AQUILA ENERGY

Comments on the Form

of the

Power Purchase Agreement

and

Related Alberta Electricity Market Structure Issues

Prepared for: Independent Assessment Team

October 1, 1998

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Alberta Power Market Issues and Form of PPA

1) General

Aquila Energy ("Aquila") is an interested party in the development of the Alberta Electricity Market Structure. The current structure has major impediments to a fully competitive market. As the second largest gas marketer and the fourth largest power marketer in North America, Aquila is interested in participating in the Alberta market both as an energy marketer and a potential IPP and PPA holder.

As a touchstone to all the various decisions that have to be made, Aquila simply asks how would that particular issue have to work if the plant was simply sold outright to the buyer. What rights would the buyer have and what risks would they take. This proves very useful in cutting through the tangle of entitlements. Many of the protocols developed for this auction would be entirely unnecessary if all the assets were sold outright at a total auction.

The form of the PPA is just one of many issues that must be addressed simultaneously to reform the electricity market in Alberta. The choices made in the other issues affect the choice of the best PPA design. A liquid, efficient market will not emerge unless marketers have faith that the market is fair and that they can find convenient ways to keep their book roughly in balance. Any long term marketer will not consistently expose themselves to naked speculative positions. Aquila has attended several IAT and Power Pool sponsored forums and has constantly stressed seven related prerequisites to a liquid market:

A. *Firm is Firm.*

Market participants must have the discipline to deliver on their commitments. Suppliers must have faith that their supplier will deliver. If a supplier offers a firm load at a firm price, they should be required to deliver to the terms of the agreement or pay the liquidated damages of their non-compliance at the pool price. There can be non-firm deliveries also, but they need to be in a different pool. The structure of the ultimate system should create a situation where the bulk of deals look like simple bi-lateral agreements.

Energy and capacity needed for system support resources by the pool should be bought in the same way from the market, either as firm or spot. The PP should look like any other customer for those transactions. The cost of these purchases would be spread across the transmission like they are on the Nova system in gas.

The Pro-rata load shedding protocol should not apply to any load declared firm. Aquila supports the PP proposal to allow an disco or customer to acquire firm load above their legislated hedge to protect as firm during a general curtailment.

B. *Market Power.*

As demand approaches full capacity, the equilibrium point moves into the inelastic region of the demand curve. At that point, revenue from remaining units increases at a higher percentage than volume decreases on withheld units, incenting the supplier to reduce volumes. The entity which has the authority to withhold capacity is the one which influences price. The larger the fraction of Alberta's total production an entity controls, the more likely they can single-handedly shift the supply curve enough to move the equilibrium price out of the elastic into the inelastic range.

In the current situation, and until more capacity is added (or more customers are able to sell their curtailment), even a small producer can shift the supply curve enough to move it into the inelastic range of the demand curve. Generally, however, the less control any one supplier has over the stock of supply, the more closely bids will follow variable cost. There is no way of precisely determining the maximum concentration that will preclude gaming, but it is certainly less than 65%. Aquila believes that, for a liquid market to emerge, between 10 and 20 players with no one supplier holding more than 15-25% is required. Any structural change, including the PPA form must encourage this level of concentration.

Another exhibition of market power is the Alberta-BC Tie capacity. There are several proposals being aired that will mitigate this barrier to true competition, including the release of unused capacity on the tie (use-it-or-lose-it reassignment of hoarded capacity), making the transmission capacity resellable, using the Remedial Action Scheme (RAS) to increase the usable capacity of the nominally rated 1000MW beyond the 400MW practical limit, giving the end-customer more credit for offering up curtailment to the RAS transmission, restricting the use of "Network Economy" when BC Hydro is simultaneously exporting, and any other policy changes that allow more energy to flow in and out of the "energy island".

C. *Direct Access*

The more access to the open market given directly to price sensitive customers, either for buying or selling, the less market power will be an issue. For example, if customers who are willing to curtail can resell their entitled capacity to any number of marketers or other customers, not just the incumbent LDC, they will help arbitrage away any high prices that aren't supported by similar variable costs. Under the present structure, the customer has an implicit hedge for his typical volume at the embedded cost, which he notionally "owns". He should be able to resell any portion of that hedge or any other firm bi-lateral deals to whomever he pleases.

Similarly, if a customer is allowed to shop competitively for their shortfall directly from anyone and can be guaranteed that supply at a pre-determined price, they drive the price down,

D. *All Windfall Profits to Ultimate Customer* (Economies of scale, exclusive right to extensions, residual value)

The "social contact" between the government and the owner essentially guarantees that if the owner agrees to invest sufficient capital to deliver a prescribed level of service to its customers, the owner would be given a monopoly franchise and be given the right to charge a regulated rate sufficient to pay back his investment over the asset's life including a guaranteed return on the unamortized balance. Anything benefit coming to the owner beyond that is technically inappropriate, since the risks associated with creating that benefit were all born by the customer. Such benefits might include the exclusive right to extend the plant, the exclusive use of the economies of scale, or even the exclusive right to any remaining value at the end of twenty years.

The present proposal has some inherent opportunities for windfall profits for the incumbent owners. If the asset automatically reverts to the owner with no strings attached at the end of twenty years, it will definitely have some value. A more appropriate process would be to auction that right away, either to the buyer, packaged into the main unit, or through a separate auction. To be fair to the incumbent owner, they should be able to submit a bid as well. That offer might be in the form of a "shotgun" offer, such they would submit it as a "final offer" and anyone who could beat it by a prescribed amount would be able to buy at that higher price, without counter-offer from the incumbent. That would give the incumbent a slight advantage but would make them construct the offer very carefully.

Similarly, for extensions, the incumbent should be allowed to prepare a scheme to increase capacity. It would be auctioned and the value of the exclusive right to the extension output would be captured by the customer. The incumbent would be compensated generously for his development costs if he was not the successful bidder.

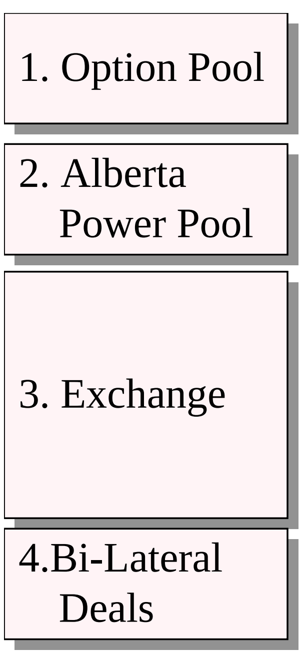
Aquila also recommends that some fraction of the existing stock of generation assets should be available for outright purchase.

E. *Encourage Cross-Basis trading*

The whole architecture, including the system of trading, standard contract sizes and terms of PPA's must encourage cross-basis trading. A wide repertoire of alternative ways of laying off risk makes the entire process more liquid. There have to be convenient, timely opportunities to swap between geographies (e.g. Alta Pool, Mid-C, COB), time (spot, hourly, daily, balance of week, month, year), fuel (e.g. gas to power to coal) and optionality (e.g. future for option, firm for non-firm). To facilitate this cross-basis trading, the standard size and term of contracts should match those in other jurisdiction . They must be small enough to be tradable and fungible (500-1000MWh).

F. *Pool Price Calculation*

Aquila believes that the gas industry has the best model for pricing . Essentially, the index price is the weighted average of a number of bilateral trades, rather than a single price for all transactions in a period defined by the intersection of the supply and demand curves (i.e. SMP). Enshrining the existing SMP structure will inhibit the development of the market. It lumps very different products together (options and futures) and tries to clear them all at a single price. Aquila's proposal would have a very minimal amount of power traded through the SMP pool price. The IAT or the DOE should consider having a four "pool" structure:



1. A pool of power to cover the "froth". A certain amount of power is needed to cover the instantaneous needs of the system. It would be impossible to predict the variations across each second of the day, or to even respond to it manually. The needs change too often to formally accept firm bids for each second. The people bidding into this pool must be willing to take the single clearing price. The calculation would be just as it is for the SMP, except only the participants who specified that they wanted to participate in that pool would be in the merit stack and the price calculation. Essentially, if the pool can't be firm and the supplier can't change their volume after the price is picked, make it as small as possible and don't transfer this volatility to the general load. The PP would be authorized to dispatch in merit order and pay on an ex-post price calculation. This is essentially an option pool in that the pool is not obligated to take delivery of the power if it decides not to, but the bidder has the obligation (with sanctions for no-compliance) to provide it if it is dispatched. Since it is an option, it would properly exhibit the volatile price characteristics. As long as these amounts are a very small fraction of the total load, they could have very volatile prices without significantly distorting the firm price to the ultimate customer.

2. The second stack would also be dispatched by the pool, but on a "lifted offer" basis. The PP would be authorized to lift an offer or hit a bid up to a reasonable time before the close of a period (say 30 minutes before the hour). They would lift an offer for power at the seller's price (ex ante) and terms, normally taking the lowest active offer first, (with some discretion for must-run units and ramp-up requirements) and it would be a firm commitment. The

seller could withdraw their offer until it was lifted, but after that would be forced to deliver at their price if dispatched. If the offer was lifted, the PP would be obligated to take the power. If the pool had excess capacity, it would be authorized to offer it back into the pool and hit the best bid. Their authority to purchase would be limited to hour, or perhaps day ahead only.

3. The third part of the pool, actually more of an exchange, would operate just like other commodity exchanges. All bids and offers would be visible but anonymous. Any participant could lift any offer or hit any bid. Bids/offers could cover the entire spectrum of time from next hour to next 20 years. There should be no limits on the number of times the power could be re-packaged and resold. Bids/offers could be firm or non-firm. All firm offers would be strictly firm. The non-complying party could arrange alternate contracts to meet their unfulfilled obligations to the pool until the cutoff time for the active time period. If they had not done so, the Pool would be authorized on their behalf to lift the best bid out of Pool #1, or #2 if still practicable.

Another function of this exchange is to provide a verifiable settlement index for derivative products. Aquila believes that the gas industry has the best model for developing this index. Rather than the SMP, which is a single, market-clearing price at the intersection of the supply and demand curves, the index would be based on the average of all firm trades transacted through this pool. Normal, balanced activity in this pool would not affect the price of the SMP pool (#1 above) or vice versa.

Aquila strongly discourages using the BP as the counterparty in this Pool #3. This service should probably be provided by a third party screen-based operator such as NGX or Quicktrade. To make the market convenient and fast enough to be liquid, that screen operator should be the counterparty both ways between the buyer and seller and would be responsible for the creditworthiness of each. They would also do the dynamic Value at Risk calculations to determine when a margin call or trading restriction would be invoked. If it were not possible to give this function to a an independent screen operator, the much less preferred option would be to have the buyer and seller disclose themselves and make their own credit check before agreeing to the trade.

The process should be structured so the bulk of trades, including those which are currently part of the legislated hedge, would go through this pool. A Disco would have to discretely contract with a marketer or generator for the bulk of their load. As the market matured, the screen operator could probably do the Pool # 2 transactions as well, with the BP as counterparty.

4. A fourth exchange process should also be allowed for simple bi-lateral trades. Aquila sees the advantage of having a large number of visible transactions . However, there is also a place for a certain number of confidential, over the counter trades strictly between two counterparties. The trades would have to be registered anonymously with the TA and/or the PP so they could be recognized for balancing, but would not affect the price of the other pools. Power traded between two parties could be firm or not firm. If it was firm, they would be the last customers to be turned off and only for a force majeure. The generator and the customer would both have to meter their loads. Each would pay any imbalance at the SMP in Pool#1 unless they arranged for alternate firm balancing supply before the cutoff time. The counterparties would be the two parties themselves.

   There must also be the clear opportunity for any contract in any of the pools to go to physical delivery. Without that threat the prices for the various bases will not necessarily converge.

G. *Leave the Hedging to the After-Market*

Once the market has more liquidity, most of the anticipated hedging can be given to the after-market to deal with, including the Stable Rate Option. Fuel pricing would be left to the marketer to determine whether they can take the exposure or hand it off to a third party. They would just use the generator as a tolling plant, turning gas or coal into electricity, but not owning the fuel. The Disco, as provider of the Stable Rate Option, would determine if it needed fuel price protection, and would find that protection in the open market and give the Stable Rate Option customer a flat price. If that was too expensive, they could offer the customer the choice to take the price risk. If they guessed wrong about what the customer wanted, more of their customers would move to the competitive priced goods. In that case, the Disco should simply be seen as an aggregator of end-use customers. The end-use customer should be able to opt in or out of those arrangements and should have a right in either scenario, to harvest the legacy of cheap embedded cost by using the same excess Balancing Pool proceeds as anyone else. The disco should have no more right to the customer than anyone else.

2) PPA Issues

A. *Parties to the PPA's*

In Aquila's view, the buyer and the owner should be the counterparties in the original sale of the PPA's. For the necessary instantaneous real-time balancing, the small Type #1 pool needs to be administered centrally. In that special case, the buyer is actually the pool itself, so the owner and the pool would be the counterparties.

The main problem with having the owner and the buyer as counterparties is that it forces the owner to enter into an agreement with a party without explicitly approving the credit risk. One would expect the party tasked with evaluating bids will perform due diligence on the buyer to confirm their creditworthiness. That removes some of the concern, but the owner's complaint is still valid. If one accepts the concept of the owner not being entitled to windfall profits (see above), the risk to the owner is limited to the unamortized value of the asset, minus its residual value at end of its prescribed life (or twenty years). It could be argued that the Balancing Pool is the trustee of the balancing fund and that that fund would appropriately be used to backstop the exposure of the unamortized asset repayment. If the owner defaults, that would cause costs to the buyer, which he should have implicitly built into his offer. Any other contractual obligations beyond that between the owner and the buyer are appropriately born by the owner or the buyer.

The pool should have a restricted role to play when a buyer defaults. That role should be to assign the equivalent of a receiver in a Bankruptcy proceeding. The receiver would put together an emergency team to run the business of the buyer until another buyer could be found, either by auction, or by assignment. The creditors would decide if the sale would be by auction or simply a negotiated assignment. One of the creditors, the generator owner, would claim his rightful stream of payments as long as he met his availability targets. The Balancing Pool would be available to backstop the difference between their entitled payments and the amount the interim company could pay. An auction would not be as important for this second time, since the balancing pool had supposedly already extracted the economic rent from the original sale and made that available to all customers.

B. *Assignment of PPA's*

Aquila supports allowing the assignment of PPA's (owner or buyer), subject to the approval of the counterparty, not to be unreasonably withheld.

C. *Conditions of Sale*

Aquila recommends the firm-physical model. Even the firm-financial formulation allows the owner to withdraw capacity (i.e. shift the demand curve left) and shift the supply/demand intersection of the market from an otherwise elastic region to an inelastic region and extract economic rents. The buyer should have the sole and unfettered right to withdraw or submit the unit to the system.

The PPA should include a prescribed firm availability with a shape (sculpted). It may not be practical to actually prescribe 8,760 (i.e.365 days*24 hours) different outputs, but at least a monthly availability target should be determined (preferably a close approximation of previous years or previously presented test years). One workable compromise would be to require the owner to define a monthly capacity and energy target. This would entitle the buyer to the specified capacity at any time during the month, but his total energy would not be allowed to exceed the energy specified. If the buyer chooses to use his whole allotment of energy at the highest capacity at the front of the month, he would not be allowed any further energy for the rest of the month. A prudent buyer would schedule his consumption across the most highly priced hours.

Each different type of asset would have a different capacity factor, the ratio of the total energy to the product of capacity times total hours in the period. For example, in a month with 720 hours, if the capacity was specified at 10MW, but only 3750 MWh of energy were specified, the capacity factor would be (3750/{720*10})=52.1%. A base unit like a coal-fired plant, would have a near unity capacity factor. The buyer would have to run it almost all the time to use up his energy allotment within the capacity envelop. A Gas turbine would have a very low capacity factor, so the buyer would run it hard during high price periods and not at all during low price periods and still be able to use up all the entitled energy.

During a month an owner had planned maintenance, he would leave the capacity the same but lower the energy available. That would give the same effect as Enron's submission that the owner specifies a maintenance window but the buyer chooses the schedule within that window.

The owner would be asked to set the capacity and energy specifications by month, negotiating and defending any deviation from the historical averages for that unit. Performance measures would be negotiated from those targets after full disclosure and scrutiny by a panel of interested stakeholders, much like a standard rate hearing.

Selling just the rights to the output of the plant and not the plant itself will likely result in windfall profits to the owner. In the worst case, it could motivate the owner to defer prudent extensions nearer to the end of the life so they can maximize the residual value they would automatically assume. To avoid this inappropriate allocation of wealth, all potential *buyers* should be offered the option to buy out the asset at the end of its useful life at remaining unamortized capital cost. This option could be packaged into the main unit offer. Alternatively, there should be an auction for those residual value and extension rights, either at the time of the main auction or at the time of the planned expiry or extension date.

To be fair to the incumbent owner, they should be able to submit a bid as well, at least within the bounds of the concentration threshold. That might be in the same form of a "shotgun" clause as in 1) d) above, whereby they would submit as a "final offer" and anyone who could beat it by a prescribed amount would be able to buy at that higher price, without counter-offer from the incumbent. That would give the incumbent a slight advantage but would make them construct the offer very carefully. If another party won the auction, the incumbent would be generously reimbursed for the development costs.

The PPA process should require some fraction of the existing asset base to be sold outright.

