent market value; pool prices are exogenously determined, but a generator’s own costs are determined by fuel and other operating costs. Contracts that lock in estimates of these costs either:

- reduce incentives for the generators to improve operating efficiency or fuel purchasing practices; and/or
- pass all the gains from improvement to the shareholder.

Ideally, one would want to index the rent transfer contracts to reflect underlying fuel costs and improvements in operating efficiency, and in so doing allow an equitable sharing of gains between shareholders and customers. Contracts of this type are difficult to design; they usually take the form of an underlying fuel price index, a CPI-X component to deal with operating cost efficiency and a periodic review.

In summary, the indexation provisions for rent transfer contracts should focus on generator costs. This is different from the indexation procedures that would be required for contracts designed to mitigate market power. The efficacy of a contract to manage market power depends upon:

- the difference between the strike price and market price; and
- the quantity of contracts in place.

The efficacy of the market power mitigation contract is related to the ratio of the strike price of the contract and the prevailing pool price. For example, a significant change in underlying competitive pool prices would increase the relative contribution to revenues from the pool sales and regulatory contracts. An increase in market prices would make the mitigation contracts less effective, a decrease would make them more effective. Thus, real increases in gas prices or generation capital costs would tend to increase incumbent market power for a given level of contract cover. Furthermore the efficacy of the contracts changes significantly with increased demand-side participation (i.e. higher price elasticity of demand) and with changes in underlying market share of the generation market. Thus, to avoid changing the balance of market power, one would want to index market power mitigation contracts as follows:

- index the strike price by reference to indices that impact marginal generators in the pool rather than infra-marginal generators; and
- trigger changes in either the quantity or strike price of the contracts in response to changes in market share or changes in demand side responsiveness.

4.5 Separation of market power and rent transfer instruments

The rent transfer and market power mitigation functions are very difficult to achieve with a single financial instrument. At best, if a single instrument is selected, it would need frequent review and adjustment, which would amount to an unwarranted level of intrusion into the operation of a market which, it is hoped, will be competitive. At worst it will result in neither objective being satisfied. We would expect better outcomes if the two sets of objectives were handled separately, such that:

- generators would have incentives to trade in the market in order to earn market prices, which would require that contract strike prices are consistent with the expected competitive wholesale market prices (which we discuss in the following section); and
- rents are transferred from generators to customers in the form of fixed payments that are generally independent of *short-term* pool prices.

Rent transfers in the form of fixed payments have a number of significant advantages over the alternative which can be broadly described as allocation of a quantum of below market price power. Firstly, the fixed charges do not change the short-term incentives on incumbent generators in the pool. They may affect longer-term behavior in the pool, depending upon the way in which the fixed charges are determined.

Secondly, the fixed payments are easier to allocate across final customers in a manner which does not distort consumption. The fixed payments can be used to offset distribution and transmission charges rather than energy charges. This has a number of attractive properties:

- transmission and distribution networks are natural monopolies, so customers cannot choose a competing service. Hence, allocation of the rents to wires charges ensures that a competitive retail sector can develop based on market driven energy prices without the need for complex contract allocation mechanisms or complex settlement procedures;

- there would be no additional complexities associated with new entry into retailing;

- all customers would face market prices for their energy, fostering allocative efficiency and improving the prospects of demand side responsiveness; and

- it would have equity benefits in that it would reduce fixed charges for service, tending to reduce the *average* energy bills for low volume consumers (in which low income households and small businesses tend to be over-represented).

Review of the fixed payments

It is unrealistic to expect to be able to predict *ex ante* what the payments should be, given the uncertainty over future market outcome, whether that prediction were to take the form of a fixed schedule of payments or payments based on some form of indexed contracts. The transfers will need some form of period review. We would suggest the following guidelines:

- independent determination of the difference between market value and book value based on a number of indicators, not simply historic pool prices. For example, an independent review should also consider primary fuel prices, changes in underlying new entrant capital cost, possible changes in demand side participation and, of course, prices that prevail in the pool and in the unregulated contract market. Reliance solely on the pool and unregulated contract market gives incumbents incentives to manipulate prices in order to manipulate the amount of rent transferred to customers;

- review at 2 to 3 year intervals rather than annual review, particularly if the transfers are transacted as lump sum payments. This further reduces the risk that incumbent generators will seek to manipulate pool prices to influence the outcome of the review; and

- prior to review, establishing through consensus rules for allocating efficiency gains (or losses) between customers and shareholders, such that generators have incentives for productive efficiency.

4.6 Options for market power mitigation contracts

This section reviews the various features which should be considered in designing effective market power mitigation contracts for differences. The key considerations are:

- contract term;
- form — one-way or two-way;
- pricing;
- the overall level of contract cover;
- contract counter-party; and
- mechanisms for adjusting contracts in response to changes in market events.

Contract term

The Alberta power market is highly concentrated and short of capacity. While growth is currently rapid, it will take many years for new entrants to reduce concentration sufficiently to mitigate market power concerns, even if the incumbents stay at their current size. Hence, the contracts need to be in place for a similarly long period. We would suggest an initial contract term of between 10 and 15 years with an option or review mechanism for extending the term in 5 year increments. We would only recommend a shorter initial term if there is clear evidence that the market will become markedly less concentrated over the next 10 years. The initial entry analysis presented in a later section shows that over a five year period the expected market power of incumbents will remain very high.

Form

The contracts could be one-way, two-way or a combination of both. From a market power perspective both contract forms reduce the profits that incumbent generators can earn from raising pool prices. However they have dramatically different properties if pool price is below the strike price; under a two-way contract the generator always receives the strike price, under a one-way contract the generator receives the lower of strike price and pool price.

We can compare the incentive properties of two contracts — a two-way contract whose strike price is set to the expected competitive wholesale price, and a one-way contract with the same strike price, but no option fee.[15] Both contracts remove any rent from increasing pool prices

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[15] There would be no option fee associated with the one-way contract because the contract caps the generator's revenue at what is deemed to be an appropriate market price. If an option fee were also levied it would imply that revenues could rise *above* the market price.

above the expected market price. However, if the generators chooses to reduce prices below the competitive price (perhaps in order to deter entry[16]) then the two-way contract decreases the cost of that strategy because the customer ends up paying difference payments to the generator to cover the difference. This is illustrated in Table 1, which shows the revenues a 100MW generator would earn when covered with either a one-way or two-way contract. Revenues are identical when pool prices are above the strike price, but are lower for a one-way contract when pool prices are below the strike price. Thus, a one way-contract increases the cost to an incumbent generator of lowering pool prices relative to a two-way contract, and is more likely to deter predatory types of behavior.

Table 1. Performance of one-way and two-way contracts

	One-way contract	Two-way contract
Generator capacity (MW)	100	100
Contract cover (MW)	50	50
Expected competive price ($/MWh	$30	$30
Contract strike price ($/MWh)	$30	$30
Revenues at $35/MWh pool price	$3,250	$3,250
Revenues at $25/MWh pool price	$2,500	$2,750

On first examination it would appear that the one-way contract has clear advantages in that it prevents both anti-competitive price falls and increases. However, it is also highly risky. The one-way contract gives the generators incentives to peg the pool price at the one-way contract price. Thus, if the actual competitive price is lower than the estimated competitive price, which is highly likely, then the one-way contract results in inefficient pool prices, and may even foster inefficient entry. Reducing the one-way contract strike price decreases the likelihood of this adverse outcome, but reduces the contract's efficacy against predation. This would tend to suggest that a composite strategy may be desirable, as follows:

- use two-way contracts to mitigate market power, but ensure that they are prolonged and conservative,[17] thereby ensuring that there are no long-term gains from predation; or

- use one-way contracts during peak hours where the payoff from predation is likely to be greatest, but where it is easier to define a floor price (below which there is a *prima facie* case of predation), but use two-way contracts in shoulder periods, which minimizes the problems associated with poor estimation of competitive prices.

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16 Assuming there was some foreseeable future gain from such a strategy.

17 In the sense that they err towards over-cover rather than under-cover.

Pricing

The foregoing suggests that the strike prices on the contracts for differences should be set at the estimated competitive price for the period covered by the contract. Mechanisms for updating the price in response to market changes are discussed below. The main reasons for adopting a competitive market price rule are as follows:

- there is some evidence that contracts give generators with market power incentives to set pool price at the contract strike price when the strike price is above the generators marginal cost and below expected competitive pool prices. If this occurs in Alberta, it would bias the pool price, so it is better for the bias to lead towards expected competitive prices;

- if strike prices differ from expected competitive prices, then the contracts will result in rent transfers between the generators and the counter-parties. This would significantly complicate the task of adjusting the level of contract cover in response to market changes because the changes would change the allocation of generation rents. It would also predispose complex retail settlement procedures or diminished retail competition (as discussed above). Furthermore, there would need to be some re-allocation of contracts to new retailers as they enter the market;

- one cannot avoid the issue of estimating future prices by setting an arbitrary strike price or a strike price based on generator costs. Both these price setting rules would result in transfers between generators and the counter-party, which would need to be assessed against some market price benchmark; and

- it is not clear how retailers would establish their energy rates if they received a quantum of power under contract at below market rates.

Level of cover

The level of cover is essentially an empirical question; the analysis presented in Section 5 gives an indication of some of the analytical techniques that can be used. However, it is important to note the following:

- in a tight system such as Alberta it is very difficult to remove all market power at peak times, because the loss of any one generator would result in failure to supply and prices equal to the value of unserved power. It is therefore not sensible to apply contracts at peak times that have that objective. In these hours there should be a greater emphasis on monitoring approaches and a greater tolerance of high prices which are, after all, encouraging of new entry; and

- otherwise the level of contract cover should be sculpted across hours of the day, days of the week and seasons.

We note that the Alberta pool allows separate price quantity bids in each hour of the day, which increases the scope for gaming. In effect, the generators can play entirely different games in different hours of the day because there are rigidities in the system which significantly limit substitution of supply or demand between hours of the day.[18] If generators have to submit a uniform supply curve for each hour of the day, then strategic behavior in one hour significantly reduces the strategy space for bidding into other hours. In so doing, it makes strategic behavior easier to identify and reduces the requirement for contract cover to manage market power.

Contract counter-party

The easiest system to administer would be a direct contract between the incumbent generators and the incumbent retailers. This arrangement is tenable if and only if the average purchase costs under the contract are consistent with expected competitive wholesale prices; contract prices below competitive levels give the incumbent retailers an advantage in the competitive retail market, prices above these levels place them at a disadvantage. The alternative is to make individual customers the contract counter-parties, such that a customer retains the contract entitlement if they switch between competing retailers, an option which we discuss in the previous section in the context of rent transfers.

The market is likely to be simpler and more efficient if the first of these approaches is adopted, subject to the key proviso that the contract price adjustment mechanism ensures that prices move appropriately in response to changing market conditions.

4.7 Adjustment mechanisms

Although we anticipate that contracts will be required for at least 10 years, we also recognize that significant market and technological changes can take place over that period. We have already discussed the prospect of increased demand-side participation stimulated by retail competition. But we might also expect *inter alia* changes in relative fuel prices, changes in the technological mix through new entry, and perhaps some voluntary generation divestiture. The regulatory contracts need to adapt to these market events, to the extent that market changes change underlying incumbent market power.

