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Finally, a Plan (albeit drip-by-drip) to Phase Out Coal *and* Keep the Lights On

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Documents and Press Releases Commented On:
(1) Press Release, Electricity Price Protection, November 22, 2016;
(2) AESO, Alberta's Wholesale Electricity Market Transmission Recommendation, dated October 3, 2016, released November 23, 2106, accepted by the Province;
(3) Press Release: Alberta Announces Coal Transition Action, November 24, 2016 and related letter from Terry Boston to the Premier of Alberta (dated September 30, 2016, released November 24, 2016).

The week of November 21, 2016 will go down as a significant week in the evolution of Alberta's electricity market. Having introduced Bill 27, the *Renewable Electricity Act* on November 3, 2016 (see post here) the provincial government followed that up this last week with a number of significant initiatives.

First there was the announcement on Tuesday November 22 that the province was going to cap electricity prices in the retail market. *Second*, on Wednesday November 23, the province announced that it planned to accept the recommendations of the Alberta Electric System Operator (AESO) to introduce a capacity market in Alberta to supplement the existing energy only market and then, *third*, on Thursday November 24 there was the announcement that the province had reached a settlement with the owners of the six coal generating facilities with useful lives beyond 2030 who will be required to cease burning coal at those facilities by then. And later that same day, the province announced tentative settlements with most of the parties affected by the province's efforts to question the ability of the buyers under power purchase arrangements (PPAs) to turn responsibility for those arrangements over to the Balancing Pool. "Black" Friday was almost quiet, except for the morning's announcement that, as of January 1, 2017, the province would "prohibit unsolicited door-to-door selling of energy products to protect people from misleading high-pressure sales tactics."

This is a very positive package of measures. It offers comfort to consumers that they will be protected at least in the short term from excessive price volatility on the upside. It offers a realistic strategy for obtaining the investment that the province needs to build combined cycle gas generation to replace the coal fleet and thus addresses potentially very serious energy security concerns. It offers comfort to coal generators that they are being treated fairly in relation to stranded assets and gives them both the wherewithal and reason to invest in the construction of new generation. And finally it splits the difference between the province and the PPA buyers in their dispute on the terms of the PPAs. This was an important package to put together. Without it the transition from coal would be more risky (in energy security terms) and likely more expensive (increased cost of capital). While a significant change in market structure such as this is not without its own risks (a perception of continuing change will deter investors) most agreed that an energy only market was not going to deliver on the energy security front.

While just about everybody is a winner in this brave new world there will be some losers; topping that list will likely be electricity retailers but also incumbent renewable generators; and there may still be a spoiler. As of the time of writing, Enmax had not joined its fellow PPA buyers in settling with the province in the province's bid to strike out the "more unprofitable" language from the PPAs. Finally, in most cases, the details of the above initiatives have yet to be worked out. But now at least we have something that look like a plan. It might have been dribbled out over the course of a few days, if not weeks, but this looks like a coherent plan for getting off coal and keeping the lights on. This is a significant achievement.

Capping Electricity Prices

The cap on electricity prices for consumers will be implemented using the Regulated Rate Option (RRO). While Alberta has competition at both the wholesale level (implemented through the power pool operated by AESO) and the retail level (through competition between retailers), Albertans do not have to participate in the retail market by signing a contract with a retailer. Instead, the default is the so-called regulated rate option which must be offered by the distributor or its designate (see Regulated Rate Option Regulation, Alta Reg 262/2005). The RRO is only available to certain customers including residential, farm and irrigation customers. The RRO has been much criticized as inconsistent with the ethos of market based approaches to pricing electricity (see Power for the People Report) but even a string of conservative governments committed to market pricing proved to be unwilling to take the political risk of forcing consumers to make their own contracts for electricity and natural gas. Apparently we can choose our contract providers for pretty much anything else but not electricity or natural gas (and here I confess that my household is on the RRO – inertia being the principal reason!).

The main consequence of using the RRO as the vehicle for delivering the price cap is that RRO customers are the only parties that will benefit from the price cap. The price cap will not affect generators. Generators will continue to receive the pool price. Neither will the cap affect the RRO provider. The government is committed to keeping the RRO provider whole. The parties that will most likely be adversely affected are the retailers offering a competitive service. Their offerings will not be subject to a cap. Hence, if customers perceive a risk that contract prices will exceed the RRO cap then we can expect these customers to migrate *en masse* back to the RRO. While the risk of this should be present in the minds of customers holding contracts over the longer term, in the shorter term there is little risk of getting anywhere close to the cap with the present oversupply forecast to continue for a number of years and current prices far below the 6.8 cents\kwh of the cap. But still there must be a chilling effect on switching away from the RRO and it is hard to imagine new retailers entering the competitive market in these circumstances.

Compensating the Coal Fired Generators

Three companies, TransAlta, Capital Power and ATCO Power, will each receive compensation based on the operating lives of assets which had predicted end-of-life dates between 2036 and 2061. The payments have an overall value of $1.1 billion (2016) and will be made over a period of up to 14 years.