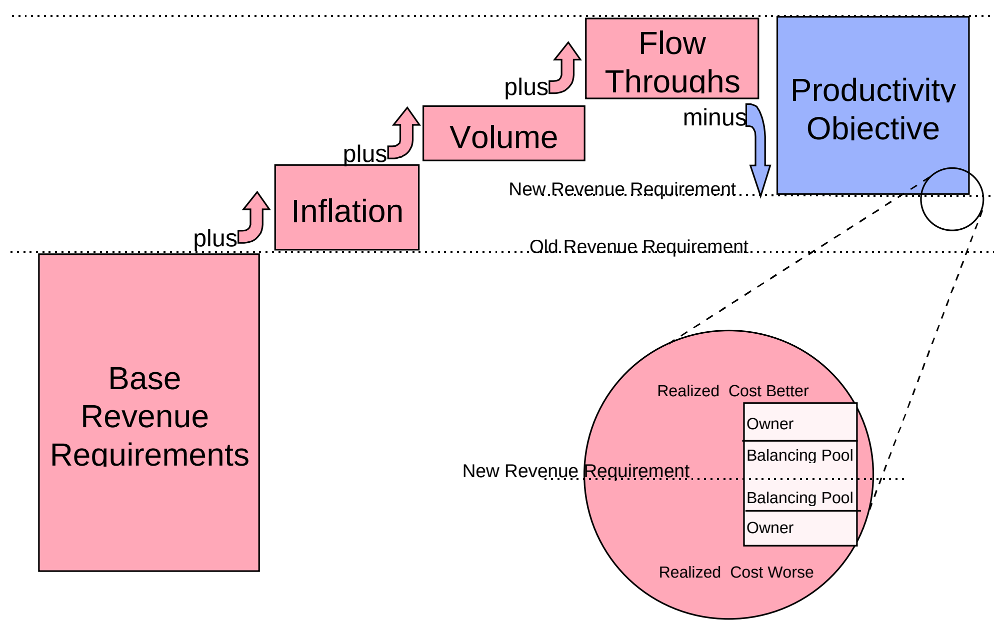
The IAT should explicitly address the possible contingency that the auction is undersubscribed.

D. *Performance Incentives*

Aquila strongly supports a performance incentive which rewards or sanctions an owner for performing better or worse than specified in the PPA offer. This creates the need for a defensible mechanism to generate a reasonable benchmark that constitutes an achievable but ambitious target availability. Assuming the stakeholders can agree on a fair method to set this benchmark, the performance should have a series of indices similar to those West Kootenay Power ("WKP") developed for their Performance Based Ratemaking process. WKP was the first power company in Canada to successfully adopt this process.

Essentially, the company proposes, and the regulator and interested stakeholders negotiate and ratify, a base figure. If there were a complete impasse, the BP could offer up the plant for auction with the bidders offering their best target base to be evaluated against the incumbent. Assuming a base is mutually accepted, that figure is adjusted upwards each year for a mutually agreeable inflation index, volume adjustment and specified flow-through items (e.g. fuel, labor agreements). Then a target productivity improvement target is similarly negotiated and used to reduce the baseline for each year.

Performance Based Rate Making



If a owner can consistently beat that adjusted price and availability, they share the gains with some agreeable formula, often equal and often symmetrical (share the upside in the same ratio as the downside). Aquila would support a study by plant to determine the skewedness and distribution of possible upside ad downside risk before determining the symmetry of the payout.

The gains should be limited to improvements in operating costs, not valued at the market price of power, but at their "embedded cost". Otherwise, it could create the possibility of the owner again receiving a windfall profit.

The current PPA proposals all presume that the performance incentive would be shared between the owner and the buyer. In the WKP model, the customer is also a party to the sharing. In a mature competitive model, the portion shared with the marketer would probably find its way to the customer.

If they consistently beat the target, there would be some onus on the owner to show they have prudently changed some long-standing operational process to allow that increase and are not just running the plant too hard. A series of qualitative measures is also monitored (safety, environmental, service).

Buyers should not be paid incentives.

E. *Term of the PPA*

Aquila would strongly prefer that the units be sold for the entire useful life of the unit, including the life extensions. Most of the submissions from the power producers raise the concern that limiting the PPA's to the full term of each asset will raise the stakes so high that it will restrict the number of viable buyers. The papers often talk about the marketer as the only legitimate buyer. One should really expect that individual customers (or a consortium of end-users) may buy a PPA as a long term hedge, increasing the likely number of eligible bidders.

While the price risk may increase with the longer term, it is mitigated by the very long term propensity of price to move towards the incremental cost of the latest technology. For the next few years, while the shortage of power in Alberta is most acute, and pool rules are in flux, the price risks are enormous. In the longer term, the price will gravitate to the price of gas fired Combined Cycle Combustion Turbines.

If the IAT decides to have shorter terms, they should at least take a portfolio approach, having at least some of the units sold for the full term.

F. *Size of Parcels*

There is an inherent dilemma in the choice of size of units for the auction. On the one hand, there are opportunities to optimize operation across the inter-dependent units of a multi-unit thermal site or a multi-locational dam system. On the other hand, the largest of these locations comprises about 27% of the total system capacity, probably not over the practical limit to mitigate market power and in a size range that will attract a workable number of viable contenders in an auction. The art of this exercise will come in finding the practical middle ground.

Aquila generally supports the Enmax solution of keeping the river systems whole and cutting the very large complexes into units or clusters of units, but closer to the 800MW range. At the very least, the minimum size for a non-hydro system would be a single axle. Practically speaking, only the Sundance complex would need to be disaggregated.

One solution to the dilemma of the joint costs would be to run the steam plants and coal mines as utilities with a prescribed, performance adjusted cost to be transferred to the turbines as a utility cost.

G. *Standardization of PPA's*

Even if the size of the parcels is in the 800MW range, they would still have a value over $500 Million each. At that level, there would still be under 20 different parcels. For that level of expenditure, serious buyers will take a customized approach to each unit. The specific detail required in each will be so site specific, there will be little benefit to complete standardization. That said, the outline of the data presentation could probably be standardized for each fuel type.

H. *Assigning Risks*

Risks should be assigned to those who have the greatest control over the outcome. The owner would assume the risks of achieving a target heat rate, meeting the maintenance budget and meeting availability targets. The cost of fuel should flow through to the buyer unless the owner enters into a self-supporting side deal with the buyer to hedge the fuel price. If the owner exactly met the target availability, they would be paid a prescribed amount. The buyer would assume the risks of the market price for exactly the power provided under the availability terms. The owner would assume the market price risks for shortfalls or excesses from that availability number.

That would leave the customer with most of the risks they now assume. For the most part, that risk is really an implicit flow through from the market price. There should be sufficient after-market providers (agents, marketers or the incumbent disco if the customer opts to stay on a stable rate option) to mitigate any risks (e.g. fuel price, regulatory changes) the ultimate customer wants to avoid without rolling those functions into the PPA.

I. *Force Majeure*

Force majeure should be absorbed by the marketer, and passed on to the customer as a premium on the unprotected rate or as a discount to customers who accept a force majeure exposure. To protect the "social contract", the owner should see his assets being repaid in a close facsimile to the old, normal regulatory environment, Depending on the jurisdiction's history of allowing rate stabilization funds, deemed equity ratios and carry forwards, the owner would eventually recover all its fixed costs that were not recovered during a force majeure, either in the test period, as planned, or in a subsequent rate hearing. This could take many nearly invisible forms such as a larger than expected rate base, equity deemed greater than it really was, the rate stabilization fund being allowed to be replenished sooner. That is appropriate and symmetrical to the arguments against any windfall profits.

Prepared: October 6, 1998

Aquila Canada Corp.

Date: April 19, 1999

To: Keith Anderson
Project Director IAT

From: Firm Customers

Re: Comments on the Proposed form of PPAs

The following are comments on the proposed form of PPAs following the April 13, 1999 meeting with the IAT. These comments are provided on behalf of the Firm customers comprising of:

The Alberta Federation of REAs
The Alberta Association of Municipal Districts and Counties
The Alberta Irrigation Projects Association
The Consumers Coalition of Alberta
The Municipal Intervenors
The Public Institutional Consumers of Alberta and
The Senior Petroleum Producers Association

1. Role of the Balancing Pool

The current restructuring proposals contemplate the Balancing Pool (BP) playing a backstop role in risk mitigation, under certain circumstances, if the auction of PPAs is deemed successful. If the auction of PPAs is deemed unsuccessful the BP would assume the counter party role and assume all contractual risks. Under the latter scenario the BP would require the necessary resources to manage all contractual risks.

Under the successful auction scenario, the IAT has generally taken the view that risks should be borne by the party who is best able to manage the risk and we agree with this principle. As a general principle, we would suggest any residual risk mitigation assumed by the BP should be shared, to the extent possible, with the relevant contracting party to ensure all parties have the maximum incentive to proactively manage risk mitigation. Further any cost or benefit passed through to the BP needs examination and approval by the EUB.

2. Force Majeure

The assumption by the BP of risks related to force majeure continues to be a major concern to customers. This concern is heightened by the inclusion in the latest PPA draft the occurrence of high impact low probability (HILP) events as one of the conditions of FM. Under the April 9, 1999 IAT proposals the buyer would be relieved of capacity payments in the event FM is invoked by the owner for any reason. Further the buyer can choose to terminate the contract after the lapse of 6 months. The BP is required to assume capacity payments to the owner during the FM period. However, there is no limit to the FM period and the amount of capacity payment the BP would be required to make.

In order to provide the right incentives, we recommend that specific performance or a payment in lieu of specific performance be required of the owner. This means owners will be required to make up the lost production at some point in the future. This incentive will be consistent with the way IPP contracts are generally structured. Further the circumstances surrounding customer backstop of certain HILP events in the regulated world are no longer applicable under the PPA world. The operating and maintenance practices of the owners will not be subject to frequent scrutiny in the PPA world as in the regulated world. There is no assurance owners and/or buyers have not run down plants by maximizing production with minimum maintenance expenditures in the early years leaving customers with the obligation to continue capacity payments. It would be very difficult for any regulatory body to police such abuses. For this reason the onus of demonstrating an HILP event is not the result of poor maintenance should be entirely that of the owner.

It has been suggested that requiring specific performance would require extending certain contracts beyond 2020 and this would not be consistent with the "effective term" specified in the Act. We submit, requiring specific performance after the FM event is not an extension of effective term. Rather it relates to fulfilling the contract requirements. Alternatively, specific performance could be provided from another unit owned by the same owner. As a last resort if the Act is deficient in this regard the matter should be brought to the attention of the Department.

3. Change in law

It has been suggested by the IAT that risks related to changes in law are best assumed by the buyer. Others have proposed the BP should assume some of the change in law risk. The reason advanced for the BP assuming any risk due to change in law is that it would minimize uncertainty with respect to that element of PPA costs for the buyer and therefore increase the initial auction price.

As a general principle the risk of change in law should be assumed by the party best able to mitigate the impact of the change. Based on this principle a change in law affecting the whole industry's costs should be assumed by the buyer as he is able to mitigate the impact through pricing of the output. On the other hand, risk of change in law that is owner specific should generally be assumed by the owner. Based on the regulatory compact the owner's cost change would in turn be flowed through to customers.

An increase in costs related to environmental emissions would fall under the category of industry costs. Although this cost may affect coal fired generation differently than gas fired it nevertheless affects a whole industry segment and is not owner specific. The IAT has recognized that although the buyer is primarily responsible for this risk the owner has a role to play in mitigating the risk. In the event of a dispute, the onus should be on the owner to demonstrate to the buyer that any change in costs due to change in law is just and reasonable.

The risk of change in law that is owner specific should be assumed by the owner and flowed through to customers to the extent it cannot be mitigated. The flow through amount should be subject to examination and review by the EUB. Change in income tax rates may fall under this category as there are taxable and non taxable owners of generation. Another example of change in law that can be considered owner specific is property taxes. Utility generating plants that are under the EUB's jurisdiction, municipal jurisdiction or governed by the small power research and development Act are presently considered linear property under Section 284(1)(k)(i) of the Municipal Government Act and subject to Schools tax. However, merchant generating plants are not considered linear property and therefore are not subject to the Schools tax and enjoy a lower property tax assessment. There is an imminent possibility that the property taxation method would be made uniform for all generating plant through a change in law. If this were to happen some owners would see cost changes while others will not. Accordingly changes in law affecting property taxes should also be classified as owner specific and flowed through to the BP.

4. Change in Tax Status

The IAT has proposed in its initial paper that any tax costs resulting from a change in tax status for EPCOR be assumed by the buyer. We have concerns with this proposal for two reasons. First, the issue is whether EPCOR should be able to pass on the tax consequences of ownership change to customers and/or buyers. Second, if there is to be a pass through of the tax consequences is it better for the BP to absorb this cost change rather than the buyer.

The timing of the decision whether to sell EPCOR's units or not affects the amounts flowing to the BP either directly or indirectly. Part 2 of the Generating Units Regulation provides owners the opportunity to sell their units subject to certain time constraints. Generally, an election to sell under Part 2 has to be made not later than 30 days following the IAT's report to the Board. The Regulations (Sections 17 to 23) also prescribe a method of distribution or sharing of the proceeds of sale to owners and customers. If an election to sell under Part 2 is made customers will bear the consequences of any change in tax status implicit in the sale price as well as receive any benefits resulting from the sharing of proceeds. If a timely election is not made customers will be faced with the tax consequences in the event of subsequent sale. They will likely not share in the proceeds. In our view EPCOR's proposal lacks symmetry. We recommend therefore that EPCOR not be compensated for the tax consequences of change of ownership in the PPAs unless there is a sharing of proceeds along the lines set out in the Regulations.

Our second concern relates to whether the buyer or the BP should bear the tax consequences of change of ownership. As stated previously under change in law, we propose, the impact of taxes should be passed through to the BP as and when ownership changes and the EPCOR units become subject to tax. This is likely to minimize the perception of risk on the part of the buyer. Further there would be less likelihood of the buyer terminating the contract resulting ultimately in the BP having to take over the contract. The impact of income tax changes should be approved by the EUB.

5. Excess Energy

The IAT's proposal on excess energy contemplates payment for excess energy based on the higher of owner's minimum excess energy price or pool price. Our concern is, to the extent a portfolio owner sees the pool price he could be motivated to manipulate supply. This market power concern would be exacerbated if the IAT were to set the committed capacity (CC) at a level where the owner has the ability to generate significant amounts of excess energy. We recommend that the bar for CC be set high enough to alleviate such market power concerns.

In regard to the dispatch of excess energy we agree with the IAT that the buyer should have the right to dispatch all energy including excess energy.

6. Asymmetry Effect

The IAT's March 26, 1999 paper on availability incentives proposes a revised availability incentive formula from that proposed previously. Under this formula the IAT proposes the following changes to address the asymmetry aspect of availability incentives:

- The use of rolling average monthly off peak and on peak pool prices instead of live pool prices to calculate the availability incentive payments

- The use of an ASAF allowance to recognize that some asymmetry still remains in the owner's ability to recover their costs

We wish to point out that the inclusion of planned outage, forced and maintenance outage rates in the target availability calculation shifts some of the asymmetry risk effect in favour of the owner. In contrast, the IAT's previous proposals contemplated a separate planned outage budget reflecting low pool price hours. The asymmetry in favour of the owner arises because the owner has the ability and incentive to move the preponderance of maintenance to weekends and other off peak periods although the formula assumes maintenance will be carried out uniformly throughout the year. This should be considered by the IAT in determining any asymmetry adjustments.

7. Up Front Capital Payment by the Buyer

The auction of PPAs is expected to result in initial capital payments by buyers into the BP. While this may satisfy owners' prudential concerns and provide assurance to customers that the buyers have a commitment to the PPA arrangement, the requirement for a substantial up front lump sum payment in itself should not be a deterrent to any buyer who may otherwise be prepared to purchase the PPAs.

Firm Customers' Preliminary Response to IAT Comments Dated July 31, 1998

The following are preliminary comments by the Firm group with respect to the IAT's July 31, 1998 communication. The Firm group consists if the following:

Alberta Federation of REAs
Alberta Association of Municipal Districts and Counties
Alberta Irrigation Projects Association
Consumers Coalition of Alberta
Municipal Intervenors
Public Institutional Consumers of Alberta
Senior Petroleum Producers Association

1. Firm Financial Vs Non-firm physical contracts

We see some merit in the classical capacity and energy payment PPA form (stated as non-firm physical) in that it would give control over dispatch to the buyer who is the right party to carry market and dispatch risks. However, there are certain issues to be addressed:

- Can the high degree of operational coordination required between buyer and seller under non-firm physical model be achieved without causing undue uncertainty from the buyer's point of view?
- Does the non-firm physical model provide adequate incentives for the seller to maximize plant availability? If target availabilities are going to be set under the non-firm physical PPAs could the same not be done under the firm financial model and perhaps achieve similar outcomes?
- With the firm financial model there is perhaps greater flexibility to bundle different units and even blocks of output from different units to address market power issues at auction time. The same flexibility does not appear to be there under the non-firm physical model.

2. Contract Counter Party

We agree that the Balancing Pool should not bear any risk that should properly be borne by the Owners and the Buyers. In this regard we see considerable merit in the buyer being the counter party to the PPAs. However, we see certain issues with respect to this matter:

- The EU Act Section 45.96(6) requires payments to the owners for electricity generation to come out of the balancing pool. There should be a mechanism for linking the buyer's interest of maximizing plant availability with how payments for performance would be made to the owners out of the balancing pool?

- Under Sec 45.94(1), the PPAs are to be converted to financial instruments if the auction is not successful (bids lower than reserve price). In this event would the balancing pool become the counter party to the PPA?

- The buyer as counter party requires the auctioning of 100% of capacity for the full effective term in a single auction. Would auctioning of 100% of capacity for the full effective term in a single auction result in significant price discounting? We note the IAT is giving further consideration to this matter.

- While the IAT has addressed credit risk issues from the point of view of protecting the seller, performance risk issues from the point of view of protecting the buyer have not been addressed.

3. Force Majeure

We tend to agree with the IAT that force majeure risk should be borne by the seller. Accordingly there would be no capacity payments during a force majeure event. The seller would avoid liquidated damages. This would be consistent with normal commercial arrangements.

4. Breach and Default

Not only the circumstances under which breach or default might occur but also the remedies available to either party if breach or default occurs should be clearly defined.