Price

The previous discussion of contract prices advocates setting strike prices at expected competitive prices, even though any such calculation will inevitably suffer from forecast error. But it is not possible to avoid forming these expectations of future competitive wholesale prices given the two-fold objective of managing market power and transferring the difference in value between generation asset market and book values back to customers. So any reasonable set of

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18 Which is to say that peak and off-peak hours can be considered as separate but linked (by commitment decisions) markets.

market power mitigation instruments must be underpinned by a notion of both competitive behavior and competitive price. These can be formalized in the strike price of the contracts.

The principle regulatory problem is the prospect that the market will evolve, as will competitive prices in that market. Accordingly contract strike prices will need to change in ways that cannot be predicted easily in advance. Hence, we would suggest some form of annual review or indexation. The indexation should take into account:

- prevailing pool and unregulated contract prices;
- the price of interconnected power, to the extent that it is available at the margin; and
- underlying cost indices such as prevailing fuel prices and new entry capital costs.

Level of cover

We would propose a market share trigger mechanism for adjusting the level of contract cover. There are three possible mechanisms:

- an *ex ante* determination of the level of contract cover needed for incumbent generators for a given market share. For example, initial contracts could cover 50% of peak capacity for a portfolio that owns 30% of system capacity, which could fall to, say, 25% if the portfolio market share falls below 20%. In the limit, this could trigger premature termination of the CfDs; or
- adjustment through periodic review, where the regulator is charged with adjusting the contract terms in accordance with some prescribed guidelines, which has a high level of attendant regulatory risk; or
- a compromise in which contract review is triggered by defined changes in market share.

The first of these options carries with it the lowest level of regulatory risk, but there is considerable uncertainty over the appropriate trigger levels. For example, the triggers would be different if a market comprising 4 equally sized participants and one comprising 2 large and 2 small participants. The other options carry a higher degree of regulatory risk.

We note that the process of market power mitigation is not precise, and is prone to uncertainty. As such, it require active monitoring as well as passive measures such as contracts. If the monitoring is effective, then it should be possible to define some trigger points in advance based on a combination of market concentration and market share measures which would result in manageable market power.

4.8 Auctioned bidding transfer contracts

Imposed contracts for differences seek to mitigate market power by altering the incentives on generators to manipulate pool prices and quantities. An alternative mechanism is the transfer of operational control (i.e. bidding) to a third party while allowing the incumbent generator to own and operate the plant. This mechanism has the effect on not only changing the payoff structure to the incumbent (whose prices are set under a fixed price contract to a third party) but effectively creates new competitors in the market whose interests can be divergent from that of the incumbent.

Figure 6: Bidding transfer mechanism

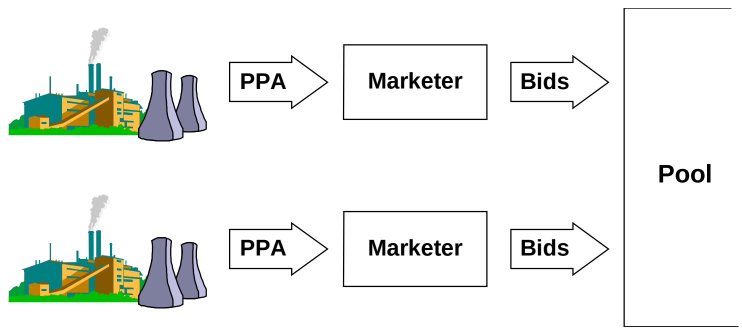
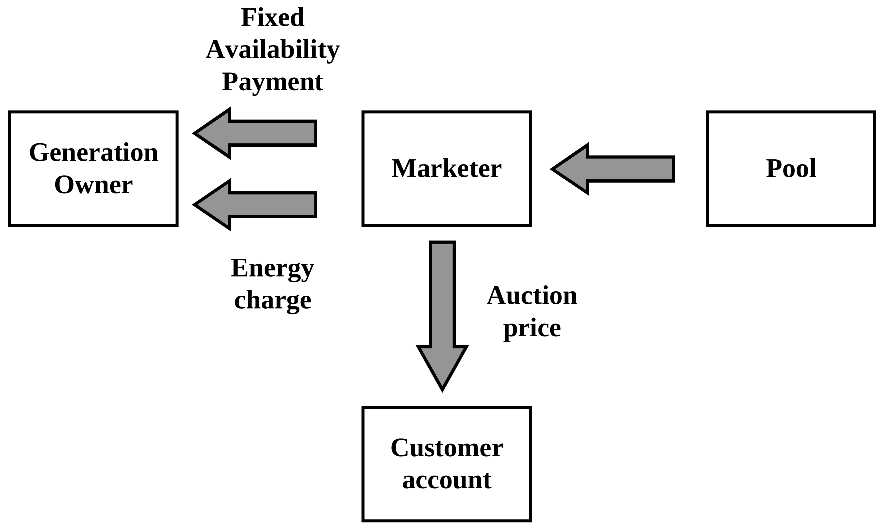


Figure 6 illustrates a potential mechanism for controlling market power through the of bidding transfer contracts. Under this arrangement the existing generator owners would auction the sale of a multi-year firm power purchase agreement (PPA) to a third-party (non-affiliate) marketer. Contract terms would be set to reflect the embedded costs of generating units currently reflected in the legislated hedges. The terms of the contract would allow the marketer to bid the plant and control dispatch, thereby creating a new competitor in the Alberta Power Pool.

The third-party marketer would buy the power from the existing asset owner at embedded cost, and be paid the pool price in each hour. The expected value of the contract over the period is thus the difference between regulated revenues and market revenues, or the expected rents to be transferred from generators to customers under the current legislated hedges. By auctioning the contracts this value is determined *ex ante* by the market. The amount paid for the contract by the marketer is therefore allocated to a customer account to accomplish the rent transfer objective. The flow of payments under this scheme is shown in Figure 7.

Figure 7: Payment flows in bidding transfer auction



This proposed mechanism has several potential advantages over other potential market power mitigation options:

- the existing utilities would continue to own and operate the units. No change of ownership would be required, and existing union or supply agreements could be easily protected;
- this mechanism accomplishes both market power mitigation and rent transfer in one step. Limited continuing regulation would be required as compared to most other mechanisms;
- the marketers purchasing the contracts would be effectively unhedged against the Pool (except for their own commercial hedging arrangements), and would be required to recover all of their fixed and variable costs from the wholesale market. This should minimize the potential for distortion of prices through generators remaining heavily contracted;
- the rent transfer amount is determined up front by the auction process, which removes the potential influence of an adjustment mechanism on generator behavior. No expert determination of future prices would be required, and the contract purchasers take the risk that their market assessment is erroneous;
- since new competitors are effectively being created in the market (as opposed to "passive" CfDs which only fix the payoff structure on existing plants, while allowing the incumbent generator to bid them normally), a lower level of plant contract cover should serve to reduce potential market power under this contract design, as compared to the imposed CfD solution; and

- recent auctions in the United States, Australia and Latin America have achieved far higher prices for generation than previously expected, often in markets considerably less attractive than the Alberta market. If high prices for the contracts were received a windfall would become available to be shared among Alberta customers and potentially the incumbent generators.

4.8.1 Contract design

The design of the power purchase agreement (PPA) between the marketer and the generation owner should have several objectives:

- produce strong incentives on generator availability, thermal efficiency and operating costs in order to maximize productive efficiency, while not exposing generation owners to undue risks. If generation owners exceed plant operating targets some upside should be retained for shareholders to give these incentives;

- allow the marketer to effectively bid the plant in the pool and manage trading risks as if he or she operated the unit, to create effective competition;

- remove all influence of higher pool prices from the generation owner, to ensure that incentives on the remainder of the generator's plants are not affected.

These objectives can be met by using a dispatchable PPA contract form where the generator is paid a fixed payment covering its fixed costs and an energy payment for every MWh it produces. This contract would consist of several elements:

- **fixed availability payments:** the generation owner would be paid fixed availability payments in every hour the unit was available. Payments could be sculpted seasonally and daily to ensure that the generator was under maximum incentive to keep the unit available in peak price periods. The sum of expected availability payments (based on target levels of maintenance requirements and forced outages) would be equal to the generator's expected fixed (embedded) costs on the unit. These would include: fixed O&M costs (staffing, spares, etc.), property and other taxes, depreciation, return on capital (at the book value of the asset - similar to the legislated hedges), and other fixed costs. Determining these costs would be closely analogous to setting the fixed payments under the legislated hedges;

- **energy payments**: the generator would be paid a variable charge for each MWh generated. This would be calculated as the fuel cost (indexed) times the target heat rate times the number of kWh actually produced. The use of a target heat rate gives the generation owner strong incentives to maintain or better the existing thermal efficiency of thermal units;

- **fuel cost indexation:** fuel costs in general could be indexed against published gas or coal indices or other agreed terms. Since much of the coal burned in Alberta is minemouth other indexation provisions could be used to reflect expected gains in productivity;

- **fixed cost indexation**; some elements of fixed costs would be adjusted from year to year by pre-determined indices such as the producer or consumer price indices. These should reflect productive efficiency improvements expected over the period;

- **pass-through costs:** some costs elements (such as local property taxes, environmental taxes, etc.) are outside the effective control of the generation unit owner. These can be passed through directly to the fixed availability payment;

- ***force majeure* conditions:** the generator would require protection against high liquidated damages arising from a major event outside its reasonable control. PPAs usually contain detailed *force majeure* conditions which limit exposures under these circumstances.[19]

- **availability penalties:** under the current Alberta Power Pool structure the marketer would not face additional liabilities to the Pool if the unit was unavailable, since there is no penalty for generators not being available as scheduled. The marketer would be penalized if he or she had entered into a firm hedging contract, however, and the unit was not available. Some additional penalty payment structure might be required to allow the marketer to enter into a reasonable contracting position without undue exposure from unit forced outages.

The marketer would retain exclusive rights to bid the plant into the Pool and instruct the utility as to its operating schedule, subject to pre-determined constraints on minimum on and off-times, ramp rates, maintenance requirements, etc.

We note that there is a substantial body of experience on the design of similar contracts in several systems. These would include the IPP contracts signed by the regional electricity companies (RECs) in England and Wales, and dispatchable qualifying facility (QF) contracts in the United States. Many of the latter are currently being sold at auction to new owners who will then bid the power into restructured competitive power markets.

4.8.2 Contract term and auction design

Depending on the exact policy objectives for the sector the contracts could extend across any range of time periods. Five years is probably a workable minimum, with seven to ten years more cost effective. Alternatively, the contracts could extend for the life of the plant.

The contract auction process could follow a standard process. Typically in these auctions a short-list of five or more bidders is selected from the list of interested parties. The latter could include utilities, IPP developers, gas suppliers or other industry participants. Since the value of coal-fired plant is likely to be strongly dependent on the price of gas in the province we would expect some interest from major gas companies. These five firms would then enter into a detailed due diligence procedure before submitting final binding bids a few months later. In

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19 The existing legislated hedges also contain *force majeure* language, in case of extended unit availability.

similar asset auctions bidders are often required to show that the bid price can be financed from cash or corporate borrowings or that financing has been arranged.

The auction process sets the level of total rent transfers up front through bid prices. However, it would not be advantageous to have the total rent transfer amount applied as an offset to customer's bills in one year. Instead, we envisage that the contract price set in the auction would be paid to customers over the length of the contract. If the marketer was allowed to pay for the contract in equal amounts over the length of the contract it would need to meet stringent credit and default risk requirements.