Facility	Owner	End-of-life
Keephills 3	Capital Power & TransAlta	2061
Genesee 1	Capital Power	2044
Genesee 2	Capital Power	2039
Genesee 3	Capital Power & TransAlta	2055
Sheerness 1	Atco Power and TransAlta	2040
Sheerness 2	Atco Power and TransAlta	2036

The compensation formula was developed by Terry Boston who was retained by the province. Boston's letter to the premier suggests that "The criteria are based on net book value of the assets – which is fully auditable and transparent – pro-rated by the years stranded by the policy decision to account for depreciation, and discounted for the probability some of the components of the assets can be re-used." Boston suggested aiming to have about half of the existing coal facilities changed over to gas rather than constructing all new combined cycle gas plants. This will be both cheaper and produce a generation fleet with more diverse vintages.

The PPA settlement

I have described the PPA dispute in two previous posts here and here. The judicial review application launched by the province has the two-fold objective of striking the "more unprofitable" language from the change of law provisions of the PPAs and quashing the decision of the Balancing Pool to accept an assignment of one of the PPAs. The overall goal of the province in launching the application was to protect consumers from being saddled with the economic burden of the unprofitable PPAs.

The province appears to have reached settlements on this litigation with Capital Power, TransCanada and AltaGas. Thus far there has been no similar announcement with respect to Enmax. Enmax is a wholly owned subsidiary of the City of Calgary and Mayor Nenshi has been unrestrained in his criticism of the province for having the temerity to question this unorthodox backdoor "amendment" of the PPAs.

Although, so far as I am aware, no details of the settlement have been released, the reports in the press suggest that the conceptual underpinning of the settlement is that the Province will cover the incremental costs associated with the carbon levy while the PPA buyers continue to bear the market risks. That makes sense since it would be consistent with the basic understanding in the PPAs which was that the buyers were picking up the market risk but should be shielded from the risk of changes in law. The arguably unlawful addition of the "more unprofitable" destroyed that basic bargain by allowing the buyers to transfer market risk back to government, carried on the back of a change of law.

That conceptual underpinning would be easier to see if the buyers were to keep the PPAs and if monetary compensation were to flow from government to the buyers. But that is not what is happening. It seems that the buyers will get to "terminate" (i.e. assign the balance of the term of the PPAs to the Balancing Pool) but in return must pay the estimated (perhaps guess-timated) discounted market losses to the BP, since upon taking the assignment it is the BP that will bear the market risk. (See Capital Power Press Release, November 24, 2016, stating that Capital Power and its syndicate partners have agreed to pay the Balancing Pool $39 million). There are probably a number of good reasons for structuring the saw-off this way. One reason, as the events of this week amply demonstrate, is that we are going to see more changes in law coming down the pike. And it would be unfortunate indeed if we were to keep- re-playing this record over the next few years. Having the BP hold the PPAs avoids that scenario.

I think that this is a reasonable saw-off because I think it respects the basic bargain. The amendment to the change of law clause was at the very least improper if not simply unlawful. It was clearly not a house-keeping measure, since, as noted above, it changed the basic structure of the bargain by allowing the buyers to transfer market risk to the government\consumers under cover of a change of law. With this addition, the clause was no longer a "normal" change of law clause. And for that reason the amendment was also procedurally flawed since the significant change never went through the public review that was contemplated for the terms of the PPA. But this was hardly the time for the government to put this all this at issue. The province would likely have faced limitations problems in making its case, but of more practical significance, the litigation was sending all the wrong messages at a time when the province needed to be able to attract significant capital investment in the power sector. Whether Enmax will come to the table or whether the matter will still proceed through the courts remains to be seen.

One final thing. There has been some talk about the Notley government acting like a "banana republic" (Adam Legge, Calgary Chamber of Commerce, see Calgary Herald Article here) in the way that it has approached these issues, even threatening to undo the amendment by targeted retroactive legislation. Apart from the odious nature of Mr. Legge's terminology (Mayor Nenshi to his credit has chosen his words more carefully he simply refers to the government as "absolutely nuts"), these accusations miss the mark. If anything the litigation was attempting to uphold the rule of law in the face of what looks like backroom cronyism of the worst kind. And as for the retrospective legislation I think that all that it would have done was to restore the basic balance to the change of law clause as discussed above. And it would not have been unprecedented. Newfoundland has tried for years, indeed decades, to restore the basic balance to the deal struck for the development of Churchill Falls and has been thwarted only by the technical argument that the contract in question in that case was found to be "located" outside the province and therefore beyond the reach of the legislative assembly of Newfoundland and Labrador: *Reference re Upper Churchill Water Rights Reversion Act*, [1984] 1 SCR 297 (CanLII). Unfortunately for Enmax it is crystal clear that these PPAs are located right here in Alberta.