5. Change in Law

We agree that the change in law provision should have a threshold for cost increase decrease. Effects of changes in income tax law should be included in this category.

6. Assignment

The test of whether a party can withhold consent to assignment could be similar to the tests used to assess breach or default.

7. Plant Expansion

With respect to plant expansion we do not believe the Owner should have an absolute right for this expansion. In addition to concerns on the impact on unit operating characteristics there is a concern of an impact on costs that are flowed through the PPA.

8. Capacity Payments

These are some preliminary suggestions:

- A flat capacity payment over the PPA term would preserve availability incentives in later years. This would also obviate the need for management fees. We recognize the implications of flat capacity payments for the owners' current debt/equity structures.

- The capacity payment should reflect separate indices for the different cost elements.

- Annual depreciation rates and expense should reflect the residual value of each unit and associated facilities at the end of the PPA term.

- Capacity payments should preferably be sculpted across the year to reflect value of the capacity. Seasonal and time of day differences in value of capacity could be considered.

- Overall annual availability targets should recognize historical production levels including surplus/shortfall achieved for 1996, 1997 and 1998. The unit specific and industry best practice rates of change in availability levels over time may be considered. Availability targets could be sculpted across the year similar to capacity payments to reflect value of availability.

- Penalties for below target availability should be symmetrical with rewards for higher than target availability.

- As an incentive mechanism, there should be no capacity payments during planned or forced outages. The capacity costs related to these periods could be reflected through an increase in the capacity payment rate.

9. Energy Payments

We agree that there should be separate charges for start-up costs and no-load costs.

Payments based on net output will be consistent with the goal of maximizing output.

10. System Support Services

Giving the Buyer control over the supply of system support services to the TA would appear to be consistent with how a competitive market would work. We note that the IAT is conducting further investigations into the practicalities of this.

11. Limited Re-openers

The special circumstances under which changes, if any, to the PPA terms might be considered should be defined.

Nancy J. McKenzie
Barrister and Solicitor
11603 102 Street
Edmonton, AB
T5G 2E9
Telephone (403) 474-3592
Facsimile (403) 474-3593

October 16, 1998

Independent Assessment Team
c/o PricewaterhouseCoopers
21st Floor, 10130 103 Street
Edmonton, AB
T5J 3N5

RE: Risks Arising from Specific Provisions in Owners' August 31, 1998 Filings

As discussed in our meeting on October 6, 1998, the Firm Group generally approves of the direction the IAT has taken in its September 30, 1998 paper. However, we have also identified certain areas where we feel it is appropriate to ensure our concerns are brought to your attention and to ensure a more complete record. Although several comments relate most directly to the August 31, 1998 submission prepared by TransAlta Utilities, the majority of concerns apply equally to all three. Following is a brief summary of those areas of concern:

- PPA Counter Party – As discussed, the Firm Group supports the IAT's position the counter party should be the marketer, rather than the Balancing Pool. In our submission, having the Balancing Pool as the counter party is not consistent with the EUAA. Further, placing the Balancing Pool (BP) in the role of counter party may expose the BP to significant financial risk. However, we do agree the Balancing Pool could be responsible for absorbing any residual credit risk.

- Plan vs. Unit PPAs – The Firm Group also supports the position PPAs should be for whole units. This would avoid conflicts over dispatch. In cases where a plant PPA is considered necessary for efficiency of dispatch and coordination, we would also expect the IAT will give consideration to market power in the design of such station wide PPAs. Further, when PPAs are assigned, we submit the approval of the Market Surveillance Administrator be required to ensure market power considerations are not compromised.

- Non Firm Physical Contracts - We support non firm physical contracts with strong incentives for owners to make units available each hour, with added incentive to ensure availability or improve availability during high pool price hours. We understand the PPAs would specify a contracted capacity (CC) and an available capacity (AC). The difference between the two would be the allowance for planned maintenance and forced outage. Incentives would be determined around the available capacity. In our view, the level of contracted capacity should be set so there is no opportunity to produce excess energy from the existing installed physical capacity of the unit.

The Firm Group also favours symmetrical incentive payments to owners reflecting historic pool prices, set ex ante and reset periodically. To ensure pool prices are not manipulated by portfolio owners, in anticipation, by withholding capacity, the historical hourly prices could be selected on a random basis for peak, shoulder and off peak periods.

- Excess Energy – We understand excess energy to be the energy produced over and above the contracted capacity. In our submission, the owner should be required to negotiate with the buyer (holder of the PPA for that unit) for the sale of excess energy resulting from capacity additions. The buyer would continue to dispatch the unit to mitigate market power issues. Further, when the owner adds capacity in this fashion, there should be a requirement to provide a contribution or royalty to the BP for use of existing unit specific and/or common facilities. Should the owner and buyer be unable to reach a settlement, the matter(s) in dispute should be referred to arbitration.

- Capacity and Energy Payments – The depreciation expense included in capacity payments should reflect recovery of the capital cost of each unit, plus or minus positive or negative net salvage, recovered over the base life or life extension period of the unit. The net salvage should recognize site value if the IAT determines there is positive site value at the end of the base life or life extension period.

  Appropriate indices may be used to index costs over the life of the PPAs. Where an owner has a cost advantage with respect to a fuel source, this must be reflected in determining the index formula. Gas price risk should generally be assumed by the counter party as they are likely better able to manage this risk.

- Definition of "Change in Law" - Simply stated, the definition is far too broad. Specifically, the Owners suggest including administrative interpretations and positions as well as any recommendation concerning industry standard. While these may be useful tools in the management of a business, they do not have the same force or effect as a law enacted in legislation or established through the decision of the Courts or applicable regulatory agencies. Consequently, they should not be included as a change in law nor be allowed to affect the terms of the contract.

- Force Majeure – As noted during our discussion, two issues arise with regard to the Force Majeure provisions. First the definition is far too broad. It appears to encompass everything from earthquakes to any type of breakdown of the unit. It is necessary to limit the definition to exclude events over which the Owner has direct or indirect control or responsibility. In our submission, Force Majeure provisions should be designed to ensure they do not become a convenient means for escaping incentive penalties when a unit is down, particularly in the later years of a unit's life. As an added incentive, consideration should be given to making capacity payments on a levelized basis over the life of the PPA as opposed to a front end loaded basis.

Second, there is an issue concerning the effect of a Force Majeure. Although s.14.1 of TAU's proposal states the obligations of both parties will be suspended during a Force Majeure, it then goes on to state the counter party will still be required to make its payments under the agreement. The Firm Group's position is the buyer should not be required to make capacity payments during Force Majeure. The owner may mitigate the risk either through insurance or a reserve account to the extent cost of commercial insurance is prohibitive. Customers may bear some of the residual risk through cost flow-through mechanisms into the Balancing Pool for the reserve account or commercial insurance premiums, if they exceed a threshold amount.

- Definition of "Good Operating Practice" - Generally the definition proposed by TAU is consistent with the standard of care ordinarily employed by the Courts. However, any consideration of what constitutes reasonable judgement in the operation of a unit should include consideration of facts reasonably and actually known at the time a decision is made. In other words, the operator has a duty to ensure they have acquired all knowledge reasonably required to assess a situation and to make a decision. Further, if the operator has actual knowledge which suggests a different or unusual course of action, the operator should not be allowed to rely on normal or standard operating practice as a defense for any claim arising from an incident. Accordingly, we recommend the wording of the definition be amended to include such wording. For example, in TAU's proposal, we suggest "…methods and acts which, in the exercise of reasonable judgement in light of the facts *reasonably and actually* known at the time the decision was made…"

- Definition of "Planned Outage" - The concern with this provision is the suggestion the Parties may reschedule or alter the duration of any planned outages. The unit availability incentives should be structured to ensure Owners' interests and the interests of counter parties are congruent.

- Interruption of Supply – In s.5.2 of TAU's submission the Generator is permitted to interrupt supply for a wide variety of reasons including "any construction, maintenance, operation, repair, replacement or extension of its equipment…" Although aimed at allowing interruption to safeguard life or property, the applicable circumstances under TAU's definition are far too broad. Any interruption should be limited to circumstances where an emergency exists. It should not include periods of ordinary maintenance or construction (particularly if the construction is not related to the maintenance and operation of the existing generating units).

  As with the provisions affecting Force Majeure, there is also an issue concerning the counter party's obligations to continue capacity payments during an interruption of supply. We submit where a true emergency exists, it should be treated the same as a Force Majeure. Specifically, during such outages, the obligation to make capacity payments and the potential to incur availability penalty should be suspended.

- Expansion of a Unit or Facilities – TAU proposed the operator may expand his unit at any point provided written notice is first given to the counter party. In our view, unless otherwise agreed upon between the parties to the PPA, any outages caused by the expansion of a unit should be treated in the same manner as a Planned Outage. Namely, the obligation to make capacity payments would continue but so, too, would the potential for incurring of availability penalties.

- Default and Termination – As noted in our meeting, the provisions under default and termination are exceedingly onerous on the counter party. This is clearly illustrated by the fact the counter party is still required to pay the generator an early termination amount even if the agreement is terminated by reason of the unit being destroyed. To be consistent with the approach suggested for occurrences of Force Majeure, we recommend the requirement for capacity payments and the assessment of availability penalties be suspended in the event the contract is terminated due to the destruction of the unit.

Should you have any questions or wish to discuss any of the foregoing points in more detail, please call.

Yours truly,

NANCY J. MCKENZIE PROFESSIONAL CORP.

Per:

NANCY J. MCKENZIE, LL.M.

Summary

Purpose of the PPAs

PPAs were conceived as an alternative to plant sales to achieve two goals:

(1) Preserve customers' entitlements to the low embedded cost of power; and

(2) Prevent the potential abuse of market power through increased competition.

Unless *both* of these goals are met, there is no advantage of the PPAs over the current mode of regulation-cum-negotiation. If the IAT adopts many of the Owners' positions, the PPAs will meet *neither* of these goals. Costs will be higher than under the current regulation and market power will still be a problem.

Specific Concerns About Proposals

Deregulation of generating plants makes sense only if it leads to improved performance that cannot be achieved under regulation *and* customers benefit from those improvements.

According to the Owners, operating expenses under the PPA regime will be higher than they have been in the past, notwithstanding previous claims that efforts were being made to improve productivity. Similarly, proposed capital expenditures greatly exceed historical levels.

Output, on the other hand, is forecast to decline. The Owners attribute this to the effect of aging. However, they have not included any potential for improvements in technology and operations.

Even with this forecast of higher costs and lower output, the Owners claim that the PPA regime entails substantially more risk than regulation. This translates into higher returns, which further increase the total cost. The Owners also want protection in the case that the PPAs become uneconomic. The irony here is that the costs they want to include could contribute to that outcome. Although the plant itself might continue to be economic, the contract imposed on the buyer would not be.

The Process

The IAT was hired to provide an *independent* assessment of the type of contract that will achieve the goals. The IAT should take a "business" approach, which captures the type of aggressive assumptions regarding productivity, synergies and potential in the units that would be made by an independent buyer. The process should not become a "quasi regulatory" one, wherein the IAT simply balances the interest of all parties, and must be bound by the studies submitted by the Owners.

The Owners have been very thorough in documenting the various risks to which they are exposed. On the other hand, they have paid little or no attention to the potential for additional value to be realized. We believe both of these must be taken into account in determining what type of PPA provides the Owner a reasonable chance of recovering its reasonable costs.

A fundamental problem in the IAT process is that the Owners have exactly the opposite incentives that they would have in an asset auction. In an auction, the Owners' incentive would be to maximize the apparent value of the plants by stressing their reliability and potential productivity. The incentive here is to minimize the expected value of the plant (e.g., output) and maximize the expected costs. Other jurisdictions have realized that the only way to avoid these negative incentives is an actual auction or to have independent appraisers that take a similar approach.

Conclusion

Unless the IAT uses a process that minimizes costs and maximizes value, the PPAs will fail in their purpose of retaining for customers the benefit of low-cost power.

Market power will continue to be a problem because the Owners' unregulated affiliates control a substantial portion of new generation being built in the Province. This situation can only get worse if the Owners are allowed to control any of the capacity from these plants, either by buying PPAs or by controlling Excess Energy, betterment capacity or hydro dispatch. To have any hope of achieving the market power goal of PPAs requires excluding Owners from controlling this capacity.

Plan B

IPCAA is concerned that there is no clear contingency plan ("Plan B") in the case that the PPA process fails. "Failure" can mean that the PPAs do not sell at all, that the amounts offered by marketers (to be paid to the Balancing Pool) are inadequate, or that too few buyers come to the party.

The *Electric Utilities Act* speaks of converting the PPAs to "financial instruments" in this event, but this concept remains undefined. IPCAA intends to submit its recommended "Plan B" in the near future.

Section 1

Introduction

Purpose

Alberta has already deregulated decisions on additions and pricing of new generation.

We are now considering deregulation of *existing* utility generation. But this makes sense *only* if (1) that deregulation will lead to significant improvements—higher output and/or lower cost—than continuing the current regime, *and* (2) customers will benefit from those improvements.

The Owners' submissions to the IAT amount to a claim that we cannot expect them to do any better in the future than in the past. Instead, they forecast higher operating costs, higher capital expenditures and lower outputs than we have seen in the past. And the Owners feel even those lowered expectations present them with significantly higher risks, which must be compensated for by higher returns. In addition, the estimated cost to customers of the IAT itself is probably in excess of $10 million. In summary, customers are offered less service at higher cost than with regulation.

Further, the Owners do not want full deregulation. They want the opportunity to profit from plant expansions and betterment, but want customers to retain the risk (through the Balancing Pool) of adverse developments.

Throughout the United States, deregulation has spurred utilities to increase productivity and reduce costs. In contrast, the Alberta utilities are proclaiming that they are unable to conceive of such improvements.

Plant Sales

The *raison d'etre* of the PPAs is that the current Owners wish to retain ownership of the assets. If the Owners were willing to sell their assets, we would not need the PPAs.

But, is it really true that the Owners don't want to sell their plants? In the United States, utilities are selling their generating plants right and left, usually for much more than their book value, with the profits going to customers. Perhaps the Owners are willing to sell them, but are waiting for circumstances that enable them to retain the profits for themselves than for customers. We know from the newspapers that a sale of Edmonton Power—in whole or in pieces—is under consideration. APL and TAU, on the other hand, have been rather closed-mouthed about their plans.

The PPAs should definitely not be used as a way of increasing the share of the profits that the Owners keep at the expense of customers.

Evaluation

Our evaluation of the PPAs proceeds on two levels. One concerns the question of whether the PPAs will, in fact, produce the results expected. The second level is what the PPAs should look like and what costs and expectations should be built into them. These two levels are obviously related. Unless the PPAs incorporate significant expected improvements, they will not accomplish the intent of deregulation.

In our evaluation, we refer back to two source documents, the London Economics report, *Options for Market Power Mitigation in the Alberta Power Pool* (January, 1998) and the Department of Energy's *Backgrounder on the Electric Utilities Amendment Act, 1998*. Reference to these is useful to review *why* we are looking at PPAs and what the intent was. Also, we incorporate information from other past and contemporary sources, including prior utility applications and Board orders, the ongoing 1999/2000 Phase I proceedings and market evidence from elsewhere.

IAT Approach

The IAT's approach to the issues makes a big difference in the results. We recommend that the issues, both individually and collectively, be evaluated from a "business" standpoint rather than a "regulatory" one.

A "business" approach to the issues considers the potential upside, not only the risks, the chance to improve performance through aggressive management, not simply "business as usual". In the business world, the "best" result for a seller is the highest sale price. In an auction of plants, the buyer who sees the greatest potential for improvements in operation and the greatest site value (e.g., capacity expansion) will pay the highest price. For PPAs, this means incorporating expectations of higher productivity, ongoing improvement, lower costs and expansion potential. For customers, this will translate into the highest value to the Balancing Pool.[1]

A "regulatory" approach strives for a "reasonable" answer in light of the different views of the parties. Regulators are bound by the evidence presented to them and, therefore, are unable to make assumptions of dramatic improvement. The last several years have shown that, when properly motivated, utilities can do much better than they had earlier. For example, as discussed in Section 3, all the Owners have achieved significant reductions in operating costs as the result of their own initiatives—reductions that the regulator could not have predicted or imposed. Whereas a business valuation relies on independent evaluation as to the potential value of an asset, a regulator is forced to rely on the utility submissions, which—no surprise—will tend to omit such potential value.

Fortunately, in transition situations, this regulatory approach is starting to be modified to reflect observed behaviour in competitive markets. For example, in 1995 the utilities in Massachusetts claimed that the market value of their generating plants was zero, but refused to offer their assets for auction to get a true markets value. The Massachusetts

[1] That is, the highest value that can be achieved in a competitive market; a higher value might be paid if the acquirer thereby obtains a monopoly.

Department of Public Utilities (DPU)[2] was faced with the need to make administrative valuations of the plants. The DPU said:

> *. . . [W]e believe that the easiest way to identify the value of an asset for the purpose of estimating mitigation would be through the sale of the asset, provided that the sale were conducted in a manner, and at a time, likely to maximize the price received. However, absent such a sale,* ***the assumptions used by a company*** *(and those proposed by intervenors) in mitigation projections* ***concerning the value of a facility should reflect the likely expectations of a successful bidder, e.g., that the costs to operate the facility can be driven down; that the output from such a facility can be increased; that efforts to market the output commodities (such as energy, capacity, reserves, AGC, and emission allowances) will be successful; that there is reason to believe that the price for market commodities will be high; and that the value of the equipment and site of the facility for repowering or the siting of additional or new capacity is high****. The use of assumptions in mitigation projections based on these expectations would be consistent with (1) the long-standing ratemaking principle that electric companies are responsible for matters within their control, (2) the goal of near-term rate relief, and (3) the need to provide the proper incentives for electric companies to maximize efforts to mitigate embedded costs.* (Massachusetts D.P.U. 96-100 *Electric Industry Restructuring Plan: Model Rules and Legislative Proposal*, 1996-Dec-30, emphasis added)

In the end, the utilities decided to sell the generation and received far more than book value for them.