Since the objective of the contract auction is to curb market power a single firm would not be allowed to bid for more than a certain number of contracts. The limits could vary according to the type of plant. For example, a bidder could bid for one baseload and one peak plant but not two peak plants. Affiliates of incumbent generators would be prevented from acquiring bidding transfer contracts. The design of plant auctions in California, New England and other jurisdictions offers examples of the types of constraints which might be enacted on bidding for portfolios of plants. The market power modeling framework described in Section 5 has been used in other jurisdictions to ensure that auctioned bidding portfolios are likely to produce a competitive outcome.[20]

Another issue arising from the design of the bid transfer auction is the capturing of some residual values in the plant for customers at the end of the final auction period. This would include the value of a permitted site and any salvage value in the asset, minus environmental cleanup costs, etc. The use of a fixed-term bidding transfer contract allows this decision to be pushed back to closer to the time of plant retirement, when it will be simpler for regulators and utilities to agree on the key parameters.

4.8.3 Plants with stranded costs

Although Alberta as a whole does not have a stranded generation cost problem, individual plants could have stranded costs. In this section we consider briefly how to accommodate these circumstances in the auction bidding transfer framework, while noting that the actual stranded costs may be less than they appear presently, since we expect that market prices would rise to cover average costs under the new framework, rather than relying on substantial fixed cost recovery from the legislated hedges.

We propose three initial mechanisms for consideration in dealing with these plants:

- bundling contracts from plants with potentially stranded costs with contracts from plants where embedded costs are much less than expected market prices. The net value of the contract portfolio bundle is therefore positive and the auction could proceed as described

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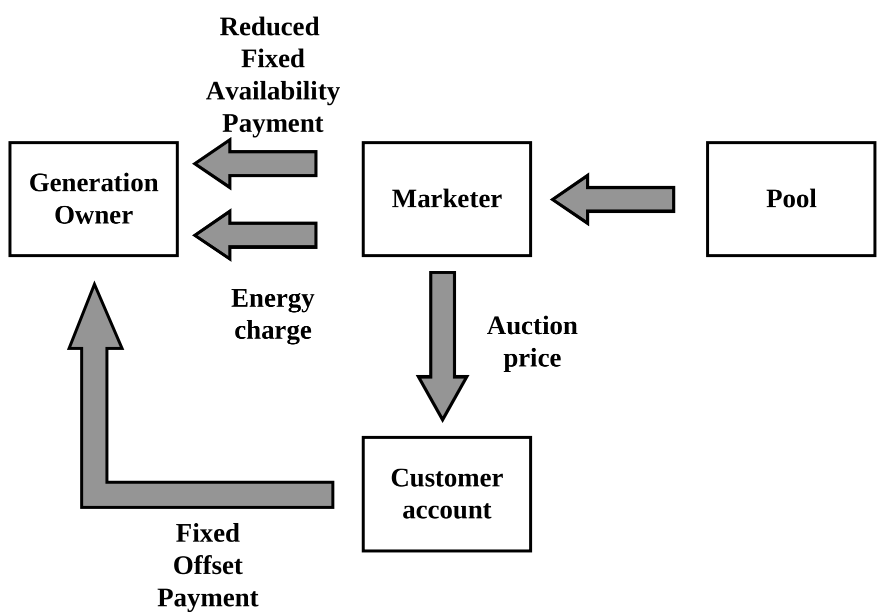
20 See for example London Economics Australia's report for the NSW Government *Does Pacific Power Have Market Power?* (1994) and LEA's report for the Queensland Department of Mines and Energy entitled *Towards a Competitive Queensland Electricity Generation Sector* (1996).

above. Careful design of contract portfolios would be required so as not to give the bundle purchaser market power, as previously noted;

- setting a fixed payment stream from the customer account to the generator. The fixed availability payment from the marketer could then be reduced, and still have the contract have a positive value at auction. This is illustrated in Figure 8. Note that the efficient transfer of rents in the scheme is not dependent on setting the customer-generator offset payment accurately. If the payment stream is too high the additional value should be captured in the contract auction and passed back to customers in that payment stream;

Figure 8: Modified payment stream for stranded asset auction



- auctioning the contract normally, with the winner being the marketer which requires the minimum fixed payment from the customer account to take over the obligation to make fixed availability payments to the asset owner.[21]

4.9 Direct bid controls

In other jurisdictions direct bid controls have been proposed for the control of market power. These may effectively cap the bids which generators can submit at a pre-determined level, or limit the bids based on prevailing prices, previous bids, etc.

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21 Auctions of "negative value" obligations are common in some fields such as telecommunications. Universal service obligations for rural customers are one example.

A full discussion of the design of these mechanisms is beyond the scope of this report. However, in the next two sub-sections we describe the basic forms of these controls and the problems attendant with their use in Alberta.

4.9.1 Bid caps

As the name suggests bid caps are simply imposed controls on bid levels. These are usually controls on maximum bids for a unit, but may also be constructed as floors where predatory behavior is a potential issue. Bid caps may be indexed against fuel prices to reduce price risk for generators.

In practice it is difficult to establish workable bid caps for peak and mid-merit plants. These plants will often set clearing prices, and the bid caps act to effectively limit peak and shoulder prices to the cap prices. This approach suffers from the level of quantity risk inherent in such plant. Pool prices must be high enough on average to return fixed costs to peak plant if generators are to make them available to the market, and generators should have an adequate opportunity to recover depreciation and return on capital. However, the load factors achievable for these units is subject to wide fluctuations, given variations in demand, new entry levels, etc. By capping prices, the generator may be at considerable risk that its peak units will never recover its going forward costs. Since these peak hours are also a major contributor to total generator margin, setting these prices will effectively alter generator returns across the broad portfolio of plant as well. To the extent possible it is advantageous to remove this level of regulatory risk from the market and rely on other mechanisms to control peak prices.

4.9.2 Price screens

The New England ISO filings propose a price screen mechanism for units which run out of merit to meet transmission constraints.[22] This trigger mechanism attempts to determine whether there are a sufficient number of plant available to allow competitive pricing (the “structural screen”) and a price screen. Payments under the latter are dependent on whether a unit runs frequently or infrequently out of merit.

As the filings note, it is difficult if not impossible to determine *ex ante* the price mark-ups which will allow these generating resources to cover their appropriate costs given the wide uncertainty in load factors for peak and even mid-merit plants.[23] While the price screen mechanisms are more workable than a straight bid cap the problem reduces to regulation for the peak and mid-merit plants and prices. If Alberta wishes to return to direct economic regulation then simpler means exist than regulation of pool prices.

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22 ISO New England, *Market Monitoring, Reporting and Market Power Mitigation* , 1997, draft.

23 Nor is it completely definable what these costs are? Should return on capital be included in the peak prices? If so, at what asset value and rate of return?

5. Modeling framework

5.1 Introduction

In this section we describe the modeling approach and assumptions used to identify whether contractual mechanisms can be effective in preventing the abuse of market power in the Alberta Power Pool by changing the payoffs to generators. We have not attempted to model in this study the effective changes in industry structure produced by the use of auctioned bidding transfers. We begin by outlining our objectives for the analysis, the system modeling tools used, and the assumptions and data sources used in the analysis.

Given the existing market structure, where three utilities control approximately 90% of the available capacity in the market, we have begun with the assumption that considerable potential market power exists within the Alberta Power Pool.

5.2 Model description

The simulation of market outcomes for the Alberta Power Pool were made with PoolMod, London Economics' proprietary power markets model. PoolMod simulates the operation of the Alberta power system and the pricing mechanisms of the Alberta Power Pool. The latter include hourly prices based on the most expensive unit run in the hour, pricing on an *ex post* basis (i.e. in real-time), and without transmission constraints. PoolMod includes:

- an hourly simulation of commitment and dispatch of the Alberta Power system, incorporating dynamic constraints on the scheduling of thermal units;[24]
- development of an annual maintenance program which balances unit availability (by type of generation) and production costs over the year;
- modeling of regional transmission constraints (not used in the Alberta model);
- shadow-pricing of storage hydro units; and
- calculation of clearing prices on *ex post* basis, reflecting the rules of the Alberta Power Pool (i.e. after simulated outages).

For analysis of bidding strategy and market power PoolMod also includes a 'game theory' module which can be used to investigate probable generator behavior under different circumstances. PoolMod calculates the payoff (defined as Pool revenues minus fuel costs) for each portfolio generator for each combination of available bid strategies. The payoffs are then

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[24] Such as the minimum on and off-times on individual units.

analyzed to compute which strategy combinations produce stable equilibria in the spot market and are therefore likely to be observed in the market.

5.3 Data sources

Data for the Alberta simulation came both from the Power Pool and from the utilities themselves. The Power Pool supplied system-wide information on demand and imports, and the utilities provided specific information on their generators.

5.3.1 System data

The Power Pool of Alberta provided hourly load data for 1993-1996, and for 1997 to date. Of the data supplied, only 1996 was complete; other years had small stretches of hours for which load was not reported. As a basis, then, we used the 1996 data for the modeling. Since the aim of the modeling is to understand the dynamic interactions between generators rather than to accurately predict prices, the fact that 1996 may not have been a very typical year is not of consequence.

Import quantities were also provided by the Power Pool, allowing more accurate modeling of power imports as price-setting virtual generators, which is how they are treated in the Pool. This consisted of hourly quantities and prices from each of several virtual units for Powerex, Saskatchewan Power, and the City of Medicine Hat.

5.3.2 Thermal generator data

Each of the three utilities provided us with detailed information on their thermal generating plant. This included capacity, minimum level of stable generation, incremental heat rate, spin no-load heat rate, energy consumption during start, and the minimum on and off times for each plant.

In addition, gas-fired plant reported an addend to the AECO-C price to account for transportation costs to each plant. Coal plant reported a complete delivered cost of coal. In cases of plants whose start fuel is different from its primary fuel, the contracted price of this fuel is also given; typically, it is gas purchased under contract rather than at spot.

The AECO-C gas price used to sculpt the seasonal variation of generation cost comes from the Price Waterhouse index for the twelve months of October 1996 to November 1997.

5.3.3 Hydro generator data

TransAlta reported average monthly output for each of their hydro plants, as well as the maximum capacity of each plant, and size of reservoir for storage. As hydro is a relatively small part of the installed capacity of the Alberta system, we did not undertake a detailed analysis of hydro generation. Hence, only limited information on typical energy output was required, as this will help determine the balance of energy that will be met by thermal generators.

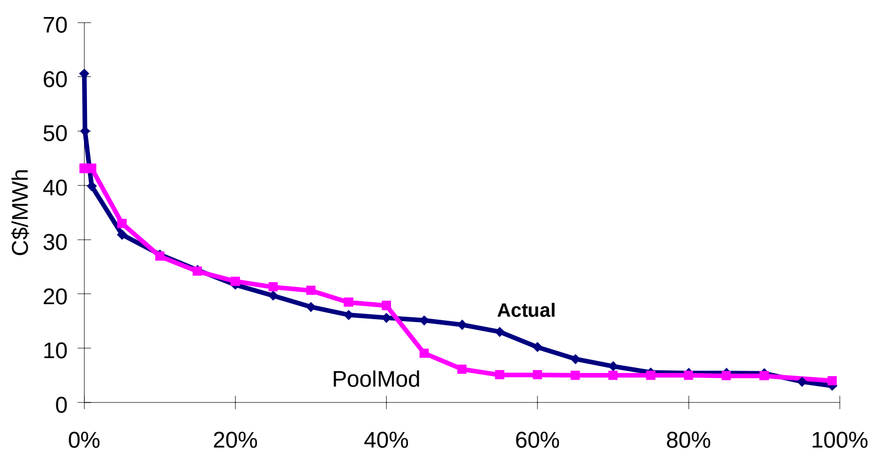
5.4 Verification of modeling

Originally developed for modeling of the England and Wales pool, PoolMod is a flexible model which can be substantially modified and applied to various systems. PoolMod also has been successfully used to simulate power markets in Victoria, Colombia, California and New England.

The present work does not call for price forecasts or output predictions, which would be based on multi-year runs of the model. Rather, we require the ability to run specific days of the year under a variety of different bidding strategies. Nevertheless, we attempted to simulate a year of operation of the Alberta Pool and compare it to actual outcomes, both as a way of testing the model and to familiarize ourselves with the operation of the market.

We simulated operation of the Power Pool for the year 1996, for which we have a complete hourly demand history. Bidding was limited to marginal cost bids, with estimates of start-up costs built into the bids. The results are shown in Figure 9, which compares the PoolMod results with those of the actual Pool.

Figure 9: Comparison of 1996 Pool prices and model prices



The model is capable of capturing the appropriate price levels for most hours, and the relevant details of dispatch. There is a group of hours where PoolMod underestimated the system marginal price. Whilst it is possible to speculate on why this occurs - above cost bidding, increased outages in those hours, for example - this verification exercise indicates that the PoolMod model adequately simulates the operation of the Alberta power system.

6. Modeling results

This section presents the initial results of the modeling analysis. We begin by reviewing the shape of the supply curve, which determines the nature of the bidding strategies which may be employed in the Alberta market.

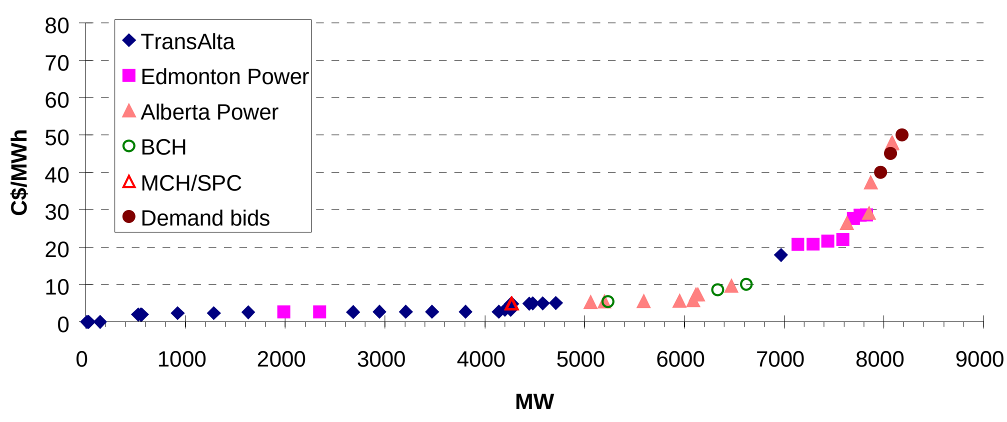
6.1 Bidding strategies and the supply curve

As an illustration of potential bidding strategies we present in Figure 10 a supply curve for the Alberta system on a normal medium demand day. The vertical axis of the supply curve was constructed from the commitment prices calculated by PoolMod for the day. The commitment price includes:

- incremental fuel costs, calculated as incremental heat rates times the projected fuel cost for the relevant period (gas prices are assumed to follow monthly trends across the year);
- no load heat costs; and
- start costs, for units which start on the day, divided by the expected number of hours of operation on the day.

Imports were treated in this example as shadow pricing against the relevant load factor plant on the day, based on historical quantity bid data. These are shown as "BCH" on the graphs, although all imports may not be from the BC system.

Figure 10: Supply curve for medium demand day



The supply curve shown in Figure 10 shows a number of features which directly affect what types of bidding strategies might be profitable for generators in the absence of mitigation controls. Again, it is to be emphasized that this initial analysis is *prospective*, based on a future-looking analysis assuming the removal of all controls, rather than on analysis of historical bids. These features include the:

- **overall low reserve margin:** to our knowledge the Alberta Power Pool is the tightest competitive power market in the world. At peak periods the potential market power of two if not three of the main generators is absolute - i.e. demand cannot be met without committing their units. A credible withholding strategy by these generators could push peak prices on peak days to the level where a high demand response was stimulated. These would be very high prices over the short-term;

- **concentration of ownership across market segments:** not only is the Alberta power market concentrated in overall capacity, but the three main generators neatly divide up much of the supply curve. As competition in the Pool is always at the margin, the baseload TransAlta plant do not compete with the EP peakers at all, for example. For various slices of the load duration curve the market structure can be characterized as near monopoly;

- **differential between coal and gas dispatch prices:** there is large differential between the direct fuel costs of coal and gas-fired generation in the province. If demand is sufficient in the Pool to force the cheapest gas-fired unit to be dispatched then Pool prices rises sharply. This gives strong incentives for TransAlta and Alberta Power to withhold coal-fired capacity across a range of days to bring the gas-fired units on, and allows Alberta Power to shadow-price its higher cost coal-fired units against the Edmonton Power gas-fired units without losing output;

- **TransAlta baseload portfolio:** TAU dominates the baseload segment of the load duration curve. This effectively allows TAU to bid costs across a range of days, although this does not apply that TAU would not have significant market power in an unconstrained market. TAU can potentially raise prices on most or not all days by withholding capacity if it were to prove necessary to do so. Given the existing market structure we would expect TAU to withhold capacity minimally in order to maximize output as long as other strategic players kept Pool prices high.

- **Edmonton Power peak-baseload portfolio:** EP controls much of the marginal plant in peak hours at Clover Bar. As discussed previously, losing output at peak to raise prices is generally profitable only if other units under the same ownership are not at risk of losing output. If uncontracted, the Genesee plant is able to benefit from higher prices even if Clover Bar loses output from raising prices, making peak pricing strategies profitable for EP;[25]

- **Alberta Power mid-merit portfolio:** APL controls a large fraction of the marginal plant across a broad range of days. The level of potential imports from British Columbia, which is limited to 400 MW by transmission constraints, is small in comparison. Even if imports were fully non-strategic it is not clear that the quantity trade-off from imports would be sufficient to prevent APL's over 1500 MW of coal units from shadow-pricing against the EP gas plants; and

- **low level of demand-side bids:** Typical total bid price responsive demand in Alberta is less than 200 MW. This would appear to be far below the amount which an incumbent generator could withhold to profitably push prices, and indeed is probably below natural demand variation on peak days;

6.2 Removal of all controls

In this section we present the results of our analysis assuming the legislated hedges were removed and no replacement mechanism was substituted for control of market power. As previously discussed, the structure of the generation market in this case is such that a high degree of market power may be exercised given the likely elasticity of demand with respect to price.

Our initial assumptions on the likely outcomes from removal of the legislated hedges were confirmed by the PoolMod analysis. Figure 11 shows the supply curve, with maximum and minimum demand shown for the test day shown by the dashed vertical lines. Note that almost every unit committed on this day, except for the baseload units which are withheld by TransAlta under their dominant bidding strategy. This extends the market power of the peak and mid-merit generators, by allowing them to bid up without losing output.

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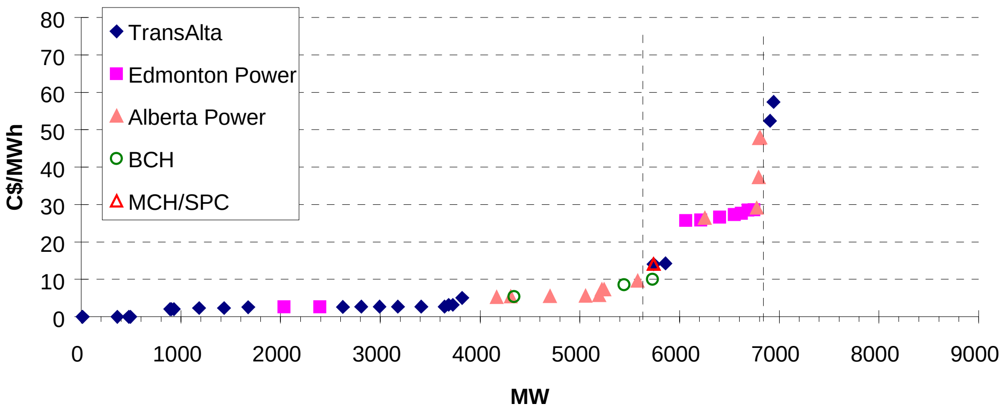
25 Clover Bar could lose output in the Pool due to competition with the Alberta Power peak plant or through demand-side bids lowering the total energy required in peak hours. Neither mechanism would appear especially effective at present as the size of both the demand-side bids and the AP peakers are small relative to variations in demand.

Figure 11: Supply curve with no contract cover - medium demand day



This combination of bidding strategies produces the clearing price curve shown in Figure 12. On the medium demand day the EP gas plant will not bid above the demand side response, limiting hourly prices to approximately $50/MWh. On the peak day the level of demand side bids can be easily exceeded, and prices can effectively rise to the value of lost load. The peak block prices of approximately $70/MWh are not in fact an effective cap but are reflective of the maximum bidding assumptions input to the model, to keep the maximum prices available on the same scale.[26]

The clear outcome of this analysis is that without the legislated hedges the strategic generators can raise prices to almost any level on peak days, by withholding capacity and bidding up peak units. The supply curve for the peak hours on a maximum day, showing high levels of withholding and bidding up, is presented in Figure 13.

26 This analysis is based on 150 MW of demand side price responsiveness, which is consistent with current conditions.

Figure 12: Clearing prices with no contract cover - peak and medium demand days

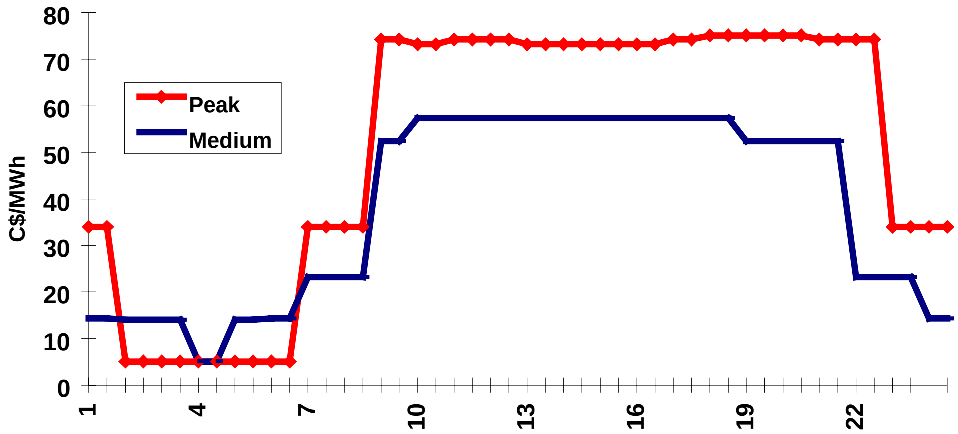
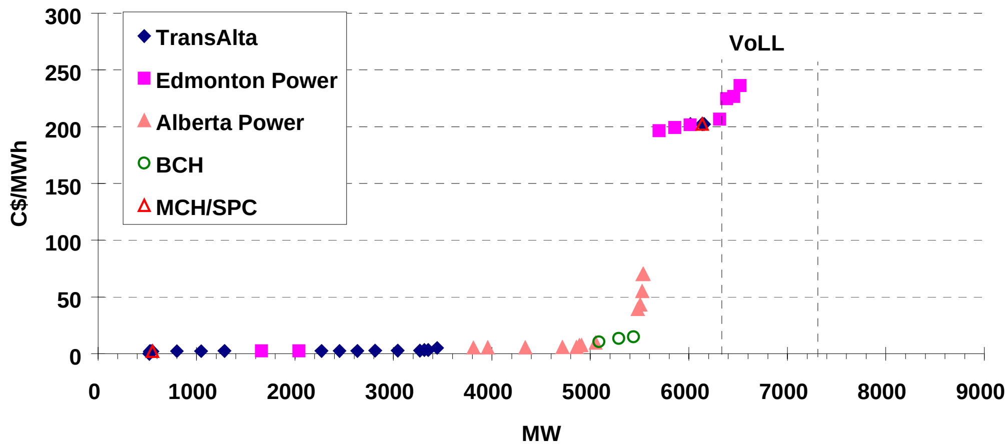


Figure 13: Supply curve for peak hours on peak demand day - no contracts



In the next three sections we investigate the potential for limiting this behavior by:

- increasing the quantity of price responsive load in the market;
- the bidding behavior of new entrants in the market at some future date; and
- imposing contract portfolios on generators.