In California, utilities auctioned most of their plants. However, PG&E is currently proposing to retain its hydroelectric assets. Under California law, this requires an independent appraisal. Last December, PG&E submitted its proposed appraisal process to the California Public Utilities Commission (CPUC).[3] The appraisal process resembles the activity of the IAT. The CPUC has commented:

> *For assets that remain under the utility's ownership or that are handled through an accounting separation, we will use an appraisal valuation to determine transition costs. Market valuation of assets through an appraisal approach will provide results superior to an administrative approach because the appraisal approach relies on independent industry experts rather than experts hired to support each party's position, as is common in regulatory proceedings.*

The testimony of a witness for PG&E, Mr. David Moody, was that:

> ***One observation from reviewing previous sales is that the purchase prices*** *are not necessarily supported by cash flows predicted from historical data****.*** *Many of the sales, based on both empirical studies and anecdotal evidence****, are based on aggressive*** *assumptions involving synergies with other physical or organizational assets of the bidders, or some other advantage perceived by the bidder****. It would be***

[2] Now called the Department of Telecommunications and Energy (Web site is www.magnet. state./ma.US/dpu/).

[3] The application is available at http://www.pge.com/about_us/hydro/divestiture/hydro-val _981211-pleading.html.

> ***the job of the appraiser to evaluate any potential for increasing the value of PG&E's hydroelectric assets based on market behavior towards these issues.***

We believe the IAT was not hired to be a quasi-regulator, relying primarily on utility-provided data, but was hired in order to provide its own independent assessment of value. The issues should be looked at from a business standpoint—that is, as if the IAT were a party seeking to acquire assets. In those cases, what would be the highest price it would be willing to pay?

Process

We do not understand the process by which the IAT is arriving at its recommendations. In a 1999-Mar-30 letter to the IAT, APL stated:

> *At the outset of APL's meetings regarding IAT draft #2, APL raised the problem of the mischaracterizations in the draft of this statutory instrument as an agreement negotiated between the parties.* ***The IAT said that it was its desire to work toward a negotiated agreement as opposed to a statutory instrument****.*

On the other hand, in its meeting with IPCAA and the FIRM Group on 1999-Mar-09, the IAT stated that it was *not* using a negotiation approach.

It must be remembered that the reason for appointing an *Independent* Assessment Team was that the Owners and the Customers were not able to negotiate commercial arrangements in place of the legislated hedges. The IAT is supposed to use its *independent* expertise to arrive at the results. The idea of a negotiated approach is fundamentally inconsistent with the goals of controlling market power and capturing residual value for the customers. Clearly, the Owners' approach in any such negotiations will be to hold onto as much as they possibly can. This is neither surprising nor is it wrong *in a negotiation setting*. However, the purpose here should be to arrive at the same kind of independent approach that, ideally, the market would provide.

Section 2

Objectives

Goals and Purposes of the PPAs

According to the Department of Energy's backgrounder on the *Electric Utilities Amendment Act*:

> *The power purchase arrangements will replace existing regulation, while ensuring that utilities have an opportunity to recover investments made in a regulated environment and that* ***customers continue to receive the benefits associated with existing low-cost generation****. A power purchase arrangement transfers to independent marketers the right to sell the output of a plant into the Power Pool.* ***These arrangements remove the ability of utilities to use their portfolio of supply to manipulate the Pool price****.* (emphasis added)

According to the Backgrounder, during the 20-year term of the PPAs, customers should continue to receive the "benefits associated with existing low-cost generation". In particular, customers should receive the "residual benefit", which is defined as "an excess profit that would not have been earned under a regulatory environment".

From these, we can extract two basic purposes of the PPAs:

Purpose #1: To provide customers the same cost of power from existing generation as they would have received under regulation.

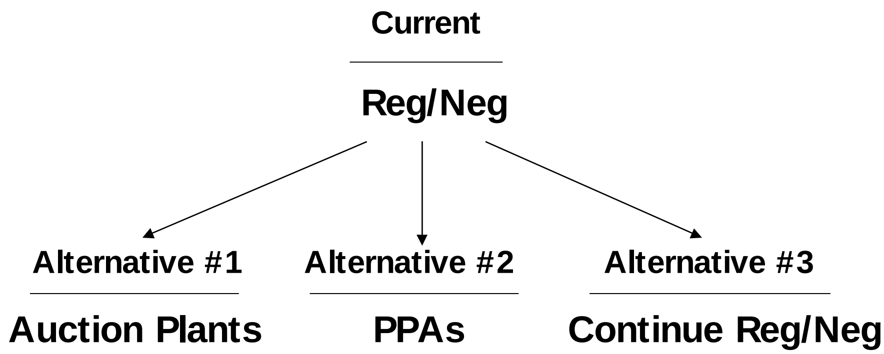
Purpose #2: To increase competition in the market and prevent the potential abuse of market power.

Success of the PPA process depends on achieving *both* of these goals.

Alternative Paths

Currently, the terms of the legislated hedges are set by regulation, but with heavy reliance on negotiation as an alternative—the "reg/neg" approach. Negotiated settlements were achieved for all Gencos in 1997 and 1998. A settlement has just been concluded with Alberta Power for 1999.

PPAs are one of three potential alternatives for treatment of existing generation.



Auction of the plants, resulting in multiple owners, is by far the best alternative to continued regulation. Dispersing ownership would reduce market concentration and thereby alleviate concerns about market power abuse. As London Economics noted:

> *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.*[4] (emphasis added)
>
> *For example* ***market power concerns in southeast Australia were partially allayed by structural reform generation involving some break-up of generation portfolios*** *prior to privatization. In England and Wales (E & W) the regulators 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*. (emphasis added)

Auctioning the assets would provide a true market valuation of the assets and, based on experience elsewhere, generate significant net profit by attracting top dollar.[5] Again, from London Economics:

> *Recent auctions in United States, Australia and Latin America had achieved far higher prices for generation than previously expected, often in markets considerably less attractive than the Alberta market.*

Appendix 1 summarizes the results of plant asset sales in the United States to date. Auctioning plants would give owners the incentive to "talk up" the capability of the plant, the potential value and the potential for cost minimization. The highest bids would come from parties who have the most optimistic views of their ability to reduce costs, increase output,

[4]By "market structure", London Economics means change in ownership, i.e., divestiture.

[5] We recognize that the highest value might be realized if the plants were all sold to one owner, who could then maximize his/her value by exercising market power. Thus, what we really want is the maximum value that can be achieved assuming a *competitive* generation market.

extract additional value from the plant site (e.g., by building additional generation) and the expectation of plant life extension.

The **Power Purchase Arrangements** have heretofore been viewed as a second best solution. Instead of purchasing the assets, potential buyers can buy contracts that give them the entitlement to the output of the plant at costs that are fixed by the terms of the contract. At most, though, this is a very distant second best because much of the value that can be realized by selling the assets will not be realized by selling contracts. New owners will have little or no ability to improve the operations at the plants or to realize the additional value at the plant site. In addition, the existing owners now have the incentive to inflate the perceived cost of operation and to understate the potential capability of the plant.

Continuation of the current reg/neg approach now looks more attractive than the PPAs in light of the last three years' experience. In 1996, continued regulation of the existing plants was considered to be undesirable, entailing significant effort by the Energy and Utilities Board and stakeholders and inhibiting progress toward deregulation. What we have learned since then is that the current reg/neg environment still gives Gencos strong incentives to improve performance and that the negotiation process gives customers a way of sharing in those benefits. In theory, the incentives of the Owners might be somewhat stronger under long-term deals. However, the PPAs as currently proposed give customers the certainty of higher costs (because of the allegedly high risks), with little or no assurance that they will share in any of the benefits from deregulation. In this case, the whole purpose of deregulating existing generation vanishes.

Main Concerns

Our main concerns are that: (1) PPAs will turn out to be more expensive for customers than the current reg/neg approach to setting prices; (2) the benefits of deregulating the plants will flow to the owners, not to customers; and (3) the PPAs will not be very effective in constraining market power.

PPAs Are More Costly than the Current Regime

The cost of power under PPAs is higher than with regulation. Customers will receive less value and owners will realize more income than under regulation. The owners have submitted cost estimates that are much higher than current costs.

For comparison, we show both the Fixed Costs and the Reservation Prices (which are Fixed Costs with some additions and subtractions). This two-part comparison is necessary because (1) the Fixed Costs alone are not available for 1997 and 1998, and (2) there is no calculation of surplus/shortfall or ancillary service revenues for 2001 and beyond. Also, we have shown the pre-2001 numbers without Rainbow, Sturgeon and non-interconnected plants, because these are not in the 2001 and 2002 numbers.

Cost of Existing Generation
<u>($M)</u>

Year (Source)	Reservation Price	Fixed Costs*	Fixed Excl RB,ST,NI
1996 (E97065)	$1,144	$1,162	$1,142
1997 (Negotiated)	1,113	**	**
1998 (Negotiated)	1,036	**	**
1999 (Proposed to EUB)	1,162	1,213	1,182
2000 (Proposed to EUB)	$1,172	1,234	1,205
2001 (Proposed to IAT)	N/A	1,316	1,316
2002 (Proposed to IAT)	N/A	$1,345	$1,345

* Fixed cost
- Ancillary service revenues
- Surplus (or + shortfall)
+SPRDA loss (TAU-G only)
=Reservation Price

** Negotiation on total basis; some details confidential.

Details are provided in Appendix 2. The total Reservation Prices for existing generation have decreased from 1996 through 1998. The fixed costs and Reservation Prices for 1999 and 2000 proposed by the Owners more than reverse this trend. EPGI, for example, has claimed that the prospect of PPAs increases its risk in the 1999/2000 period:

> *The generation assets of EPGI are subject to traditional utility regulation for test years 1999 and 2000. . . . But utility investors who establish the cost of capital in 1999 and 2000 are concerned with risks over the long-term and are not constrained in their risk analysis by the proper construction of test years for regulatory purposes.* ***Thus, recognition must be given to the PPA regime proposed for these assets when estimating the appropriate capital structure ratios and fair rates of return on common equity for 1999 and 2000.*** (Direct Evidence of Robert E. Evans for EPGI and EPTI, Page 3, emphasis added)

In the 1999/2000 Phase I filing, TAU's Treasurer claims:

> *In my opinion, and in the view of the management of TransAlta, the common equity component of its target capital structure needs to be increased for the period 1999 and 2000 from a deemed rate of 40% established by the Board in its decision of October 1997 to a minimum rate of 42%. Such an increase results from management's view that the financial cushion represented by this larger equity component will be required in response to:*
>
> 1. ***Higher levels of business risk anticipated as the market for electric power is deregulated****, as prices and sales volumes fluctuate in conjunction with changing competitive conditions in Alberta and as industry restructures both in Alberta and internationally; and*
>
> 2. *Tightened credit requirements, financial market volatility and the flight to quality investments caused by the turmoil in capital markets flowing from problems in Asia, Russia and Latin America.*

Another example is TAU-Genco's proposal to charge customers in 1999-2000 for coal that, in its view, will not be useful as a result of the PPAs.

Thus, according to this view, the PPAs are *already* reducing the benefit of existing generation that customers would receive under regulation. The extra cost to customers is even greater based on the Owners' views of what will happen in 2001 and beyond. The owners have included higher equity ratios, higher returns on equity, higher operating expenses and higher capital expenditures than we have seen in the past. The IAT has identified several of these problems. However, we have yet to see the results of any IAT adjustments to the numbers. The IAT's opinion is that the cost of equity in the PPA period is 100 basis points higher than under current regulation.

APL states that it will face much higher business risk than before because of (1) a high level of cost forecasting risk resulting from long-term contracts with minimal off-ramps, (2) risk that individual units would be unable to perform as required, (3) the potential for existing units to be replaced with power from lower-cost units, and (4) rising operating leverage associated with the declining level of investment. The result, of course, is a higher cost for customers (APL Response IAT-APL-21, dated 1998-Dec-21). This means that continued reg/neg will be cheaper for APL—and, therefore, for customers.

APL also claims that the IAT's proposed treatment of *force majeure* introduced more risk to the Owner than under the current system of regulation (APL Letter to IAT, dated 1999-Mar-03).

Trying to "deregulate" plants when ownership doesn't change and when market power is present requires adding a new layer into the equator, which by itself increases costs. As expressed by a TAU witness:

> *The complexity of those 20-year PPAs is starting to become quite a concern, I would say. The market power issue in a way has resulted in another participant entering the market in order to make the PPAs work. In other words, what I mean by that is the buyers of the PPA, and to the extent that any buyer or marketer that comes into Alberta and buys a PPA and sets up a retail business will wish to be compensated for doing that.* (Testimony of R. W. Way for TAU, Tr. 3104-3105)

Customers Will Not Benefit from Deregulation

APL has commented:

> *The value of the three-party model of market structure and risk allocation is that it deals with the purposes of the Act without resorting to wholesale changes in risk allocation. Such wholesale changes in risk allocation may appeal to some, but they have no apparent value or substance in terms of placing the Units within a* ***competitive generation market for the benefit of consumers*** *and they are certain to lead to the failure of this deregulation process in Alberta.* (APL Letter to IAT, Dated 1999-Mar-03)

A key phrase here is “benefit of consumers”. Unless there is a very high probability that the PPAs will produce benefits for consumers, the exercise will have been in vain.

With the current proposals, the benefits of any improvements will flow to Owners, not customers. The PPAs, as currently contemplated, do not provide any mechanism by which customers will get the benefit of modifications to plants. The IAT’s view of this is that the Owner and PPA purchaser can negotiate changes. That may benefit those two parties, but there is no guarantee that customers will see any the resulting benefits. This one-sided approach is evidenced by the comment of EPCOR that:

> *Clearly, the IAT has no authority under the EUA to require the Owner to obtain the consent of the Buyer prior to **developing Betterment Capacity for its own benefit**.*
> (EPCOR Utilities Inc. Comment, 1999-Feb-05)

Deregulation is supposed to allow Owners to make market-driven decisions about their plants. A true market-driven environment would free the Owner to modify, repower, or even shut down a plant, depending on what makes most business sense. However, Owners will not have the freedom to respond to market conditions, because the PPAs are still tied to the physical reality of the plants. This results from the Owners’ desires to have risks covered by customers (through the Balancing Pool). For example, if the plant goes out of service for a *force majeure* event, the owners want protection. But this means, equally, the plant cannot be taken out of service and replaced with a new one if the owner were to find it more economical. This is not purely academic. Some plants, such as Clover Bar and Rossdale, have such high operating costs (including nominally "fixed" costs such as labour), that it might be more economic to replace them with totally new plants.

PPAs Will Not Control Market Power

It is becoming more apparent that the PPAs will do little to solve the market power in Alberta. The basic problem was described by London Economics:

> ***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 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.*

The Owners of existing generation are, by and large, the owners of most of the new, unregulated generation in the Province. See Appendix 3.

To the extent that the Owners will also control Excess Energy and further new projects, the problem will persist. Therefore, even if PPAs are successful in constraining the Owners’ profits on their *existing* plants, there is no mechanism to control their ability to profit on the unregulated plants—and, therefore, they still have an incentive to increase the Pool Price.

For example, an Owner can plan outages in a way that increases the Pool Price, from which it can realize profits on its unregulated generation. London Economics observed:

> *[I]n 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 . . ..*

The IAT has told us that it cannot take into account generation other than that covered by the PPAs. If that is the case it means that the PPAs can at best be only partially successful in constraining market power problems, *even if the current Owners are prohibited from acquiring PPAs*. If the Owners are allowed to own PPAs—in addition to their control of non-regulated new capacity and their control of scheduling existing generation and perhaps some Excess Energy capacity—the goal of controlling market power will be totally lost.

A further concern in this regard is EPGI's proposal that the Rossdale 8 PPA will not give the buyer dispatch rights. EPCOR's reason for this is that the dispatch of Unit 8 will follow that of unregulated Unit 11. This impairs the value of the Rossdale 8 PPA and increases the problem of market concentration. An alternative would be that the Rossdale 8 PPA is dispatchable by the buyer and Rossdale 11 must be operated in order to accommodate that. Furthermore, allowing this precedent for Rossdale 8 is an encouragement for similar arrangements to be proposed by other Owners.

As outlined in Section 4, market power can be dealt with under a reg/neg approach as effectively as under the PPA approach. Therefore, unless the PPAs give customers at least as much value as they would receive under reg/neg, they will have failed in their purpose.

Value of Existing Generation Lost by Customers

The value of existing generation plants has several components.

Energy value is the difference between the embedded cost of the energy produced by the plant and the market value of that energy. To illustrate this, assume that a given plant can produce 3,000 GWh annually and that the embedded cost of that plant in the year 2001 averages $23/MWh. Assume also that the average Pool Price in 2001 will be $31/MWh. The energy value is the profit that would be realized if all the power were sold at market price—in this case, $24,000,000 (= 3,000,000 MWh x ($31/MWh - $23/MWh)). Projecting this value out over the 20-year life of a PPA gives the energy value of that plant during the PPA period. Obviously, that energy value will depend on what happens to the cost and the output of that plant over its life and what the Pool Price will be.

Hidden value is the additional value that can be created by improving operations and/or more fully utilizing existing assets. Examples of this are the use of existing infrastructure and common costs to add additional generating units. For example, as EPCOR stated in its 1997 Financial Results report:

> *There is great expansion potential at our Genesee Generating Station; its units have the lowest operating costs and highest efficiency of any in North America.*

Under Old World regulation (encompassing new as well as existing plants), these would be captured for customers by a lower cost of the additional generation as compared to generation from other sites. Failure to capture this value results in "an excess profit that would not have been earned under a regulatory environment". In the auction scenario, this would be realized from the offers made by prospective owners. See Appendix 4 for a discussion of the importance of this hidden value.