6.3 Increased demand response

The existing level of demand response in Alberta is weak compared to the size of the market, typically less than 150-200 MW in a system with peak demand over 7,000 MW. We hypothesize this is due to:

- the structure of retail tariffs in the province. As the distributors have in general been covered against Pool purchase prices by the legislated hedges there has not been a strong incentive to introduce interruptible tariffs or Pool price pass-through tariffs, which has occurred in other competitive markets;

- the low levels of industrial load buying directly from the Pool; and

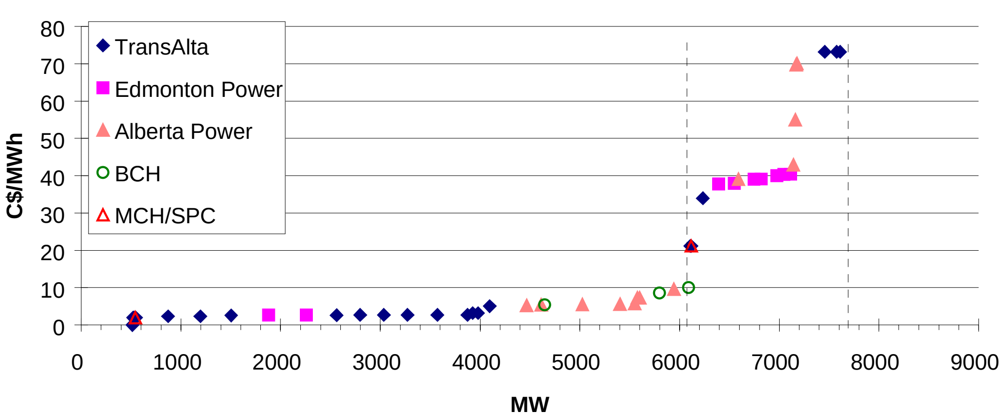
- the relatively low levels and volatility of Pool prices experienced until recently.

An important question posed in the course of this project was: can an increased demand-side responsiveness to prices help mitigate market power? To address this issue we have simulated equilibrium bidding strategies using different levels of demand side bids: 0 MW, 500 MW and 900 MW.

6.3.1 No demand response

In the case of the top hours for the peak day all of the peak units can bid up to raise prices, especially if TAU withholds some capacity. Prices rise to the value of lost load quickly across a large number of hours.

Figure 14: Bid supply curve - uncontracted 0 MW demand bids



6.3.2 Demand response - 500 MW

The introduction of 500 MW of price responsive load changes the optimal bidding strategies somewhat, although there is still clear market power, and prices can rise to the value of lost load in certain hours. In this case:

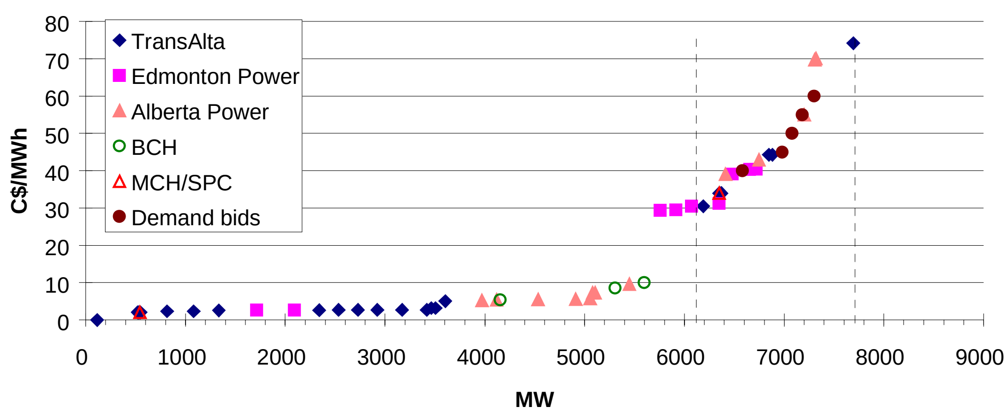
- TransAlta could withdraw some capacity to push demand in the peak hours above the highest demand side bids (unless the demand bids were themselves very high). This ensures that off-peak prices are set by the gas plant and peak prices rise to the value of lost load;

- Edmonton Power's gas plant and APL's small peaking units can shadow price against the demand bids for much of the day. This produce the prices around $50/MWh for much of the day (see Figure 17); and

- the remainder of TAU's coal units, the imports and APL's coal units maximize output at the high price.

The supply curve for this set of bidding strategies is shown in Figure 15. The vertical dashed lines represent minimum and maximum demand on this peak day.

Figure 15: Bid supply curve - uncontracted 500 MW demand bids

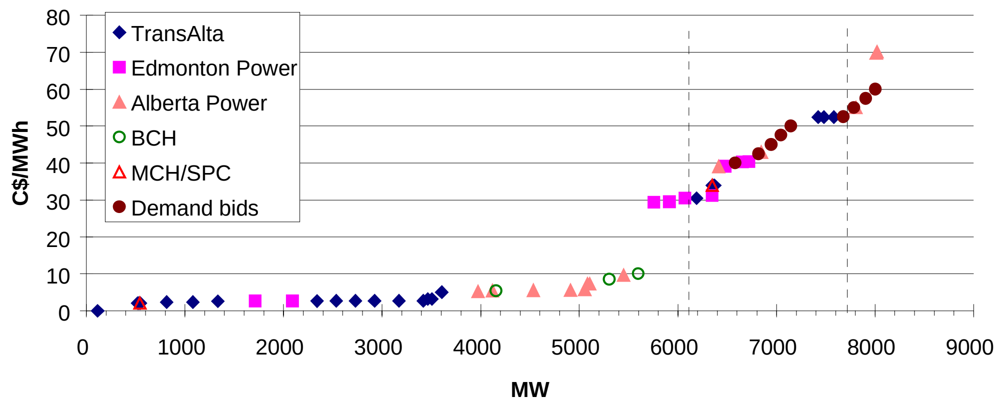


6.3.3 Demand response - 900 MW

Figure 16 shows a peak hours supply curve for the same demand day, with 900 MW total of demand bids between a price of $40/MWh to $60/MWh. Maximum and minimum demand on the day is shown by the vertical dashed lines. Under these assumptions the peak prices are set by the relatively low-priced demand bids. In this example it is not profitable for TAU or the other utilities to withdraw enough capacity to continue pushing prices up. This conclusion may not be robust against all supply conditions, or if demand growth and variation was higher than expected.[27]

The shape of the peak "supply curve" (which includes a representation of demand effects) is crucial. The shape of the right-hand portion of the curve in Figure 16 shows that the lost output for a unit raising its bid at peak is much higher than in Figure 14.

Figure 16: Bid supply curve - uncontracted 900 MW demand bids



6.3.4 Pricing outcomes

The effects on prices from high levels of demand side bids is to reduce the market power at peak, as shown in Figure 17. This example shows pricing at the system peak day. Note that the peak prices under the 0 MW and 500 MW are not truly effectively capped, and could rise beyond the $80/MWh level. The peak price shown is a reflection of the bid strategies allowed in the model and the pricing of demand side bids rather than a constraining equilibrium on prices.

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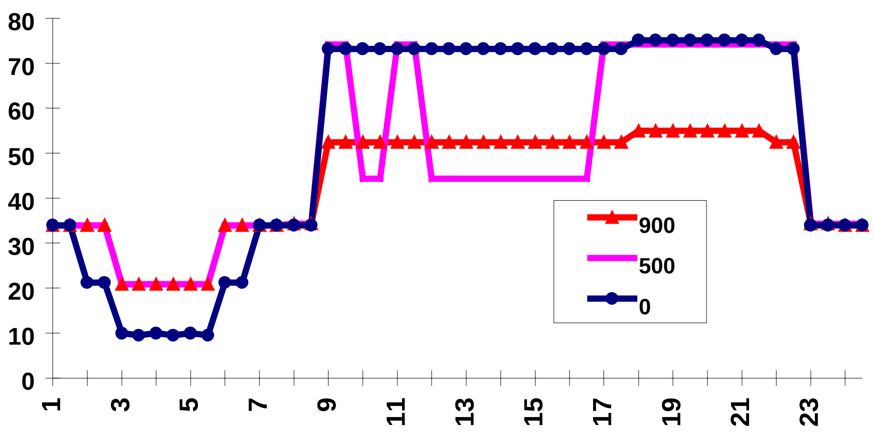
27 The supply curve shown assumes an average level of plant unavailability, spread across the portfolio of units, and with maintenance at minimum levels for a winter weekday. A higher level of outages among flexible plant would probably allow prices to rise sharply.

Figure 17: Clearing prices for different levels of demand response - no contract cover



Note that the off-peak prices overnight are actually lower for the lowest demand response case. This reflects full commitment by TransAlta of its baseload coal plants, which pushes down off-peak prices. In this equilibrium TAU does not withhold capacity at baseload as the other generators will push up prices to a maximal level anyway in the absence of demand-side bids. TAU is therefore free to maximize output without an effect on clearing prices at peak. In the 500 MW and 900 MW cases TAU withholds some level of capacity to drive up peak prices on the day, forcing the commitment of the highest cost EP and APL plants (bid well above cost).

6.3.5 Demand response - conclusions

An effective demand side response is essential for improving the pricing performance in the Alberta Power Pool. In an *ex post* market design with no capacity payment, generators must be able to bid above their variable costs at periods of inelastic supply in order to cover their fixed costs. This need not imply the existence of severe market power if there are adequate number of demand bids which constrain the ability of peak generators to raise prices with no loss of output.

From the above and other analysis we conclude initially that a much higher level of demand side response will be required to achieve an efficient peak outcome, even with the use of other market power mitigation controls. However, we conclude that a very high level of demand response (minimum of 900 MW) would be required to solve the peak market power problem in the Alberta market. Even if demand bids effectively capped the peak prices the APL coal units can profitably shadow price against the gas plants in most circumstances.

In summary, increasing the effectiveness of the demand side to responding to high prices is a necessary but *not* a sufficient condition for controlling market power. While an incentive-based mechanism will probably not work without it, it cannot be relied upon to solve the existing policy problem on its own.

6.4 New entry

The original blueprint for competition in the Province indicates that the system would grow away from its concentrated market structure as entry occurred and demand grew. The objective of our forward-looking analysis is to determine if an expected level of entry might be sufficient to dilute the market power of incumbents over time.

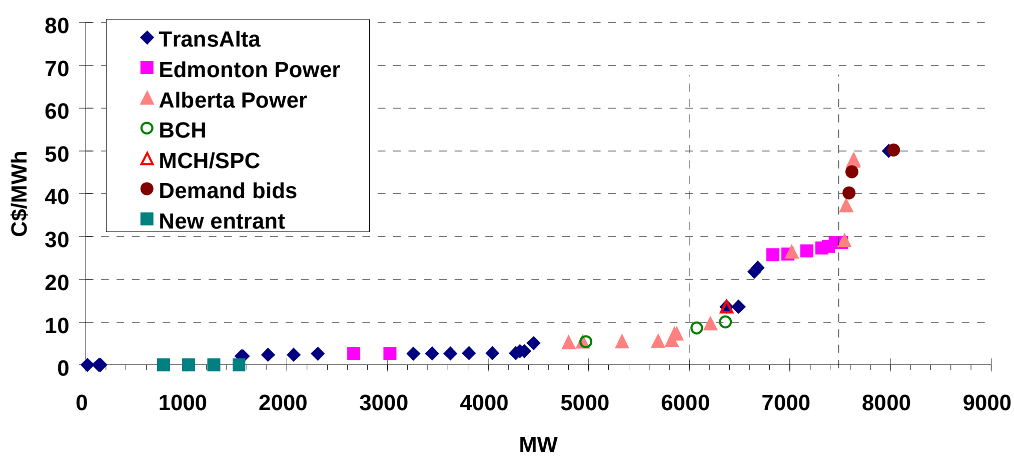
We have modeled bidding outcomes assuming 1000 MW of new entry, using a projected set of demand curves for 2003. These were based on 1996 demand shapes, scaled up by 1.8% per year on average. This adds approximately 1000 MW of new load over the current peak demand.

Two potential entrant strategies have been modeled. For simplicity, we have set all new entry to be either baseload must-run cogen (bidding zero and taking pool price) or gas-fired combined cycle plant, operating at a heat rate of 6800 mmbtu/KWh and projected gas prices.

6.4.1 Cogeneration entry

Entry by must-run cogen plant is not especially effective at changing incumbent bidding behavior. It effectively shifts the demand curve to the right, as shown in Figure 18. On a medium demand day APL and EP still dominate the marginal plant, and have substantial infra-marginal units available to benefit from higher prices. As one would expect the pricing outcome is still non-competitive, with the EP gas plant shadowing the demand side bids. Prices in the middle of the day average over $50/MWh.

Figure 18: Cogeneration entry in 2003 (1000 MW)

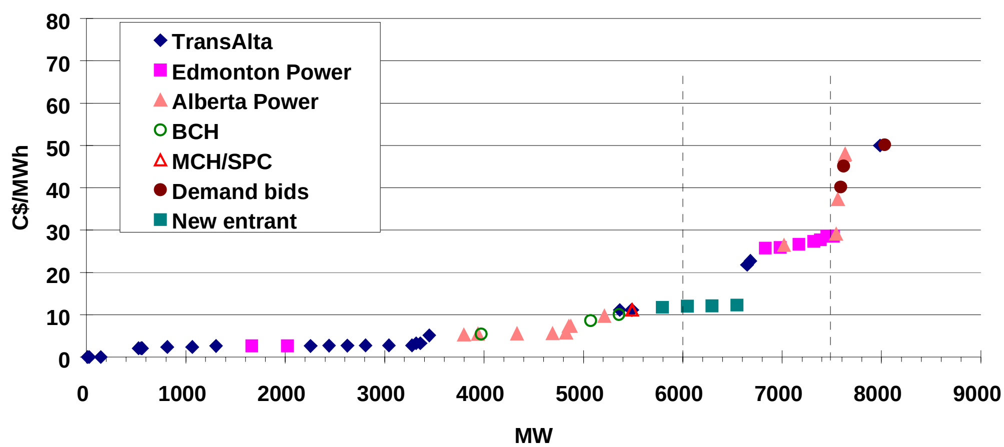


While this entry amount somewhat limits the ability of TransAlta to benefit from withholding capacity the expected equilibria outcomes are not competitive.

6.4.2 Combined cycle entry

Entry by dispatchable combined cycle plant produces a different type of outcome. The dispatch cost of the new units lies between the most expensive of the Alberta Power coal units and the fuel costs of EP's Clover Bar station. The new entrants therefore bisect the "step function" change in the supply function described in a previous section. The supply curve on a medium demand day is shown in Figure 19. Note that the competitive bids offered by the 4 x 250 MW CCGT plant (which are assumed to be independently owned) cap the bids which can be offered by Alberta Power's coal units and the imports.

Figure 19: New CCGT entry in 2003 (1000 MW)



Under the existing level of demand side bids (150 MW) the EP peak plants can still bid up, and raise prices to very high levels. On peak days the situation is much worse and market power is again unconstrained.

In general, a far higher level of entry will be required to control market power, the absence of another mechanism. Entry of 1000 MW of new plant is barely sufficient to match expected load growth, so at peak generators can continue to profit from raising prices. Further analysis would be required to determine what level of entry would be required to cap Pool prices.

6.5 Imposed contract cover

There is no direct methodology for calculating necessary contract cover for preventing the abuse of market power. We began with an initial cover of 50% on all three main generators, tested the outcomes against various types of games, and modified the level of contract cover as necessary to prevent these games.

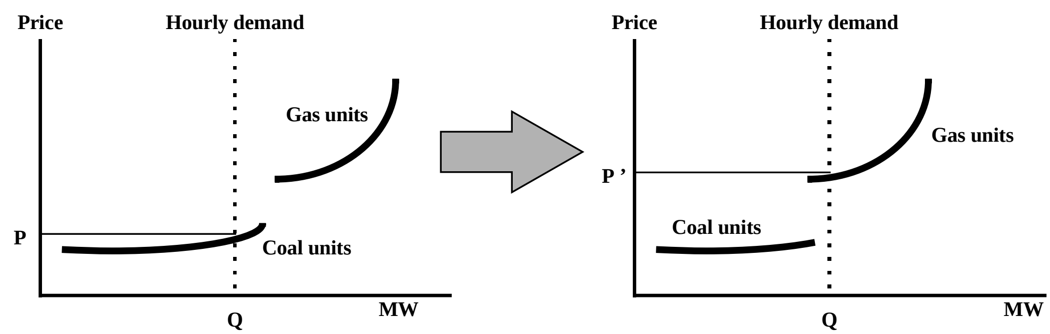
It should be emphasized that this is a preliminary analysis and that the results would require considerable further testing before developing a specific contract portfolio. Our intention is to develop a policy framework for future implementation, rather than a detailed mechanism.

6.5.1 Types of games

The number of bidding strategies which can be applied in the Alberta Pool is very large. We have focused on modeling two main types of strategies. These are:

- **withholding capacity:** a portfolio generator with sufficient market power and a diverse set of generating units can raise prices by withdrawing some infra-marginal units to force more expensive units to run. The large "step function" in the Alberta supply curve makes this a profitable strategy across a broad range of days - if some coal or hydro capacity is withheld the more expensive gas plant must be committed. For example, in Figure 20 by withdrawing baseload coal capacity a generator can force more expensive gas-fired units to be committed in an hour where they would otherwise not be needed, even if demand Q in the hour does not change. This raises the hourly clearing price from P to P' in the diagram. The step function in the costs between the most expensive coal-fired unit and the least expensive gas-fired unit makes this strategy likely to be profitable in the absence of significant contract cover on the baseload plant;

Figure 20: "Step function" supply curve



- **raising prices of marginal units:** As discussed in a previous section, this strategy can be successful only if the combined supply curve is inelastic, or if the increased prices also accrue to a infra-marginal plant. To prevent the total output of a unit from being lost generators will often bid in the final blocks of capacity at a high price, while keeping the lower blocks at cost to ensure the unit remains with some output, as shown in Figure 21.[28]

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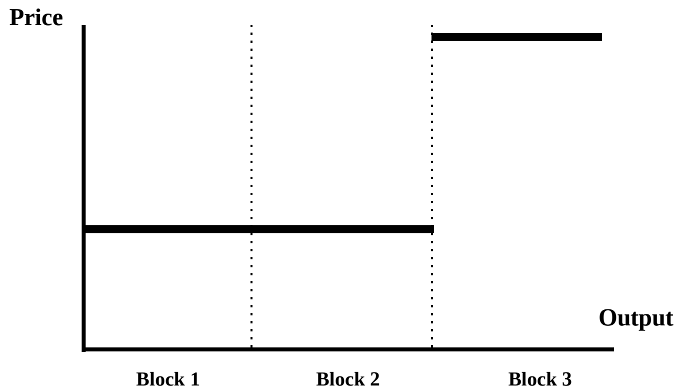
[28] For simplicity the diagram only shows three price-quantity blocks instead of the seven allowed in the Alberta Power Pool auction mechanism.

Figure 21: Final block bidding strategy



Many other types of games are possible, but have not been modeled or analyzed. These include:

- **export quantities:** generators can effectively manipulate demand by submitting demand bids for exports at key hours. The power is then wheeled out of the system in an attempt to raise prices. The payoff structure of this game is similar to withholding baseload capacity, and linked to the relative prices in the Alberta Power Pool and neighboring bulk power markets (i.e. British Columbia and the US Pacific Northwest). For example, an Alberta generator scheduling "strategic" exports to raise prices by increasing effective demand would lose an amount proportional to the difference between Alberta and BC or NW prices for each MWh sold. This strategy is only credible if the increased profits flowing to the utility's generation in Alberta more than outweighs this loss. At peak periods, given the steep shape of the effective supply curve in the Alberta Power Pool, this strategy probably will increase net generator profits. We have not attempted to model this game (as we are not modeling prices in adjacent markets), but note that simple control mechanisms are available for blunting this strategy;[29]

- **tying up transmission capacity:** our understanding is that generators can schedule imports over the tie line from British Columbia up to a month in advance. There is a clear potential for gaming this process without a "use or release" arrangement in the transmission tariff. While we have not explored import games in detail under the current market structure the efficiency of the Pool is clearly dependent on having multiple importers as competitors at mid-merit;

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29 The simplest approach would be to prevent generator marketing affiliates from scheduling exports. Other marketers would not be so constrained. Other approaches are possible but have not been analyzed in any detail.

- **collusive outcomes:** we have attempted to model only one-shot games. Effective collusion is however possible and likely under the current market structure. An imposed contract portfolio or other market power mitigation strategy should help to make collusion less likely and easier to detect. We discuss the regulatory implication of mitigation options in a later section.

6.5.2 Contract cover on all generators

The beginning point of our analysis was imposing a total of 50% contract cover on all the major generators. This set of contracts was tested against a broad assortment of demand days. These modeling runs include 150 MW of price responsive load.

Figure 22 shows a supply curve based on PoolMod commitment prices for the medium day, based on the dominant Nash equilibrium strategies of the strategic bidders. Note that the commit prices shown are based on the initial blocks of each unit. In these simulations a final block bidding strategy generally was most profitable for the major strategic players and has therefore been employed in our simulations. Use of flat price bids across the blocks would tend to understate actual market power.