Terminal value is the value of the plant and plant site at the end of the contractual period. For example, even if a plant is decommissioned at the end of the existing PPA, the plant site probably has value in terms of access to water, transmission, transportation and coal. The evaluation and recommendation by London Economics was:

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

However, the IAT has not included any such "residual value transfer mechanisms".

Appendix 5 shows how the value of existing generation can be estimated. Clearly, some assumptions are required about future costs. The more optimistic one is about the potential for improvement, the lower the cost and the higher the value. We expect the Owners will be more pessimistic about cost reductions. Of course, that is exactly why other jurisdictions have found actual market valuations to be vastly preferable to administrative ones.

Effect of the Balancing Pool on Market Development

If the PPA auction is successful, the Balancing Pool (BP) will have a large sum of money to disburse to customers. This can, ironically, have the effect of inhibiting the development of a competitive market.

The problem is that the flowback of funds from the BP to customers can make the customers less interested in signing contracts (hedges) with new generators. Assume that the BP collects $4 billion. If this amount is amortized and refunded to customers over 20 years with a return on the unamortized portion, the refund may be 0.5¢/kWh ($5/MWh) or more. From the point of view of a customer with no contract, the actual net price of power will be then be Pool Price minus $5/MWh. Independent generators may want contracts in order to secure financing, but are not likely to forgo that much in price (relative to living off the Pool Price) simply to gain revenue stability.

Of course, reducing the amount paid to the Balancing Pool reduces this problem. But this simply means that customers are forced to give up residual value in order to benefit new generators.

Life Support for Uneconomic Units

For some units, the PPA may have the undesirable effect of prolonging the life of a unit that is uneconomic in the current market. The avoidable costs of some unit may exceed the all-in cost of new capacity. Avoidable costs include all "fixed" costs that can be reduced if the unit will not be operated, including labour, materials, transmission charges and capital expenditures. For gas-fired units with poor heat rates, it may be more economic to decommission the unit and replace it with new capacity (provided by an independent supplier), even if it is necessary to pay down the unrecovered capital cost.

Current estimates are that the all-in cost of new capacity may be as low as $20-$25/MWh. With the Owners' proposals, some existing units have avoidable costs that are higher than this level.

Will PPAs Increase New Entry?

So far, the rest of the generating world has conspicuously avoided coming to Alberta. London Economics described the situation thus:

> *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 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; (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.)*

Will PPAs Be Saleable?

More to the point, will PPAs sell for a reasonable price—that is, a price that realizes the substantial above-book value of these plants? Let us look at what some of the large players say about their strategy.

Calpine Corporation is a company that develops, acquires, owns and operates power generating facilities in the United States. At the end of 1998, it owned interests in 22 power plants in the U.S., with average capacity of 3,018 MW. New facilities and expansion projects add over 1,700 MW to this. Calpine's strategy, as described in its 1998 Form 10-K filing for the U.S. Securities and Exchange Commission, says:

> *Our strategy is to continue our rapid growth by capitalizing on the significant opportunities in the power market, primarily through our active development in acquisition process. In pursuing our proven growth strategy,* ***we utilize our extensive management and technical expertise to implement a fully integrated approach to the acquisition, development and operation of power generation facilities.*** *This approach uses our expertise in design, engineering, procurement, finance, construction management, fuel and resource acquisition, operations and*

power marketing, which we believe provides us with a competitive advantage. The key elements of our strategy are as follows:

> *Development and expansion of power plants. . . . Our strategy is to develop power plants in strategic geographic locations that* ***enable us to utilize existing power generation assets and operate the power plants as integrated electric generation systems. This allows us to achieve significant operating synergies and efficiencies in fuel procurement, power marketing and operations and maintenance.***
>
> * * *
>
> *Acquisition of power plants. Our strategy is to acquire power generating facilities that meet our stringent criteria, provide significant potential for revenue, cash flow and earnings growth and* ***provide the opportunity to enhance the operating efficiencies of the plant.***
>
> * * *
>
> *Enhancement of the performance and efficiency of existing power projects. We continually seek to maximize the power generation potential of our operating assets and minimize our operating and maintenance expenses and fuel costs. . . . We focus on operating our plants as an integrated system of power generation, which enables us to minimize costs and maximize operating efficiencies. As of December 31, 1998, our power generation facilities have operated at an average availability of approximately 96.5%.*
>
> * * *

We will consider the acquisition of an interest in operating projects as well as projects under development where we would assume responsibility for completing the development of the project. ***In the acquisition of power generating facilities, we generally seek*** *to acquire an ownership interest in facilities that offer us attractive opportunities for revenue and earnings growth, and that permit us* ***to assume sole responsibility for the operation and maintenance of the facility.***

AES Corporation is another major independent generating company,[6] with a portfolio of nearly 20,000 MW worldwide, including the 5,000 MW in the U.S. and 110 MW in Canada (in Kingston, Ontario). AES describes its business thus:

The Company also strives for operating excellence as a key element of its strategy, which it believes it accomplishes by minimizing organizational layers and maximizing company-wide participation in decision-making. AES has attempted to create an operating environment that results in safe, clean and reliable electricity generation and distribution. ***Because of this emphasis, the Company prefers to operate all facilities which it develops or acquires; however, there can be no assurance***

[6] AES has also proposed to acquire CILCORP, Inc. (formerly Central Illinois Lighting Company), an Illinois utility with \$1.3 billion in assets and 1,150 MW of coal-fired capacity.

> ***that the Company will have operating control of all of its facilities.*** (1998 Form 10-K)

Another worldwide player is **Southern Energy**, a subsidiary of Southern Company (headquartered in Atlanta). Southern's strategy is described in these terms:

> *Whether it's the plants we're acquiring in California and New York, the generation we're adding in New England, or the plants we're planning to build in the Midwest—low costs and high reliability will drive our business.*
>
> * * *
>
> *Over the next five years, we're looking to add about 20,000 megawatts of electric generation in the U.S. markets we've targeted. We've already begun those efforts with the 3,065 megawatts we're buying in California, the 1,776 megawatts we're buying in New York, and the 1,267 megawatts we've bought in New England.*
>
> * * *
>
> *In December, 1998, Southern Energy completed its $537 million purchase of 1,267 megawatts of generating capacity from Commonwealth Electric.* ***In addition, Southern Energy plans to add 685 megawatts of capacity at the plants.*** *In late 1998, Southern Energy announced the $801 million planned acquisition of 3,065 megawatts of generating capacity from Pacific Gas & Electric in northern California. Additionally, the Company announced plans to acquire from Orange and Rockland Utilities, Inc. and Consolidated Edison, Inc. in New York 1,776 megawatts of capacity for $480 million. These transactions are expected to close during 1999.* (1998 Annual Report to Shareholders)

These companies have said they want to own generating plants, not pieces of paper.

Section 3

<u>Analysis</u>

What Offers a "Reasonable Opportunity"?

Section 45.5(2) requires the IAT to determine a PPA that, *inter alia*:

> *. . . [P]rovides the owner with a* ***reasonable opportunity*** *to recover the fixed costs and variable costs of generating electricity.*
>
> * * *
>
> *. . . [P]rovides for a rate of return on equity . . . that is* ***commensurate with the risk of the owner*** *over the effective term.*
>
> * * *
>
> *. . . [I]ncludes any other terms and conditions that the independent assessment team considers appropriate.* (emphasis added)

Nowhere in the legislation does it state that the basis for compensating the Owner is the same as that used by the Energy and Utilities Board for determining compensation under a cost of service regime. In its 1999/2000 Application, TAU's capital markets witness, Mr. Falconer, says that the rules have changed:

> ***This regulatory process should be forward looking. The decision, and this process, should reflect TransAlta's new business basis under the Bill 27 and not historical regulatory concepts.***
>
> *The practice of determining an appropriate equity ratio and return on equity reflects past regulation. The circumstances are changing and this regulatory decision should reflect these new circumstances. Bill 27 suggests, in part, that TransAlta should be less regulated and that its business should be operated in a more competitive environment. Pressure is on management to provide required services yet earn a return for shareholders.* ***TransAlta must become more entrepreneurial in order to compete effectively.***

The PPA regime is clearly intended to be different than that of Old World cost of service regulation. Accordingly, the IAT is neither constrained to use Old World regulatory techniques nor should it assume that such techniques are the starting point for determining cost. In a competitive market, an Owner does not expect an income based on "return on rate base", nor can the business expect to raise prices each year at the rate of inflation. Indeed, the basic premise that deregulation of existing generation will create opportunities embodies the concept of the Owner seeking out new ways of creating value.

As discussed below, a “reasonable opportunity to recover the fixed costs and variable costs of generating electricity” cannot logically ignore (1) the potential value of the existing assets, and (2) the value of the facility at the end of the effective term. Likewise, the “risk of the owner over the effective term” must also take into account the opportunities available to the Owner that did not exist under Old World regulation. It is the *potential* of an asset that gives the Owner the opportunity to earn its return. For example, the Owner of a piece of land does not realize income from the land itself, but from the potential of the land—whether that be by farming it or building on it. Finally, the legislation clearly gives the IAT the right to include “any other terms and conditions” that it considers “appropriate”.

Operation Expenses

The Owners have all claimed that operating expenses in the future will be higher than in the past. This is summarized in the IAT’s *Technical and Cost Parameters* paper, Table 10.[7] Instead, future costs should be lower than in the past because of (1) productivity improvements and cost reductions achieved in the last few years, and (2) reasonable expectations of further efforts to reduce costs.

First, some improvements may be automatic. For example, the Owners have claimed that cycling increases the costs of Operation and Maintenance. If this is true, then it must be reflected in the period of excess capacity in the early and mid-1990s. This is another reason why the O&M expenses in the future could be expected to be lower than in the past.

In the rest of this section, we discuss a handful of examples to show the Owners’ capacity to effect such reductions. No doubt, the IAT is aware of numerous additional examples throughout the utility industry to support expectations of continued improvement.

In 1995-1996, TAU spent about $19 million on new Business Integrated Solutions Initiatives (BISI) software. Response FIRM.TAU-63(c) in the 1999/2000 GTA states that this has produced savings of $10 million annually, of which $3.7 million is for generation (1999/2000 GTA Transcript 1704).

TAU is reducing the number of coal haulers from 13 currently in use to 9, which it expects will decrease costs by $3 million annually (1999/2000 GTA Transcript 1712).

In the 1994 EEMA Forecast proceeding, APL claimed capital expenditures for “Generation Improvements”, described thus:

> *APL forecast capital expenditures during 1994 of $13,249,000 for production assets. Contained in this amount was $7,441,000 for generation improvements. In Response IPCAA.ALL-12, APL described this project as follows:*
>
> > <u>Generation Improvements</u>:

[7] ***Preliminary Review of the Owners’ Proposals for the Determination of Technical and Cost Parameters in PPAs*, 1999-Mar-31**

This project covers the annual capital improvements and betterments made to generating stations after they have been commissioned. These changes are required either to:

- *comply with safety and environmental requirements;*
- ***improve the operating efficiency or performance above that originally obtained** and thus result in reducing operating and maintenance costs;*
- *provide compliance with government regulations;*
- *or to improve hygiene or working conditions.* (Decision E93094, Page 19, emphasis added)

These should not be considered singular events; they can and will be repeated. Numerous utilities have claimed that they can reduce costs. Clearly, outsiders cannot predict what those cost reductions will be. In fact, it is the job of management to create new initiatives. While the exact quantum of improvement is impossible to specify, the IAT must take the expectation of improvement into account.

The utilities have also shown that they can make step change increases in productivity. In 1992-1993, TransAlta Utilities hired Business Design Associates (BDA) for advice on improving operations. TAU claimed that the resulting operating cost savings were $24.4 million (see PUB Decision E94095).

Aside from the savings that should be reflected in forecasts, an important point is that TAU—which, no doubt, already considered itself efficient—created an initiative to reduce costs further. TAU itself made this point in the EEMA 1995 Forecast proceeding:

> *TransAlta referenced the significant staff reduction which it underwent in 1992 and submitted that it would not have been able to undertake a second larger staff reduction within two years without a decline in customer services unless TransAlta's business processes changed.* (TAU Argument, cited in Decision E94095, Page 348)
>
> * * *
>
> *What can not in fairness be ignored is that it is precisely because of the fact that **TransAlta started off from a position of efficiency**, augmented by its 1992 early retirement program, that **further major efficiency gains could not be accomplished without significant re-organization, re-engineering and changes in business processes.*** (TAU Reply Argument, cited in Decision E94095, Page 349)

TransAlta's 1994 Annual Report stated:

> *In April TransAlta Utilities announced its intent not to increase rates to customers to at least the end of 1996, while continuing to earn a competitive rate of return for investors. To achieve this objective **TransAlta utilities set out to reduce its forecast annual operating expenses by at least $300 million by the end of 1995**. In 1994 staff were reduced by about 400 -- this was made possible through **designing more effective work practices**. (Page 10, emphasis added)*

Edmonton Power achieved a similar reduction in 1993, when it announced – immediately after the end of hearings -- that it would reduce operating costs by $8.8 million and personnel costs by $8.0 million (see Decision E93094).

In its 1991/92 General Rate Application, APL submitted evidence about improvements in its generation activities:

> *Generating Unit Reliability and Operating Quality*
>
> ***In the past, Alberta Power's generating stations have had a good record of reliability and cost effectiveness** compared with other utilities. **In order to maintain and improve this record**, the generation department has embarked on a number of activities. These include participation in company-wide initiatives to become more customer focused, such as Total Quality Management, loss management, training programs and improvements to information systems. Activities also include a number of department-specific undertakings.*
>
> * * *
>
> *3. Post Event Analysis*
>
> *A post-event analysis team approach for evaluation is being used at Alberta Power generating plants. **This facilitates continuous improvement** and establishes a framework in which a Total Productive Maintenance program can be introduced.*
>
> *4. Unit Turnarounds*
>
> *One of the department's long-term objectives is to reduce the amount of down-time required by annual turnarounds. With new maintenance practices in place, **the number of overhauls required can be reduced** from once every year (the current industry standard) to once every 18 months or longer.*
>
> *5. Fuel Quality*
>
> *Another department priority has been to improve fuel quality. **Dramatic success in this regard has been achieved** at Sheerness and Battle River stations. Customers will benefit by savings of some $400,000 a year as a result. Alberta Power is continuing to work closely with mining companies to improve the quality of delivered coal.* (APL 1991/92 GRA, Volume I, Pages 51-53, emphasis added)

CU's 1997 Annual Report stated:

> *In late 1997, APL announced that it would be streamlining its operations so that it will be better prepared to meet the challenges of a more competitive environment in the future. As a result of this process, APL has reduced staffing requirements by approximately 7%.* (Page 21)

From these examples, it is reasonable for the IAT to conclude that further major efficiency gains *can* be made. Given that independent generators clearly believe that they can implement similar "re-organization, re-engineering and changes in business procedures", the Owners should have to demonstrate why the same cannot be applied to their operations.

EPGI Fuel Costs

EPGI has added $2.84 million to the actual Genesee fuel costs. This is similar to a proposal it has made in the 1999/2000 GTA, wherein it claims that customers are receiving a benefit of this amount from the "operating benefits associated with Marion 8750 Dragline" (EPGI Evidence, Reservation Price, Fixed Fuel Cost, Page 12).

The origin of this claim is the EEMA 1994 Forecast proceeding, Decision E93094, in which the Board disallowed a portion of the dragline cost on the basis that it was uneconomic.

Genesee is one of the most expensive plants in the Province. Using EPGI's proposed numbers in the 1999/2000 GTA, the all-in cost of Genesee is about $40/MWh in the year 2000. On this basis, EPGI worries about stranded cost and wants assurance that it will not have any. Building in a phantom cost is totally contrary to the market orientation that EPGI purports to seek. This amount should be excluded from the costs in the PPA.

Allocation of Common Costs to New Units

Section 45.5(2)(d) requires the IAT to:

> *. . . [D]etermine a method of establishing the costs of the following associate facilities **that may be used by the generating unit in common with other generating units that may be constructed** at that power plant after January 1, 2001:*
>
> *(i) fuel and handling equipment;*
> *(ii) cooling water facilities;*
> *(iii) switchyards;*
> (iv) *other items;*
>
> *and of allocating those costs among all the generating units at that power plant and **those that may be constructed** at that power plant after January 1, 2001 that use the associated facilities.* (emphasis added)

This clearly states that the allocation should be done between the plants that exist and those that "may be constructed" in the future. Not actually constructed, not planned to be constructed, but those that may be constructed. While it is speculative as to what might happen in many cases, we already know that Edmonton Power plans to install new capacity at the Rossdale site and that TransAlta plans new capacity at the Sundance site. In addition, Keephills was originally planned as a four-unit plant, as was Genesee. Accordingly, the potential for new capacity at those sites exists and, according to the legislation, must be taken into account in allocating common costs.

Depreciation Expense

The IAT states that depreciation must take into account the amount of decommissioning net of salvage volume at the end of the PPA life and defines salvage value to be "scrap value after decommissioning rather than residual value on a going-concern basis" (*Technical and Cost Parameters* report, Page 27). However, if the plant is not decommissioned, there is no decommissioning cost. Moreover, if the plant is not decommissioned, then the "scrap value" is not the value of the metal, but the productive value of the machinery.

Section 6, Paragraph 8 states:

> *For capex incurred with a useful life beyond 2020, only that portion depreciated on a straight line basis up to 2020 will be included in the PPA.*

This gives the owners the ability to advance capital expenditures to a date prior to 2020 and, as a result, have a portion of the costs written off at the expense of customers rather than, as should be done, at the expense of the owner. We suggest that the criterion for inclusion in the last 3-5 years of the PPA be more stringent.

Competitiveness of Coal Plants

The *Technical and Cost Parameters* report states:

> *On a short run marginal cost basis, coal-fired thermal plant remains the most economic generation resource in Alberta. However, on a fully-absorbed cost basis, combined cycle gas turbine plant is likely to be more economical than coal thermal plant in the medium term*. (Section V, Paragraph 33, Page 24)

We consider this doubtful. Except for Milner, the coal plants have an average fuel-plus-variable cost of less than \$8/MWh. With natural gas at \$2.00/GJ, the running cost alone of CCGT plants is higher than this.

Termination of PPA

EPCOR says:

> *In our view, if the PPA is terminated for damage or destruction, the Owner should be entitled to recover its unrecovered investment in the Unit or the Plant, as the case may be, and other related costs. If the IAT is of the view that the Buyer should not bear this cost, then the payment could be made from the balancing pool.* (EPGI Preliminary Comments on Draft #2, Dated 1999-Mar-15)

This proposal demonstrates a fundamental and inequitable difference between the concept of the PPAs (at least as the Owners see them) and the sale of plants. When a plant is sold, the new Owner takes on the risk that the plant may suffer damage or destruction. Presumably, that risk is balanced by the opportunity that the new Owner has to increase the value of the plant by other means. EPGI's proposal is that it retain the opportunities related to the plant, but shove the responsibility for failure off onto customers (via the Balancing Pool).

Balancing Pool Role

We believe that the Balancing Pool's role should be that of a clearinghouse for funds, not a financial guarantor of operations.

The owners have posited and several circumstances under which they would be entitled to payments from the Balancing Pool—e.g., plant damage/destruction or PPA termination. The principle here seems to be that the Balancing Pool should back up the Owner for anticipated negative developments. If this principle is accepted—and we do not believe it should be—then it should be a two-way street. It is only fair, them, that the owners should compensate the Balancing Pool for anticipated positive developments. For example, if new capacity is developed at the site beyond that considered in the initial allocation of costs, the Owner should compensate the Balancing Pool for the common costs fairly allocable to the new capacity. (In order for this to be self-policing, the compensation must be higher than for amounts anticipated in the IAT's initial calculations).

The IAT's 1999-Apr-12 paper—"*Backstop" Role of the Balancing Pool*—contemplates that the Balancing Pool would be required to take over the role of the buyer in the event that the Buyer exits from the terms of the PPA. This has the potential to create undesirable incentives for Owners and Buyers and unnecessary costs for customers. Similarly, the IAT contemplates that the Balancing Pool "should provide some financial support in certain specific instances", such as *force majeure* and additional costs incurred as the result of a Change in Law. Finally, in the event of destruction (Article 15), the IAT says that "either the Owner or Buyer can decide that . . . the PPA ceases to be a worth while arrangement and can elect to terminate the PPA".

EPGI has submitted that:

> *In our view, if the PPA is terminated for damage or destruction, the owner should be entitled to recover its unrecovered investment in the Unit or the Plant, as the case may be, and other related costs.* (EPGI 1999-Mar-21)

We see two problems with this proposal. First, whether a unit is "damaged" to a significant extent is more a financial than a technical issue. Repairing damage may be quite feasible technically, but have the effect of reducing the Owner's return. The Owner may then decide that it is more profitable to declare the plant "inoperable" and collect a full return on the remaining assets from the Balancing Pool rather than incur the cost of repairing the unit and thereby receive a reduced return. This was demonstrated in the matter of APL's Battle River 1&2 units. They could have been repaired, but APL's evaluation was that the cost of repair exceeded the value of the energy to be produced. Appendix 6 contains some more background on the Battle River 1&2 experience. A statement by APL highlights the problem:

> *It had been established that it was not economic to life extend Units 1 and 2.* ***Under these circumstances, any unit approaching the end of its life may suffer a failure that is uneconomic to repair just like Units 1 and 2****. Application for*

recovery to the TSR is a probable result that an owner would choose. (Group-APL.19, emphasis added)

Second, there must be a requirement for mitigation of costs, of which one option should be selling the asset. If a plant is damaged, it may still have significant value, even though the owner declares it to be destroyed. Other potential owners may consider that the unit can be repaired at less cost and/or the site may be attractive for redevelopment. The Balancing Pool should not be required to make any payments until the owner has made all attempts at mitigating expenses, including reducing fixed operating costs and selling the assets.

EPGI suggests:

> *Further, in our view, it is not appropriate that the consent of the Buyer be required to terminate the PPA if the Unit or Plant is destroyed to the extent the Unit is incapable of generating Electricity as proposed in the draft PPA. The determination as to whether the Unit or the Plant can be economically repaired, replaced, rebuilt or restored or the PPAs should be terminated should be made having regard for the balancing pool's economic interest as opposed to that of the Owner or the Buyer.* (EPGI Preliminary Comments on Draft #2, 1999-Mar-15)

What EPGI does not discuss is *how* to take into account "regard for the balancing pool's economic interest". In this respect, the Balancing Pool's economic interest is, in reality, the interest of the consumers in the Province. No form or mechanism is provided by which the consumers can make the decision.

Incremental Capacity

EPGI wants that:

> *The Owner should be able of* [sic] *develop and implement Incremental Capacity without requiring the consent of the Buyer if the Buyer's rights in relation to the Committed Capacity under the PPA being* [sic] *appropriately protected.* (EPGI Preliminary Comments on Draft #2, 1999-Mar-15)

This formulation of the Owner's flexibility raises an interesting question. The example may seem far-fetched, but it illustrates the one-sidedness of the Owner's view. What if the Owner begins to develop Incremental Capacity at a plant site, but, through an accident in the process, damages some of the existing capacity? Had the process been completed without incident, the Owner would receive all the benefit. However, the damage of the existing capacity would, in EPGI's view, require the customers (through the Balancing Pool) to bear the cost of the lost capacity.

Capital Structure

Market evidence suggests that the 40% equity ratio proposed by the IAT is far too high. New *merchant* plants—that is, plants without contractual commitments—can probably be financed with less than a 40% equity ratio. For example, a new merchant plant built recently in Texas by Central and SouthWest (a utility) and Phillips Petroleum had an 80/20 debt/equity structure. A plant being built in Nevada by Houston Industries and Sempra

Corporation *with no underlying contracts for steam or power sales* will have a 60/40 capital structure. A pure merchant plant acquisition in New York will have less than 30% equity financing (see Appendix 7). In the Old World, non-utility generation (NUG) projects with contracts had as little as a 10% equity ratio. Calpine Corporation (mentioned above) has a debt/equity ratio of about 79/21:

> *. . . [W]e have substantial debt that we incurred to finance the acquisition and development of power generation facilities. As of December 31, 1998, our total consolidated indebtedness was $1.1 billion, our total consolidated assets were $1.7 billion and our stockholders' equity was $287.0 million.* (1998 10-K Report, Page 19)

If a plant without any contractual commitment for fixed cost coverage can achieve sufficient protection with a 40% equity ratio, plants covered by PPAs require much less.

Cost of Capital

Similarly, the return on equity proposed by the IAT is too high. We first observe that the Owners' submissions uniformly claim that the risks under the PPA regime are higher than currently. This, however, ignores the opportunities for higher returns that are produced by deregulation.

Before arguing the point about relative risks, let us look at the increased cost using the IAT's tentative numbers. If the risks of PPAs are assumed to require a 40% equity ratio and an increase of 100 basis points in equity return, the increase in return and taxes on $3.8 billion of net investment is about $25 million annually.

Corroborative evidence comes from the treatment of stranded costs in other jurisdictions. Where the stranded (above-market) cost is securitized, it has been financed by bonds with interest rates lower than 6%.

To support its recommendations on capital structure and interest coverage, APL has looked at three "stand-alone regulated generation companies that sell their output primarily to distribution affiliates under long-term contracts". The three are: Allegheny Generating Company; Canal Electric; and New England Power (APL Response IAT-APL-21, Dated 1998-Dec-21). Of these three, two have already been sold in order to address market power and cost mitigation concerns. New England Power was part of the New England Electric System, which decided to sell all of its generation to other companies. These plants fetched a price that was 50% higher than book value. Moreover, the NEP plants no longer have guaranteed long-term contracts with the formerly-affiliated distribution companies. The same is true of Canal Electric.

Excess Energy

We agree with the IAT's determination that Excess Energy should be offered by the Buyer, not the Owner. Both EPCOR and TAU take issue with the IAT's approach to the treatment of Excess Energy. Both Owners consider that the IAT has no authority to determine the offers for Excess Energy. One issue in this respect is what the legislation says. Another is how the treatment of Excess Energy can affect other issues, such as market power.

Section 45(5) says:

> *If the generating unit produces more electric energy than is anticipated in the power purchase arrangement that applies to it, the owner of the generating unit is entitled to the benefit associated with the exchange through the power pool of the excess electric energy produced, in accordance with the regulations, notwithstanding that the right to exchange the electric energy may be exercised by the purchaser of the power purchase arrangement pursuant to subsection (3).*

This states that the Owner is entitled to the "*benefit . . . of the excess electric energy produced . . .* notwithstanding that the *right to exchange electric energy may be exercised by the purchaser*".

How should Excess Energy be defined? The IAT's preliminary proposal is that it is energy over and above the MCR of the unit. However, inasmuch as units have regularly produced at levels higher than MCR, this is too low. We suggest that Excess Energy be defined as any amount over and above the maximum output of a unit heretofor. This will not deny the Owners the benefit of Excess Energy, inasmuch as the higher output will be reflected in the Availability Incentive Payment.

Setting the Bar

How much output can we reasonably expect from these units? The Owners have submitted their estimates. From the last three years, we know that these estimates are extremely conservative. A good example is EPGI's Genesee unit. EPGI apparently considers that it will not be able to perform as well under the PPA as it has under current regulation. In the 1996 GTA, EPGI estimated that Genesee could produce 6,070 GWh. The actual output was 6,345 GWh (equivalent to 6,327 in a non-leap year). For 1996-1998, Genesee has averaged over 6,300 GWh, a level far higher than EP's forecasts.

One interesting aspect of this is that EP's Negotiated Settlements for 1997 and 1998 included deferral accounts to capture 75% of the deviation of actual from forecast. In the current GTA hearing, EPGI has said that such deferral accounts "dull" EPGI's incentives. Imagine, then, how much better EPGI could have done without deferral accounts.

Both EPCOR and APL want the expected output reduced to account for the asymmetry effect. EPCOR suggests that:

> *EPCOR notes, however, that using market-based incentives requires recognition of the pool price asymmetry effect on the Owners* [sic] *financial position. Given that the industry supply curve is upward sloping, pool prices on average are higher when a unit is unavailable than when it is available. This means that setting the Availability Target at the expected level of output, under a market-based incentive scheme, will not leave the Owner financially neutral. The average pool price when the output from the generating unit exceeds the Availability Target will be less than the average pool*

price when output from the generating unit is less than the Availability Target. (EPCOR Utilities Inc. Comments, 1999-Feb-05)

APL makes a similar point:

> *. . . [A] forced outage of a unit, particularly one with large capacity, can itself cause a large price increase. This causal relationship is not symmetric in its effect on price and adds to the owner's risk.* (APL Letter to IAT, 1999-Feb-24)

The statements ignore the effect of one plant's outage on other plants. Obviously, if the outage of a large unit drives up the Pool Price, the Owners of all other large units benefit at that time. And, indeed, this has happened. The actual asymmetry effect observed heretofore has been much less pronounced than claimed by the utilities. In fact, in some cases, units have received, on average, more during periods of high availability than they have given up during periods of low availability (see Appendix 8).

EPCOR goes on to suggest:

> *One solution is to decrease the Availability Target sufficiently to leave the Owner financially neutral. The amount of reduction required can be determined through hourly production simulations.* (EPCOR Utilities Inc. Comments, 1999-Feb-05)

This is a reprise of the arguments used to set the Unit Obligation Amounts in the current legislated hedges—which have proven to be way off the mark. As background, the UOAs were set so that surplus/shortfall amounts were expected to be zero in the "year of balance", expected to be 1999 or 2000. In fact, the net surplus of both TAU and EPGI has increased every year, exactly contrary to the modeling predictions.

Cycling

Cycling appears to be an area where the owners have discovered new costs. For example, APL states:

> *For most of the units in Alberta, it would be technically possible to cycle them on and off twice each day. In some cases due to turbine design, differential expansion limits would prevent this.*
>
> *However, we believe this mode of operation will significantly reduce both the life of the units and their reliability, and require a large increase in maintenance expenditures.* ***Therefore, APL cannot accept a mode of operation that synchronizes and desynchronizes twice in 24 hours without a significant change to cost and performance required. This cannot be estimated without a major design, reliability and cost impact analysis done on each unit.***
>
> *The units were not designed for cycling and, therefore, do not have the necessary features such as adequately sized start-up vents, turbine by-pass systems, or other means that would allow boiler steam temperatures to be closely matched to turbine metal temperatures during hot start-ups. Frequent start-ups of this type, and the repetition of large thermal stresses on the turbine rotors, casings, and valve bodies,*

> *will lead to initiation an dpropagation of cracks. Similar concerns exist for boiler drums, headers, high energy piping systems, pumps, etc.*
>
> *Although,* [sic] *it may be possible to retrofit units with some of these systems to accommodate cycling, our opinion is that this would never be economic.* (APL Response IAT-APL-8, emphasis in original)

Oddly enough, the utilities never mentioned these costs when they proposed plant expansions in the Old World that resulted in excess capacity. The additions at Sheerness and Genesee resulted in very high reserve margins, which must have bumped some of the higher running-cost plants into cycling mode. Thus, APL's claim that the plants cannot cycle "without a major design, reliability and cost impact analysis done on each unit" seems rather overblown.

Auction and Ownership Rules

Section 45.93(2) states that:

> *The independent assessment team shall recommend to the Minister rules relating to the holding of an auction under this section, including*
>
> *(a) the setting of limitations respecting*
>
> *(i) the number of power purchase arrangements that may be purchased by one purchaser,*
>
> *(ii) the types of power purchase arrangements that may be purchased by one purchaser, and*
>
> *(iii) who is eligible to bid on power purchase arrangements,*
>
> *(b) the setting of conditions and reserve prices, and*
>
> *(c) the determination of any other matter relating to an auction.*

As noted by London Economics, in other jurisdictions that were tight on capacity, incumbents were not allowed to develop or take part in the development of additional new capacity. That restriction has not been applied here. However, the problem of continuing market power will only be aggravated by allowing Owners to purchase PPAs.

EPCOR would characterize this recommendation as a "knee jerk" approach and says:

> *There must be very clear and bonified reasons as to why any restrictions would only apply to some market participants and not all.* (EPCOR Utilities Inc. Comments, 1999-Feb-05)

We think the reasons are very clear. Obviously, not all "market participants" are equal in this process. One stated purpose of the PPAs is to disperse market ownership. The IAT should, therefore, definitively state the problem and the restrictions.

Transmission Tariffs

For 1999, TAU, APL and EPTI have filed for $100 million of transmission additions. Their total depreciation provision was approximately $90 million, giving a net increase in transmission plant of approximate $10 million. The transmission administrator has indicated that investments in system reinforcements need to increase in current levels. In their recent Transmission Development Plan, EAL stated:

> *Capital investment in transmission system reinforcements over the last several years has been at historically low levels. This low level of system investment has had the beneficial effect of increasing utilization of existing transmission facilities, but it is not sustainable in the longer term without jeopardizing system security and reliability.*

The additional system investments appear to be in the order of $30 million per year. This suggests a net increase of $40 million per year in transmission plant or roughly $6 million per year in revenue requirement on a base of $400 million of wires costs. This increase is roughly in line with load growth suggesting relatively stable transmission tariffs in the next few years.

Issue 1. Scheduling and Dispatch Protocols

Issue:

Any PPA must identify in clear terms what rights and obligations TransAlta and the Buyer have in setting Maintenance Schedules and Daily Dispatch Schedules.

TransAlta Proposal

TransAlta proposes that it have sole discretion on setting and revising maintenance schedules. The Owner will provide the Buyer with a Maintenance Schedule and provide the Buyer with an opportunity to request a change to the schedule, provided that the Buyer be responsible to negotiate with other Buyers if the requested change causes a change to the Maintenance Schedules of generating units that are contracted to the other Buyers.

The Buyer has the right to set Daily Dispatch Schedules, subject to some restrictions.

Defining the rights and obligations does not preclude the Owner and the Buyer from negotiating alternate arrangements that are in the best interests of both Parties.

Underlying Concerns:

As Owner and operator of the asset, TransAlta must insure that it can manage its operation as indicated below.

Planned Maintenance (Turnaround)

Planned Maintenance (Turnaround) - On a regular basis the unit is taken off line to do maintenance repairs and replacements that are not possible on line. These outages occur in some form on a yearly basis.

- TransAlta has in place processes, tools and equipment, and staff and contractors, which optimize the cost of performing maintenance on its generating units and which enable it to control the quality of the workmanship. TransAlta should not be forced to increase its costs or reduce the quality of the workmanship by relinquishing the maintenance scheduling responsibility to the Buyer. A turnaround takes months of preplanning to ensure an efficient, safe turnaround. A sudden change in the schedule that moves the turnaround forward may require that the unit be shutdown without the proper planning and preparation for the turnaround. The effectiveness and productivity of the turnaround will be reduced.