In this scenario withholding capacity is a dominant strategy for TransAlta.[30] As shown in Figure 22 this forces more expensive gas-fired plants to be dispatched across much of the day, raising prices to the top of the "step function". The payoff to TAU outweighs the lost revenues from the additional output. The use of a withholding strategy is not only allocatively but also productively inefficient - demand is not met at least cost. The payoff to Alberta Power in withholding its more expensive coal capacity is negative in this game, as it has a far smaller amount of infra-marginal plant.

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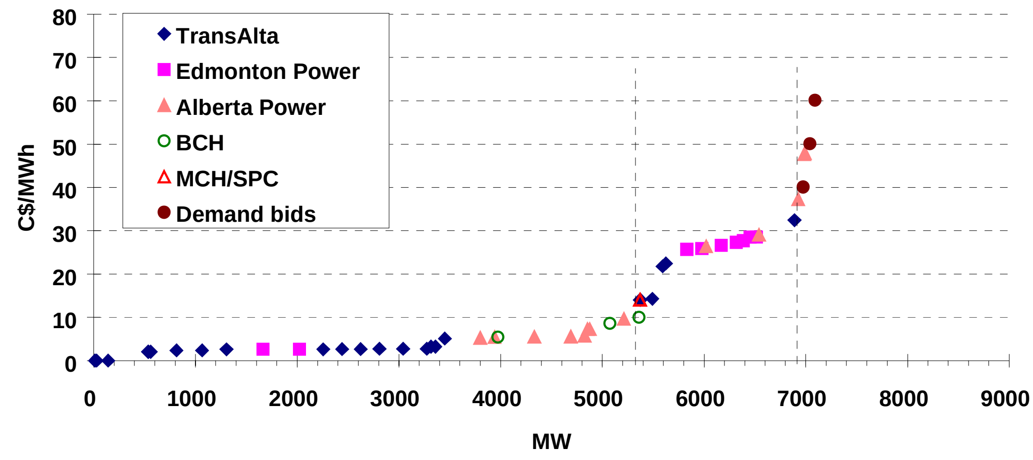
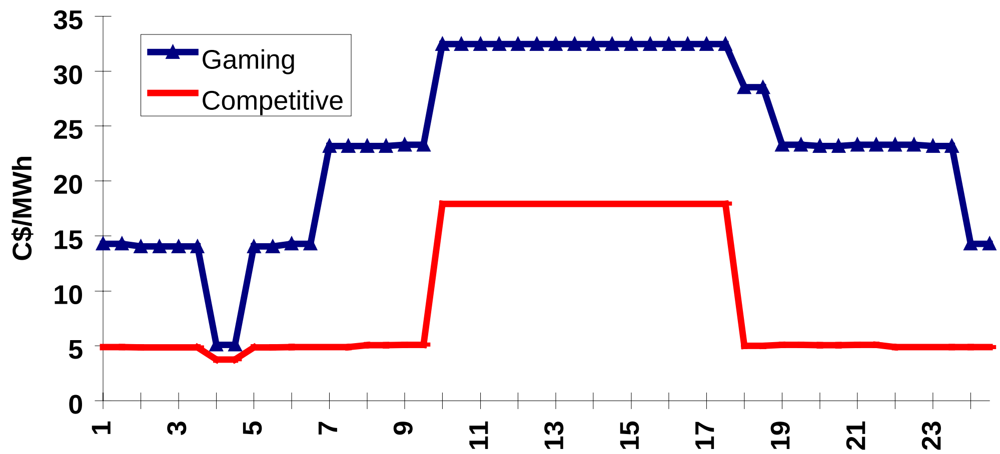
30 A dominant strategy is one played by a player no matter what strategies are employed by other players.

Figure 22: Commitment prices for medium day - 50% contract cover



In this bidding scenario we would also expect APL and Edmonton Power to bid up the final blocks of their marginal units, up to several times variable cost. This strategy is constrained only by the pricing of demand side bids in the market. APL's coal units can shadow against the EP Clover Bar unit, producing a relatively flat price curve as shown in Figure 23. The lower curve shows the projected price trajectory when all units bids their variable costs.

Figure 23: Daily clearing price - 50% contract cover



6.5.3 Preventing baseload withholding

From the above analysis it is clear that a 50% cover on TransAlta's baseload units is insufficient on this day type to remove the incentives for withholding capacity to push up prices. After some iteration is was found that 90% contract cover on the TAU units was required to remove incentives to withhold.[31] The supply curve with the resulting bid strategy of the other generators is shown in Figure 24.

This level of contract cover is high, but the TransAlta coal units are always infra-marginal so there should not be significant effects on Pool prices. The resulting price curve is shown in Figure 25. Note that prices are still well above the competitive outcome, for a relatively subtle reason.

Edmonton Power's Clover Bar gas unit is not committed for the day (to the right of the right hand dashed line in Figure 24. EP still has market power in this scenario, however. Clover Bar effectively caps the bids of the TransAlta storage hydro units which shadow-price against it, as well as the price bids of the most expensive coal units of Alberta Power. By increasing its bid, EP allows APL and TAU hydro to raise prices across a broad band of hours in the middle of the day, which increases the profits of the Genesee coal unit.

31 Based on 90% of capacity after expected maintenance and outages for the month.

Figure 24: Commitment price supply curve with 90% TAU baseload cover

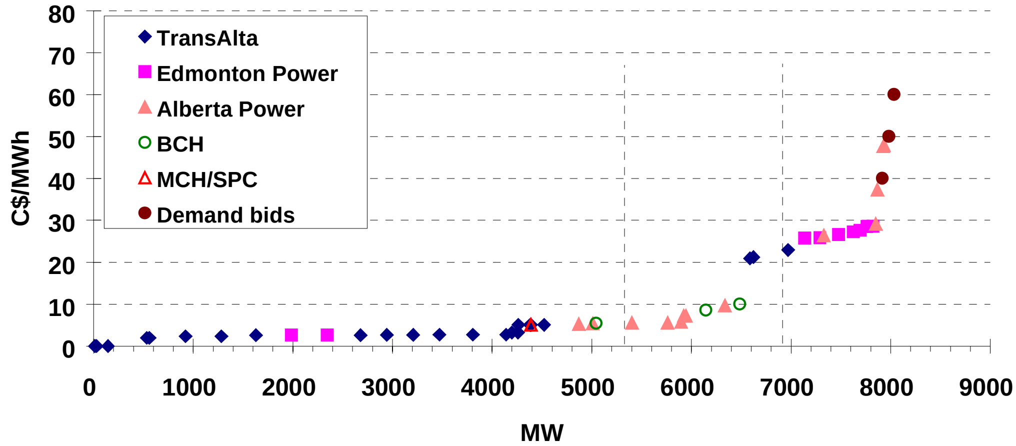
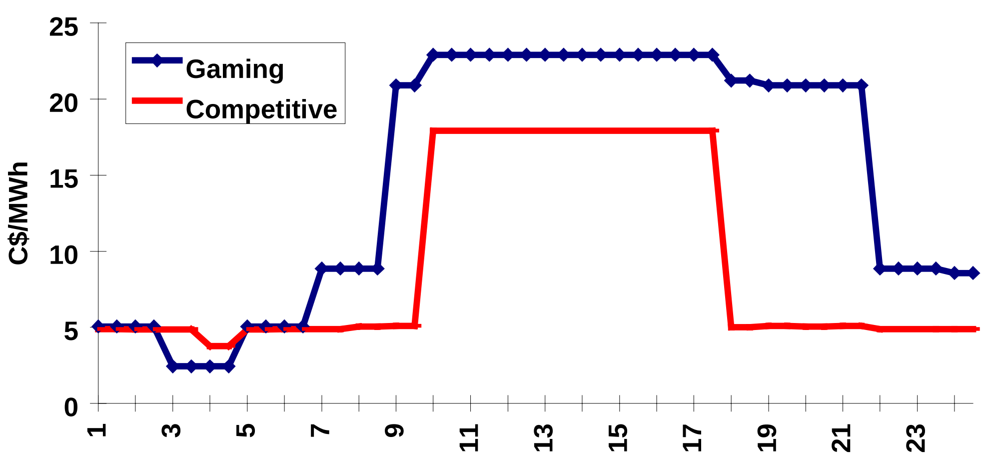


Figure 24 showed the bid supply curve for a one-shot game. Under these assumptions APL and imports are caught between pushing up prices during the day and maximizing the output to benefit from the prices. In a repeated bidding game (such as the Alberta Pool) a collusive outcome is highly likely under these conditions, where one generators bids up to set prices higher while the other maximizes output. A changing mixed strategy equilibrium is therefore likely.

Figure 25: Daily clearing prices - 90% TAU cover



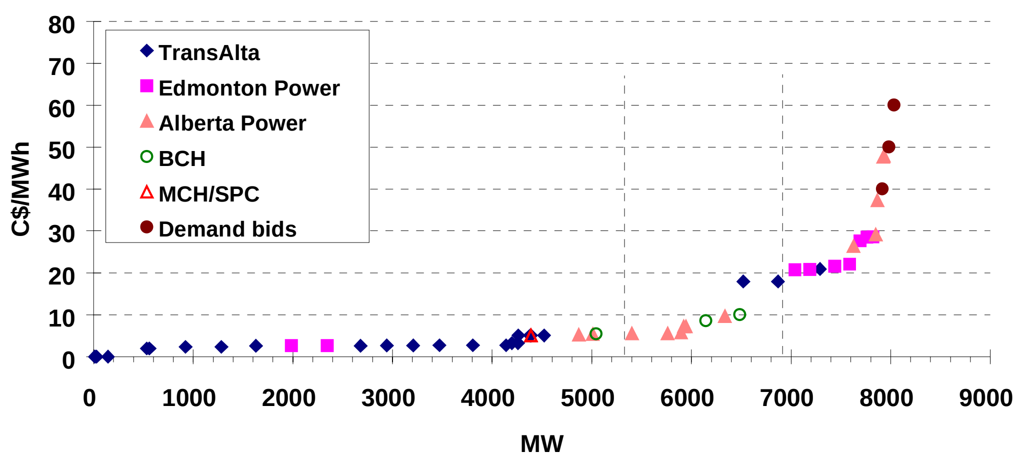
6.5.4 EP baseload contract cover

An objective of the contract portfolio option is to minimize the potential distortion of market outcomes by having high levels of contract cover on marginal units, especially at peak. An effective method of changing the incentive to EP in pursuing this strategy is introducing contract cover on the baseload Genesee units which are able to benefit from increased prices set by Clover Bar bids.

It was found after some iterations that only a complete contract cover of Genesee was effective at removing incentive to increase Clover Bar bids. This is logical when it is realized that Clover Bar itself may not be dispatched, but only acts as a cap for APL, TAU hydro and import bids. The resulting supply curve under the equilibrium bidding strategy for EP, TAU, APL and BC Hydro is shown in Figure 26. Again note that the commitment prices shown in the graph are not identical to the prices used in setting prices by marginal units.

Figure 27 shows the resulting clearing prices. As expected, the APL coal plants and imports can still shadow price against the least expensive units of Clover Bar. Thus the clearing price remains well above the competitive bid price for much of the day, when these mid-merit units are marginal.