For example:

- ♦ TransAlta currently uses the same tools and equipment for all of its units. Having two or more units scheduled off would require it to acquire additional tools;
- ♦ TransAlta does not have adequate physical space or lifting crane capacity to simultaneously perform maintenance on two units in a given plant;

- ♦ TransAlta currently uses the same full time and temporary staff to do Planned Maintenance for all of its units. Having two or more units scheduled off would require it to hire additional staff to perform the work as well as additional management and supervisory staff to supervise the work. The additional supervisory staff would need to be familiar with the unit, and therefore it would not be practical to employ contract staff for these positions;
- ♦ TransAlta currently contracts in excess of 200 skilled tradespersons to do Planned Maintenance on a single generating unit. Having two or more units scheduled off would severely strain the ability of the skilled trades market in Alberta to provide the necessary quantity and quality of contract staff;
- ♦ TransAlta currently schedules maintenance on its units so that plant auxiliaries, such as cooling ponds, boiler water treatment facilities, etc. can adequately supply the plant requirements without causing derates or extensions to outages to other units in the plant;

- Large capital projects, such as turbine replacement, can take up to three years to schedule and implement. The schedules for this work have to be set early and be open to changes if the delivery schedules of the replacement components change.

For example, bolts that are on the high pressure, high temperature turbines need to be replaced on a frequency determined by hours of operations and number of startups. This ensures against catastrophic failure of equipment and injury to personnel. These bolt replacements are scheduled on annual overhauls. The bolts are purchased and brought to site on a just in time basis for the overhaul time. If the original overhaul is moved and the parts, such as these bolts, are not available for use the unit may be required to run using bolts that are past their safe life.

- TransAlta must be able to adjust the Planned Maintenance Schedule for a generating unit if, as a result of a Forced or Scheduled Maintenance, it proves to be more effective, usually by reducing the overall outage time, to proceed with Planned Maintenance work immediately.

There are times where a unit may be scheduled for an annual overhaul, and some time before the annual overhaul is to commence, an equipment failure may occur that requires the unit be taken off line. If the outage required for the repair is beyond the normal forced outage length, and the parts availability and other variables are favourable, the annual overhaul may be started early and combined with the equipment failure repair. This gives TransAlta the opportunity to reduce the number of outages, startups, and costs for unit overhaul.

- TransAlta must be able to overlap the maintenance of units that share common facilities which must be maintained, such as the exhaust stack that is common to two or more units.

The design is such that two units discharge into one stack. On a regular basis the internal stack components must be inspected and possibly repaired. This requires that both the generating units using that stack be shutdown and off line.

- TransAlta must be able to schedule Planned Maintenance in the appropriate season. A spring or summer Planned Maintenance schedule could lead to the unnecessary spilling of water at hydro plants. A winter Planned Maintenance schedule at a thermal plant could require costly supplemental heating to maintain adequate ambient temperatures within the plant and may prevent some maintenance, such as emission control device maintenance, from being done at all.

Scheduled Maintenance

Scheduled Maintenance - Outages or derates that are required due to equipment failure. These outages are needed when the repair cannot be delayed until the next forced outage takes the unit off line or until the next annual overhaul. There may be a risk to personnel safety or increased damage may occur to the equipment if the maintenance is delayed for too long into the future.

- The concerns about tools and equipment, staff and contractors, and plant auxiliaries, which apply to Planned Maintenance also apply to Scheduled Maintenance.
- Personnel safety, equipment safety, and forced outages to other of TransAlta's generating units require schedules to be modified quickly in the event that TransAlta can protect its employees, its equipment, and can manage the maintenance costs for all of its units.

Forced Maintenance

Forced Maintenance - An outage where the unit is taken off line or derated within 24 hours of an equipment problem being identified. This may occur on an instantaneous basis if protection trips actuate to protect personnel and equipment, or there may be a controlled shutdown or derate of the unit within a few hours due to equipment failure that will not allow continued operation.

The failure of some equipment may cause the unit to be reduced in load but not necessarily taken off line. Major auxiliaries on the units are sometimes duplicated so that it takes both to run at full load. If one of the duplicate components fails, it is still possible to run at half the rated load.

- The events which lead to forced maintenance cannot be predicted, and therefore TransAlta cannot give the Buyer rights to schedule forced maintenance.

Daily Dispatch

Dispatch - The generating units are dispatched down or up in output to meet the load demands in the system.

- The Buyer has the right to set and modify the daily dispatch schedule which meets its' needs to supply the energy and ancillary services markets. TransAlta has environmental and operational concerns that restrict certain dispatch levels or unfettered adjustments to dispatches. These include:

- Environmental licensing and compliance which can effect the length of time that it takes to shutdown or startup a thermal generating unit or the timing and volume of water releases from hydro generating units;
- Minimum loading limits on thermal generating units and unstable operating levels on hydro generators; thermal generating unit differential expansion and contraction, and “on - off” heat cycling effects on turbines and boilers;

In boilers where the coal is burned, there is a minimum load or volume of coal that can be burned. Below this level the flame or burning becomes unstable. The instability can cause the flame to extinguish and relight in the form of an explosion. Personnel and equipment damage is very possible in this type of occurrence.

Putting units on and off is not the same as turning a light switch on and off. To start a generating unit equipment must be subjected to high temperatures (up to 1005-2000 degrees F) and pressures (up to 2500 pounds per square inch). When a unit is taken off line, these temperatures and pressures are normally reduced to zero pressure and ambient temperatures. Thus, taking a unit on and off line causes a cycling effect. This cycling stresses metals and reduces the useful life substantially. A reduced life means that the inspection schedules and repair / replacement costs would both increase meaning higher costs of production and lowered outputs.

- Startup and shutdown gas and electricity demand ;

There is a limit to the amount of gas that can be drawn through a the gas line that serves our thermal units. If the startups and shutdowns of the units at our three major stations in the Wabamun lake area are not coordinated, the gas excess draw on the supply line can create startup delays.

The contracts for the gas and electricity used for startups have costly demand ratchets which would be impacted if the startups are not coordinated.

- Additional staffing required for startups and shutdowns;

Our current shifts and sizes of crews are geared toward base load operations. Major changes to the number of startups and shutdowns of the units will increase costs for manpower.

- That plant auxiliaries, such as boiler water treatment facilities, external station service, etc. can adequately supply the plant requirements for start-ups and shutdowns;

  Equipment such as the water treatment plants which supply water and ultimately steam for the generation process have been built and designed for base load type of operations. While the generating units are running, the water is recycled and reused so there is little waste. Taking units out of service and putting them back on line causes much more water waste due to water purity concerns. Therefore in a given station the capacity of the equipment supplying water has been designed to supply the operating units and some startup capabilities for units that are off line. The increased water use for more frequent outages will tax this supply and cause delays in startups and coordination problems within a station if there are excessive outages.

Alternatives to TAU Proposal:
TransAlta is not currently proposing an alternative to the Scheduling and Dispatch alternative it has proposed. We would look forward to working with the IAT to find other alternatives that could meet the overall objectives, while taking care of TransAlta's concerns.

Issue 2. Force Majeure

Issue:

TransAlta has proposed a PPA with the Balancing Pool taking the risk of force majeure events. During a force majeure event a unit would not be available as contracted but the capacity price for the unit would continue to be paid to the Owner. In TransAlta's proposal the Owner would be subject to market penalties during periods of unavailability, except where such periods are the result of force majeure. Conceptually, it is envisioned that the force majeure risk will be passed off to customers who now take this risk under the legislative framework (Temporary Suspension Regulation). The IAT has stated that in force majeure events the risk of covering fixed costs be carried by the Owner and have suggested in meetings with TransAlta that the Owner insure for force majeure events.

TransAlta Concerns:

- Under current law, a force majeure regulation (Temporary Suspension Regulation) exists wherein customers continue to pay generator fixed costs during bona fide suspension (force majeure events). It was developed as a risk sharing arrangement agreed to between customers and Owners in a public process in 1995. Prior to this time, the customers would have paid costs of force majeure events, through rate reopeners if necessary.

- Many force majeure events simply cannot be insured against. The types of events that can be insured against are flood, earthquake, storm, fire, accident, sabotage, etc. The types of events that cannot be insured against are strikes, lockouts or other labor disputes, civil disturbance, war, epidemic, regulatory or governmental action, court restraints, etc. Certain force majeure events or risks such as equipment breakage, lack of supplies or fuel may or may not be insurable depending on whether an insured peril caused the event.

- Requiring an Owner to carry force majeure risk is a fundamental change in risk profile from today's regulatory framework. Imposing on Owners the exposure to significant events beyond an Owner' control is unfair. Determining appropriate compensation for such exposure is difficult or impossible, as indicated by the lack of an insurance alternative.

- TransAlta believes the lowest cost indemnification should be sought and that the lowest cost alternative is to leave the force majeure risk with the customer.

Alternatives:

- As proposed by TransAlta in its submission of August 31, 1998, the Balancing Pool would hold the full force majeure risk through the use of the Owner-BPC-Buyer market structure.
- If a contract structure of Owner-Buyer is chosen, one of the three following options should be selected:

  Option 1: a legislated arrangement which shifts all force majeure risk, as currently established, to the BP; or

  Option 2: a combination of:

    - the Owner including the full cost of insurance to cover insurable items (flood, earthquake, storm, fire, accident, sabotage, etc.); and,

    - a concurrent legislated arrangement which shifts to the balancing pool the obligation to cover fixed costs of generation during events which are uninsurable (strikes, lockouts or other labor disputes, civil disturbance, war, epidemic, regulatory or governmental action, court restraints, etc.);

  or

  Option 3: a liability cap be placed in law and then the Owner would carry insurance as available plus would build into the PPA cost structure provision for levies to create self reserves.

TransAlta Preferred Outcome:

TransAlta believes the most cost efficient alternative for the customer is to leave the risk with the customer. TransAlta bases this belief on its history of efficient generation performance over several decades without a single "force majeure" declaration or request to reopen rates to pay for a force majeure event.

The arrangement Owner-BPC-Buyer, as proposed by TransAlta in previous submissions, accomplishes this outcome. Either Option 1 or Option 2 could provide a similar outcome.

Issue 3. Change in Law

Issue:

TransAlta has proposed a PPA with the Owner being indifferent to changes of law. The Buyer would get the benefit of changes of law that reduce the generator's costs and would pay for increased costs resulting from a change of law, all as advised by the Owner. If a change of law resulted in the Owner being unable to perform, a force majeure event would be triggered for the Owner. At this juncture TransAlta sees a carbon tax or corollary environmental levy on coal being the biggest risk of a change of law. Such a risk is fundamental to the economics of thermal generation in Alberta and would in all likelihood be passed through the Buyer to the consumer as neither the Owner nor the Buyer could afford to retain such a fundamental risk.

It is TransAlta's understanding that the IAT supports this position.

In the case a change in law of sufficient magnitude to render a unit or plant uneconomic, TransAlta has proposed that a mechanism exist whereby the Owner's unrecovered capital costs be paid out and the unit or plant set clear of regulation.

TransAlta Concerns:

> TransAlta's main concern is that there be no major change from past treatment for change in law. TransAlta has always flowed through changes in cost structure resulting from changes in law to the consumer. Examples are environmental standards (adding precipitators, cooling ponds, reclamation), dam safety (spillway upgrades) water rentals for the hydro plants, site decommissioning costs and property taxes.
>
> The Owner must have some security that any unrecovered sunk costs be paid out.

Alternatives:

In TransAlta's opinion, there are no fair and rational alternatives to the change of law clause as proposed by TransAlta.

TransAlta Preferred Outcome:

Status quo as per TransAlta PPA.

Issue 4: Buyer Credit Risk

Including a Buyer in the process from the Generator to the Power Pool creates an additional entity for which a risk of default exists. A process must be put in place that ensures that customers continue to receive the energy produced by the unit and TransAlta (an Owner) gets paid, even if a Buyer default occurs.

TransAlta Concerns:

- the default of a Buyer should not impact the Owner's rights to be paid under the terms of the PPA;
- a mechanism must exist to ensure that any unit can stay in operation through any period from when a Buyer has defaulted to when a new Buyer is in place.

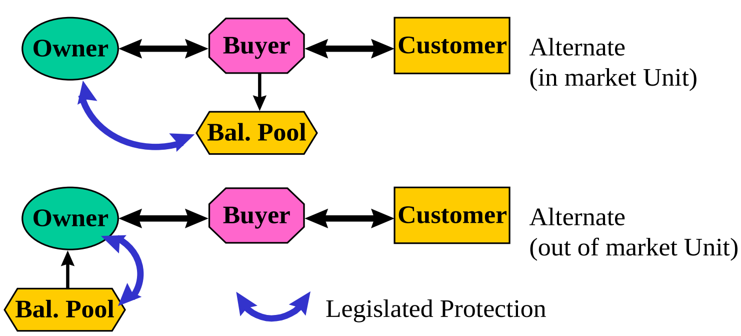
Alternatives:

Alternative 1: TransAlta has proposed a market model in which the Balancing Pool Company is the contract counterparty for both the Owner and the Buyer. In this model, the BPC holds the risk of Buyer default.

A second alternative (**Alternative 2**) which would be acceptable to TransAlta, that fits in the Commercial contract model of Owner - Buyer, follows:

It is envisioned that an administrative function be performed by the Balancing Pool, and that such function should be no more onerous than the functions already contemplated for the BP in the EU Act.

Model:



Functioning of Alternative 2

a) Protection mechanism

- Given the PPA is between the Owner and the Buyer, a law is enacted (legislative protection) that contains a clause which, on Buyer default, the contract obligations are automatically transferred to the BP including any outstanding accounts receivable. This would be a temporary measure until such time that a new Buyer can be installed.
  - Owner continues to operate unit
  - Owner dispatches the unit on a temporary basis
  - BP receives the pool price revenue
  - BP pays Owner per the terms of the PPA

This mechanism maintains the philosophy that the customers retain the cost obligation and receive the production from regulated generation until the end of the effective term.

b) The process which would be implemented on Buyer default is as follows:

- Contract obligations transfer to BP
- BP puts contract up for re-auction
- The new Buyer is installed and the contractual relationship between TransAlta (an Owner) and Buyer is reestablished
- If, in the opinion of the BP, the unit is out of the money on a going forward basis, the BP has the right to exercise its unilateral Termination clause (per the TransAlta PPA contract form Section 17.5(b)), pay out the Owner and cut unit free of regulation.

Other alternatives:

Two other alternatives which shift the risk management obligation from the customers to either the Owner or the Buyer could be as follows. For each of the alternatives, the Owner would require legislative guarantees that the BP would make up the remaining exposure if the auction was not completed within one year.

Alternative 3 - Risk managed by TransAlta (an Owner):

This assumes that neither the BP nor the Buyer accepts any of the risk except that which is mentioned in the preceding paragraph. The plant Owner could purchase credit risk insurance to mitigate the risk and include the cost of such insurance in the respective PPA. The price of such insurance would depend on the credit rating of the Buyer and the extent to which the Buyer is obligated under the terms of the PPA.

Pros: Managed by Owner.

Cons: Increased cost to customer in that cost will be reflected in the associated PPA.

Some form of insurance cost indexation would be required.

Issue 5. Parties to the PPA
Generator and BPC; BPC and Buyer

Issue:

TransAlta has proposed a framework in which the PPAs are contracts between the Generator and a Balancing Pool Company (BPC). This essentially replaces the regulatory contract in terms of traditional risk while altering the regulatory contract in terms of the long time frame and the potential for significant incentives to the Generator for efficiencies and new capacity additions. The availability and output of the generating unit up to the committed capacity would be contracted to the BPC by agreement between the Generator and the BPC. At the same time the BPC would contract with a Buyer for the same unit output. The BPC - Buyer contract would be structured with a different covenant pattern than the Generator - BPC contract, being in all likelihood more closely aligned with purely commercial contracts.

The BPC would retain any obligations and risks that would not be passed onto the Buyer. In our view these retained obligations and risks would include the obligation to continue paying capacity charges during a Generator force majeure event and the risk of Buyer credit defaults and insolvency throughout the term.

Because the term of the regulatory compact for a generating unit is essentially until the end of the base life period, life extension period or 2020 (whichever is earliest), the term of the Generator - BPC contract would conform to this time period. Owing to the history of stability in both the utilities and electricity supply under decades of regulation in Alberta, it is anticipated that there would be few terminating events in the Generator - BPC contract. Briefly, in TransAlta's proposal the BPC could terminate if the Generator became insolvent and the Generator could terminate if the BPC did not pay contract prices or became insolvent. Defaults in performance by the Generator would be subject to market penalties in the incentive formula and would be subject to cure periods with diligence. In addition the BPC could terminate and pay out the contract if the plant was out of market.

However, for BPC - Buyer contracts, default and termination might be structured differently as we anticipate a different risk profile for the competitive electricity marketing sector. The BPC might be required to terminate for Buyer payment defaults or failures to meet financial tests and to re-contract with other Buyers during the 20 year period. The Generator would be insulated from this credit risk and there would be no need to agree to a conversion of the contract to a financial instrument with the BPC on Buyer default.

TransAlta believes that the foregoing is an easy way to achieve two perhaps parallel goals of the PPA process as envisioned by the legislation and the IAT - to replace the regulatory compact for units at the earliest of the end of their base life, life extension period or 2020, and to introduce power marketers to the Alberta marketplace on largely commercial terms.

The following illustrates the respective major obligations and allocations of risk as among the Generator, BPC and Buyer.

Generator

Major Obligations:	⇒ provide committed capacity and energy up to committed capability at the prices set in the PPA ⇒ meet standard of good operating practice
Risks Held:	⇒ capability and availability risk at power pool prices (limited by risk collars and force majeure protection) ⇒ cost variation not covered by indexing or flow-through ⇒ capital infusion risk to maintain committed capacity

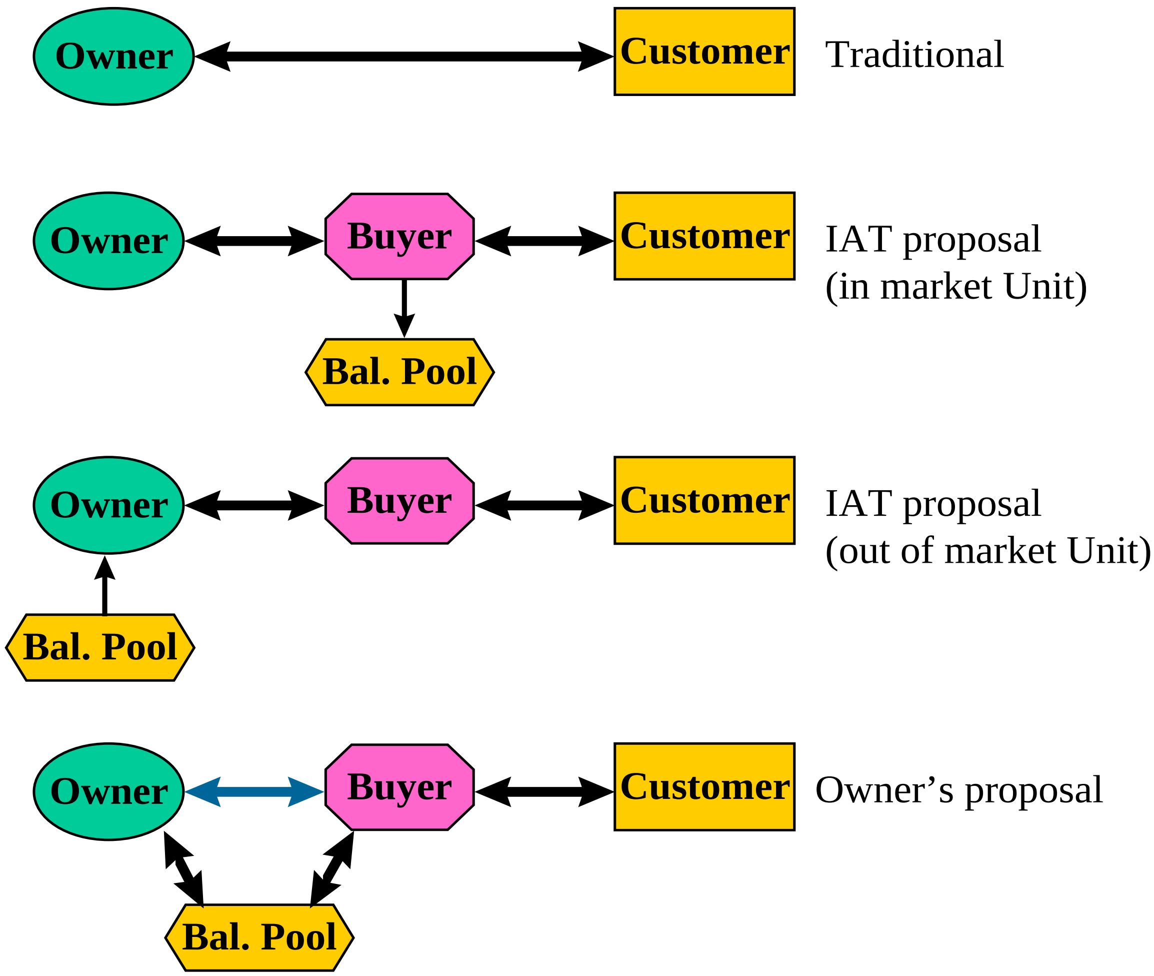
BPC (on behalf of customers)

Major Obligations:	⇒ retain "default" ability to dispatch and exchange through pool ⇒ maintain solvency of the BP (if BP is negative, acquire difference from customers) and transfer any residual value from PPA auction process to customers ⇒ reauction PPA if Buyer defaults
Risks Held:	⇒ payment of capacity price during Generator force majeure events ⇒ Buyer default and credit problems

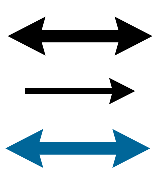
Buyer

Major Obligations:	⇒ pay contract prices (capacity, energy, additional and incentive) ⇒ maintain ability to dispatch and exchange through power pool ⇒ maintain good standing as wholesale marketer ⇒ maintain credit requirements
Risks Held:	⇒ pay for increased costs arising through change of law ⇒ business interruption caused by generator default in production ⇒ pool price risk ⇒ amount of committed capacity actually selling into the market ⇒ PPA price variation caused by indexing and flow-through

Counterparty Relationships



Where:



Contractual link

Fixed payment arrangement

Operational link

Alternative Mechanism

The following illustrates an alternate mechanism indicating respective major obligations and allocations of risk. TransAlta could support such an alternative given that the concerns identified in its Issue Papers on Credit Risk, Force Majeure and Change of Law were satisfactorily addressed. It must also be recognized that this type of market structure is likely contingent on the marketability of a 20 year PPA in the auction process.

Generator

Major Obligations:
- ⇒ provide committed capacity and energy up to committed capability at the prices set in the PPA
- ⇒ meet standard of good operating practice

Risks Held:
- ⇒ capability and availability risk at power pool prices (limited by risk collars and a limited force majeure protection)
- ⇒ price variation not covered by indexing or flow-through
- ⇒ capital infusion to maintain committed capacity
- ⇒ insurable events: flood, earthquake, storm, fire, accident, sabotage, etc. (full insurance costs included in PPA price)

Buyer

Major Obligations:
- ⇒ pay contract prices (capacity, energy, additional and incentive)
- ⇒ maintain ability to dispatch and exchange through power pool
- ⇒ maintain good standing as wholesale marketer
- ⇒ maintain credit requirements

Risks Held:
- ⇒ pay for increased costs arising through change of law
- ⇒ business interruption caused by generator default in production
- ⇒ pool price risk
- ⇒ amount of committed capacity actually selling into the market
- ⇒ PPA price variation caused by indexing and flow-through

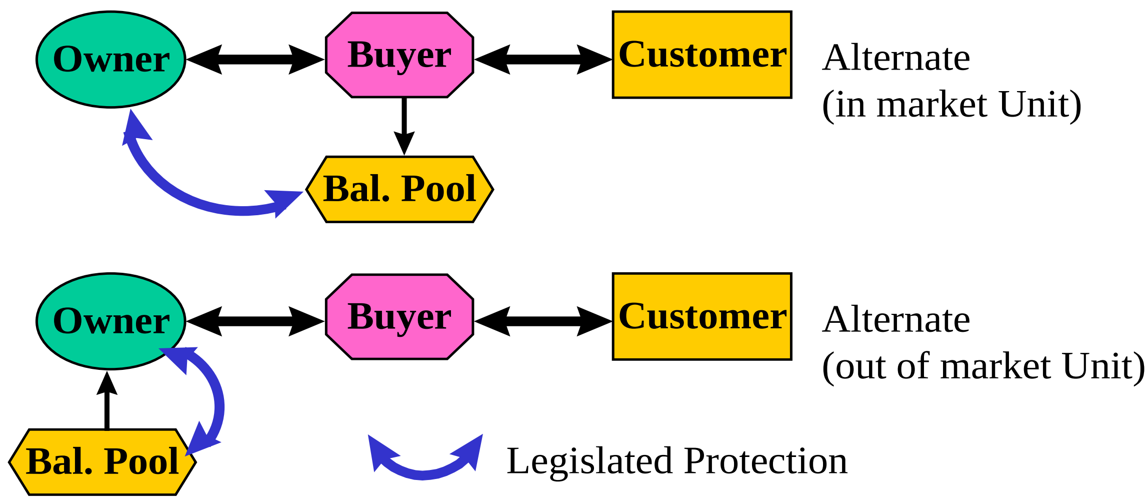
Balancing Pool (on behalf of customers)
(legislated, as opposed to contractual, obligations)

Major Obligations:
- ⇒ collect residual value payments from Buyer, make residual cost payments to owners of stranded plant (both as required)
- ⇒ maintain solvency of the BP (if BP is negative, acquire difference from customers) and transfer any residual value from PPA process to customers
- ⇒ reauction PPA if buyer defaults

Risks Held:
- ⇒ Buyer defaults and credit problems
- ⇒ Force Majeure for the events not insured by Generator, being strikes, lockouts or other labor disputes, civil disturbance, war,

epidemic, regulatory or governmental action, court restraints, etc.

Alternate Counterparty Arrangement



Alternative 4 - Risk managed by the Buyer

Letter of credit

The Buyer would be required to supply a letter of credit for the holding risk (equivalent of one year of fixed costs) plus three months of receivables risk. The letter of credit must always cover a period of no less than the current date and the following 12 months.

Parental guarantee

The Buyer would provide a parental guarantee for one year for the holding risk (equivalent of one year of fixed costs) plus three months of receivables risk. Parental guarantee always cover a period of no less than the current date and the following 12 months.

Pros: Risk lies with purchaser of the contract.

Cons: The cost of either the letter of credit or parental guarantee will be factored into the Buyers bid price for the PPA; and

To the extent that the BP must also backstop a portion of this amount, the contracting with the Owner becomes more complex: Owner - BP, Owner - Buyer.

EU Act Direction:

45.93*(3)* *On receipt of recommendations from the independent assessment team, the Minister may by regulation establish the rules relating to the holding of an auction and to the auctioning of power purchase arrangements in the intervals recommended under section 45.5(6).*

45.96*(1)* *The price paid for a power purchase arrangement under section 45.93 shall be paid, in accordance with the regulations,*

(a) *into the balancing pool if the amount is more than $0, or*

(b) *out of the balancing pool if the amount is less than $0.*

TransAlta preferred outcome:

TransAlta's preference would be Alternative 1 (TransAlta's proposed method) or Alternative 2, however any of the above could be made to work. Regardless of which of the above is chosen, we believe that some level of performance standard be provided by the Buyer.

Issue 6. Capacity Above Committed Capacity

Issue:

Any PPA must identify, in clear terms, what the Seller is selling and what the Buyer is buying. Each Party must be clear what is in and what is out of the terms of the agreement.

Any sale, by an Owner outside of the PPA, would be subject to compliance with pool rules and meeting market power requirements.

TransAlta Proposal

TransAlta proposes a single and fixed committed capacity level ("Committed Capacity") which is predefined in the PPA for each generating unit.

All unit capability up to the Committed Capacity should be covered under the terms of the agreement. A market based incentive formula would be employed to provide the Owner with the appropriate incentive (per Section 45.5(2)(a)(iii)). (See Issue 7. Incentive Pricing in the PPA)

Any capacity above the committed capacity would be to the sole and unfettered account of the Owner. Scheduling and dispatch protocols would cover the details as to how both the Buyer's and Owner's share of the Unit be scheduled (per Section 45.5(5)).

Underlying Concerns:

- TransAlta (as Owner) should not lose control of its sites, and the ability to control its assets. The PPAs must not become de facto expropriations.
- Societally efficient capacity expansion at a site will only occur if the decision maker (Owner) receives the correct economic signal and has the flexibility and control necessary to implement the change. Distorting the market's signal for development of existing sites will raise costs to customers, whether the distortion causes under-development at existing sites (forcing customers to buy from more expensive alternate

sites) or over-development (forcing a Buyer and customers to accept a PPA linked supply when cheaper sources of power exist).

- TransAlta entered into the deregulation and PPA process under the understanding that it would continue to have opportunities to optimize its sites.

EU Act Directions:

Section 45.4 (2)(b) [the Owner must submit] information relating to the fixed costs and variable costs of generating electricity at the expected available capacity of the generating unit over the effective term,

(3) The information provided under subsection (2) must,

(a) indicate how the fixed costs and variable costs, the expected available capacity and the amount of electricity expected to be generated may change over the effective term,

Section 45.5 (2) The independent assessment team shall,

(a) for each generating unit, determine a power purchase arrangement that is just and reasonable and that,

(iii) provides the owner with a reasonable opportunity to achieve efficiencies through incentives, including cost and output incentives, over the effective term,

(v) provides the owner with incentives for any future ongoing investment in the generating unit over the effective term,

(5) If the generating unit produces more electric energy than is anticipated in the power purchase arrangement that applies to it, the owner of the generating unit is entitled to the benefit associated with the exchange through the power pool of the excess electric energy produced, in accordance with the regulations, notwithstanding that the right to exchange the electric energy may be exercised by the purchaser of the power purchase arrangement pursuant to subsection (3).

Alternatives to TAU Proposal:

- The Buyer receives the right to all output from the generating unit, both from existing capability and from any capital additions which affect a generating unit.
- The Buyer receives the right to all output from the site.
- Each of the above suffers from:
  - Virtual "taking" of unit and site potential;
  - Owners loses incentive to expand unit on site and any output incentives for future investment;
  - The Buyer is not in a position to expand a unit at a site which it does not own;

– The Buyer may be forced to accept unlimited additional output and development at a PPA determined price which may be out-of-market;

– Distorted incentives and restrictions to economically expand the site will increase consumers costs as less economic options will be developed.

Dispatch and Scheduling Protocols:

- Owner's share is comprised of only that capability which is above the Committed Capacity;

- Owner has the right to bid its capability into the Power Pool. As a practical matter, the Owner may arrange with the Buyer that the Buyer bid such capability on the Owner's behalf;

- The Owner must demonstrate that the Buyer's Committed Capacity is available to the Buyer at all times while the Owner is producing energy to the Owner's account outside the PPA.

Identification of the ownership of the output from a Unit which can produce more than the Committed Capacity

- Example using a Unit with 100 MW of Committed Capacity, a minimum load of 30 MW, and 10 MW of additional capacity. Therefore, the unit can operate between 30 MW and 110 MW.

Buyer's Share	Owner's Share	Total Output	
1. Unit fully capable, Buyer and Owner successfully bid to full capability	100 MW	10 MW	110 MW
2. Buyer decides to not bid unit, unit scheduled off irrespective of desire of Owner (Owner's share is insufficient to meet minimum load level)	0 MW	0 MW	0 MW
3. Unit Capable of producing 100 MW (derated) and Buyer successfully bids in full capability	100 MW	0 MW	100 MW
4. Unit Capable of producing 100 MW (derated) and Buyer successfully bids in 50 MW (note: the 50 MW of undispatched capacity belongs to the Buyer)	50 MW (50 MW sp. res.)	0 MW	50 MW
5. Unit is fully capable and Buyer successfully bids in 50 MW (note: the 50 MW of undispatched capacity belongs to the Buyer)	50 MW (50 MW sp. res.)	10 MW	60 MW

Issue 7. Incentive Pricing in the PPA

Issue:

The EU Act, as amended, provides that the Owner with *a reasonable opportunity to achieve efficiencies through incentives*. Such incentives should be based on the value of the product that is being produced.

TransAlta Proposal:

The TAU proposal calls for the incentive to be based on the difference between the average monthly pool price and the variable price of production (in effect the energy's value). A differentiation between on-peak and off-peak is proposed to better define the value of energy in the two periods.

Any addition to this fundamental could be handled through bilateral arrangements between the Buyer and the Owner.

Underlying Concerns:

- TransAlta (an Owner) should be incented (bonus and penalty) in such a way that causes economic and efficient decisions to happen;
- Conditions will change over the 20 years of the PPAs. Any incentive mechanisms which are implemented should automatically react to the changes which will occur in the market;
- An averaging time period may be required to take care of market power issues and to retain the physical, as opposed to financial style of arrangement;
- Incentives which are not fully market sensitive will create costly and inefficient results;
- Corollary: All units should be similarly incented such that no perverse signals are entering the market;
- A high cost (stranded) unit should not be incented to build new stranded costs.

EU Act Directions:

Section 45.5 (2) The independent assessment team shall,

(a) for each generating unit, determine a power purchase arrangement that is just and reasonable and that,

(iii) provides the Owner with a reasonable opportunity to achieve efficiencies through incentives, including cost and output incentives, over the effective term.

Alternatives:

- [TransAlta's proposal] Incentive/penalty based on the market price (Power Pool spot price) for increased/decreased unit output capability as compared to the Expected Capability.
- Incentive based on a unit's cost, where increased/decreased capability is incented/penalized based on it's Fixed Costs or some derivative thereof.

Examples:

Case Assumptions				Owner Incentive		Buyer Impact	
	Fixed Cost $/MW.h	Variable Cost $/MW.h	Pool Price $/MW.h	Pool Price Based[1] $/MW.h	Fixed Cost Based[2] $/MW.h	Pool Price Based[3] $/MW.h	Fixed Cost Based[4] $/MW.h
1.	15	3	28	25	15	0	10
2.	40	3	28	25	40	0	(15)
3.	15	3	45	42	15	0	27
4.	40	3	45	42	40	0	2
5.	15	3	15	12	15	0	(3)
6.	40	3	15	12	40	0	(28)
7.	5	25	28	3	10	0	(2)
8.	15	25	28	3	10	0	(12)

- Above calculations
  1. Incentive = Pool Price - Variable Price
  2. Incentive = Fixed Cost
  3. Impact = 0 $/MW.h on average
     (actual pool price - average pool price for period)
  4. Impact = (Fixed Cost + Variable Cost) - Pool Price
- The above examples illustrate:
  - Any cost-based mechanism has an impact which may be adverse on the Buyer where price-based systems leave the Buyer relatively indifferent. In example 1 above, under a cost based incentive the Owner's incentive of $15/MWh may be insufficient to incur overtime and other expenses to speed up maintenance to return a unit from a forced outage. The Buyer would see a reduction in energy available and a reduced opportunity to sell the output at $25/MWh. Whereas if the Owner was incented at the pool price of $25, the Owner may be incented to incur the expense to speed up the maintenance and the opportunity would not be lost;
  - Different units receive different incentive signals in a cost-based mechanism, where each unit receives the same signal in a pool price-based mechanism. Comparing examples 1 and 2 above under the cost based scheme, the Owner in

example 1 would optimize maintenance given a $15/MWh signal, employ little overtime and incur a longer maintenance outage. The Buyer could suffer a lost opportunity due to the unavailability of energy. The Owner in example 2 may incur significant expense, given a $40/MWh signal. The Buyer in example 2 is obligated to pay for the extra energy that the Owner is incented to produce at $40/MWh, even though the Buyer incurs a loss by selling the energy to the pool at only $25/MWh;

- Owners could be incented to build new stranded costs in the cost-based mechanism, where this would not happen with the price-based mechanism.