Figure 26: Commitment prices with 100% Genesee cover



In summary, the full contract portfolio which produces the outcomes shown in Figure 26 and Figure 27 consists of:

- 90% contract cover on the available TransAlta coal units, with no contracts on the TAU hydro units;

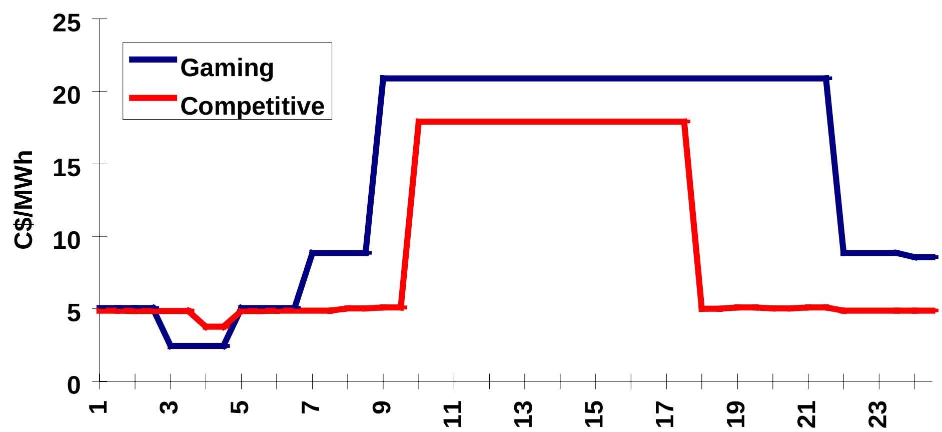
- 50% contract cover on the Alberta Power coal units;

- 50% contract cover on the Edmonton Power Clover Bar plant, and full CfD cover on the available capacity of the Genesee coal unit.

Our initial analysis has not shown contract cover on imports to be beneficial, since we seek to maximize their bidding flexibility in the Pool as a counterweight to the three main Alberta generators. However, we emphasize this conclusion is tentative since there is a broad range of import bid strategies which have not been tested.

In the next section we present the results of testing this initial contract portfolio against different demand levels and shapes from other days, especially peak days.

Figure 27: Daily clearing price with added baseload EP cover



6.5.5 Contract portfolio testing - low demand days

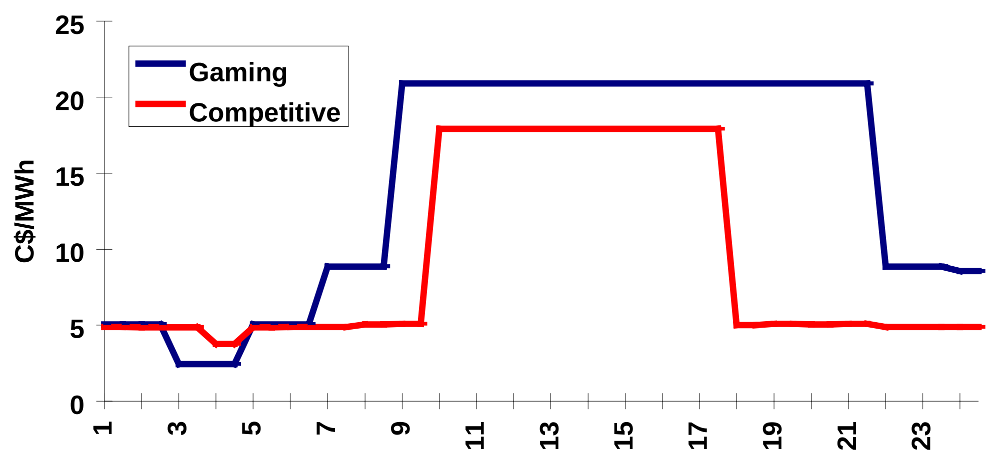
On a lower demand day, the imposed contract portfolio described above prevents strategic behavior for the major generators, with the possible exception of some games between BC Hydro as an importer and APL. In this demand scenario, BC Hydro would find it profitable to effectively withhold some 20% of its import capacity (by bidding in above the expected peak price), in order to allow APL to push up prices to just below the level of Clover Bar. A similar bidding strategy can be applied by Alberta Power with its coal units.

Given the shape of the supply curve without entry this form of bidding would be difficult if not impossible to prevent without a very high level of contract cover on APL and probably imports as well. We would expect that a collusive mixed strategy could occur in the context of repeated daily bids, where AP and BCH bid high-low or low-high to push up prices and maximize output.

The resulting simulated Pool prices are shown in Figure 28. By allowing APL and imports to shadow price against the gas units prices can rise across a broad tranche of hours, by a substantial level.

To reach a more definitive conclusion would require an exhaustive analysis of available import energy and pricing, which has not been possible in the time available.[32]

Figure 28: Clearing prices - low demand day



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[32] The prices of power available from BC Hydro/Powerex can be assumed to be effectively set by the opportunities in other markets, e.g. the U.S. Pacific Northwest. We have based our modeling of imports on historical import bid data and have not attempted to determine the true opportunity cost to importers across the BC and Saskatchewan tie lines.

6.5.6 Contract portfolio testing - peak demand day

The contract portfolio gave no stable equilibria from peak days above the competitive outcome with a moderate level of demand side bids. The demand shapes modeled were based on peak days from 1996, scaled to reflect projected maximum 1998 demand.

We would caution that this result is highly dependent on the exact level of future demand and may be affected by other factors:

- we have tested only a limited range of generator strategies. Before relying on this level of contractual cover in such a tight system additional analysis will be required;

- the design of the Alberta Pool allows single-hour bid strategies to be applied, where prices and quantities are bid independently for each hour. These have not been analyzed in any detail; and

- we have investigated only single-shot games. Collusive behavior might be expected in this tight system at peak if demand and supply conditions can be adequately forecast by bidders.

Of course, in the limit it must be recognized that market power cannot be controlled by any contractual mechanism when every available unit must be committed to meet demand. As this occurs on future days we expect prices to rise to the value of lost load. This in turn should attract new entry into the market.

7. Policy recommendations

In this section we present our policy recommendations for the Alberta Department of Energy, based on the empirical modeling summarized in Section 6 and the market design review presented in an earlier section. Our recommendations are divided into several topics, covered in the next few sub-sections.

7.1 Implementation of retail competition

- ***The potential market power problem in the provincial generating sector is especially severe.*** Lifting of the legislated hedges should not occur until an appropriate mitigation strategy is in place. Changes in market structure are the preferred method of addressing these issues in an industry so heavily concentrated and segmented. Regulation and market surveillance can play a useful adjunct role but should not be relied upon if an efficient and competitive outcome is desired.

- ***The existing legislated hedge structure is probably distorting competition in the Pool and hindering entry by new generators.*** The current legislated hedges act effectively as a nearly complete one-way CfD. While this structure has been successful at keeping down prices, it produces incentives which are probably distorting market behavior as Pool prices have in general appear to have been below average costs.

7.2 Market design

- ***We believe it unlikely that a change in market design would be sufficient to remove the market power problem in Alberta.*** The basic structure of Alberta Pool is one that has worked well in other parts of the world (e.g. Australia). The creation of other voluntary forwards markets will allow generators to shift profits, rather than correct the problem. Based on our experience in the England and Wales pool we also find it unlikely that a workably liquid forwards market can exist arbitraged against a spot market which is open to manipulation. In any case the efficiency gains from such a market appear limited in a system dominated by portfolio generators, compared to the potential productive and allocative inefficiencies produced by a non-competitive spot market. The development of such a market should therefore be placed as a lower priority.

- ***Measures to increase the price responsiveness of load should be implemented.*** The peak pricing mechanism in an *ex post* pool is highly dependent on demand side bids. The level of legislated hedges is itself one reason so little curtailable load exists, since distributors face a fixed transfer price and the Pool price is largely irrelevant in financial terms. Distributors could also be required to offer Pool price pass-through contracts to industrial consumers. The opening up of retail competition will encourage some demand response based on price.

- ***The scheduling and bidding of imports needs review.*** The bidding of imports through multiple virtual units gives importers an unfair advantage in price discovery. While imports play some role in limiting the bidding behavior in the Pool our analysis shows that imports may also be important in influencing prices in some periods of demand. The use of the virtual unit bid structure may improve the efficacy of these bidding strategies.

- ***The use of some activity rules should be considered before moving to hour ahead bidding.*** We are concerned that this proposal will hinder auction price discovery and aid tacit collusion. In a pure *ex post* market price discovery is difficult enough anyway. We would caution on moving to a new rule design until the competitive effects have been considered in depth.

- ***The rules for scheduling transfer capacity on the BC-Alberta tie line may need modification.*** We have not reviewed the transmission pricing and scheduling arrangements in detail. However, we are concerned that there is no "use of lose" requirement on transmission capacity, which may allow strategic bidders to effectively withhold or block capacity from the market for periods up to one month. An auction scheme for transmission capacity with a release provision may be one simple solution.

7.3 Mitigation options

- ***Do not rely on regulation to provide an effective competitive outcome.*** The use of price caps, screens and other forms of behavioral regulation are unlikely to produce the desired outcome. Since the key issue for generators is fixed cost recovery these mechanisms generally collapse to discussions over appropriate costs and returns to market participants. While market surveillance and the threat of regulatory review may be an effective adjunct tool to guiding the transition it will prove impossible for a surveillance committee to define an acceptable outcome over time. If regulation is desired then other, simpler methods are available.

- ***Do not rely on new entry alone to solve the problem.*** Over the short to medium-term the threat of entry will not give incentives for incumbents not to abuse market power. While sufficient actual entry would eventually constrain incumbent market power, our analysis has shown that even 1000 MW of new combined cycle gas-fired plant will be insufficient to make the market competitive over five years. New entry by must-run cogeneration units will be even less effective in constraining the bidding behavior of incumbents.

- ***Barring changes in industry structure, contractual mechanisms offer the best option for controlling market power in Alberta***. We recommend the use of auctioned bidding transfer contracts as a method of creating new competitors in the market. If this proves impossible the use of imposed contracts for differences to change the payoff structure of incumbents is a secondary option, but one that requires considerable development.

- ***Separate the mechanisms for rent transfer and market power mitigation to the extent possible***. The current legislated hedges both remove incentives for incumbent generators to raise prices in most hours, and transfer rents from generators to customers. The meeting of these simultaneous objectives is possible due to the full contract cover on the incumbents - i.e. these are effectively not in the market at all.[33] The auctioned bidding transfer model will allow these two objectives to be completed simultaneously but without distortion of Pool prices. No CfD portfolio without full coverage will be able to exactly transfer the differences between net book value and market value, where the latter is defined as net Pool revenues. If the imposed contract portfolio model is adopted the ADOE and Alberta stakeholders should consider the policy implications of other rent transfer mechanisms such as lump sum payments.

- ***Develop ancillary mechanisms and review processes in addition to contracts for market power control.*** No incentive-based mechanism is likely to curb extreme market power in the short term at peak, unless contract cover is nearly 100%. We suggest that some backup method will be required if deregulation is to continue without a change in market structure. Incentives for the latter can be placed in market power mitigation contracts through the use of trigger mechanisms.

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33 Although the bidding behavior of incumbents effectively controls prices in the market. Hence we can have the near paradoxical outcome of low Pool prices (below average costs) in a market which is short of capacity.

Acknowledgments and Notes

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The opinions and recommendations expressed in the report are those of London Economics and do not reflect the policy of the Alberta Department of Energy.