The Capacity Market

The AESO report to government confirms what many had been saying over the last year which is that Alberta's energy only market (EOM) will not be able to deliver energy security; perhaps not under any circumstances but certainly not without creating tremendous price volatility which customers, and therefore ultimately politicians, would not tolerate (with or without a consumer retail price cap). While some argue that new developments in energy storage will help firm up the capacity of renewable sources at this stage that seems quite speculative. There is no doubt some political advantage for the opposition parties to argue that it is the NDP government that has broken the energy only market, the reality is that such a market will probably only work for so long as there is steadily rising demand (load). Such a market probably cannot deliver energy security (lights on) in the face of multiple uncertainties including low oil prices (and therefore lower growth in load), changing government carbon policies and general economic uncertainty.

But if we conclude that EOM is broken there is still the question of what to do about that. The AESO Report considered four options: (1) stay the course (i.e. retain the commitment to the EOM), (2) introduce a capacity market, (3) long term contracting, or (4) a return to cost of service regulation. The AESO report comes down heavily in favour of introducing a capacity market having evaluated the options against a number of criteria: reliable and resilient system, environmental performance, reasonable cost to consumers, economic development including job creation, and orderly transition (costs and risks). The report offers a nice summary of the need to provide two streams of earning to generators (energy and capacity earnings) as follows (at 40):

> As more and more renewables are added to the supply mix, Alberta is moving into an environment where it will be energy rich but capacity limited, due to the non-dispatchable nature of a significant portion of the generators in its electricity system. With additional intermittent renewable resources the electricity system will have sufficient or even excess energy at times; however, due to the intermittent, low-reliability capacity value of the resource, supply adequacy cannot be guaranteed. The price signal provided by the current energy-only market increasingly will not signal for new investment. In order to ensure that new generation capacity is developed in a timely and orderly manner, Alberta needs to put a specific value on the attribute of "capacity." A capacity market will accomplish this. A capacity market will ensure reliability by maintaining supply at a targeted level, something which the current energy-only market structure does not do.

From a legal perspective perhaps the most interesting part of the report is the analysis of the costs and risks of an orderly transition for the four options. With respect to the introduction of a capacity market the AESO acknowledged that the design and implementation process would be time consuming and likely take about three years with some risk (given current rule making processes (including appeals) (see *Electric Utilities Act*, SA 2003, c E-5.1 ss.20 - 26)) that it might not be achieved in a timely manner and thus might require "a more prescriptive approach (AESO Report at 33) – which I take to be code for legislation. The report went on to note (at 33):

> The role of regulatory oversight in the capacity market will need to be established, with a particular focus on clarifying roles, responsibilities and methods to ensure the reasonableness of capacity costs and determine their allocation. This may require minor legislative changes but should not impact the overall role and mandate of existing electricity agencies. In addition, other design decisions must be made early in the design process. Changes to transmission, hydro or intertie policy, as well as treatment of coal generation and renewables, can be incorporated into a capacity market. Design of the capacity market would proceed more efficiently if these policy directions were established upfront, while changes introduced later may result in delays to capacity market implementation.
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> Unlike the non-market structures [cost of service regulation and long term contracts] there should be fewer claims for compensation with this structure change.
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> During the transition period while a capacity market is being implemented, it is highly likely that a "bridging mechanism" will be required to ensure reliability before new supply supported by a capacity payment is added to the system (the period from 2021-2024). No investments in new supply are expected until the details of the capacity market are determined. Bridging mechanisms may range from contracts with specific loads to curtail during supply shortages to interim (five year) capacity-like contracts with new generation supply. These contracts

> would be entered into with the understanding that the new supply will eventually need to compete in the capacity market. In addition to the cost of entering such arrangements, there is some risk that market participants will push to have these contracts extended and continued, thus defaulting to an unintended, alternative market structure [long term contracts].

The bridging would be required because the new scheme will likely take three years to fully implement meaning that the first capacity auctions would be held no sooner than 2019 or 2020 while the time required to build new gas generation is five to seven years.

Also of interest is AESO's assessment of how the capacity market will fit with other elements of the province's climate leadership plan. Here the AESO assured government that its renewables program will not be compromised although to the extent that generation has two streams of earning, one would expect energy prices to be lower. This will mean that payments under the contracts for difference approach that the province has adopted will be larger. It may also mean that (at 38) "A portion of the renewable support may be transitioned into a capacity market by carving out volumes for renewables with capacity value." Furthermore there should be a good fit with coal generation phase-out since (at 38) "a competitive auction for capacity [held] in concert with a retirement schedule provides transparency, mitigates supply adequacy concerns, and can be used to smoothly reduce the volume of coal that can depart from service in any given period." There might also be a good fit with energy efficiency policies (at 39) to the extent demand curtailments could be brought in to a capacity market. Presumably as well the capacity market approach offers some flexibility to accommodate future technological developments in relation to storage and distributed generation.

Those who will be negatively impacted by the change in approach may include incumbent renewable generation and perhaps incumbent co-generation facilities. Incumbent renewable will be negatively impacted since the introduction of a stream of capacity payments should serve to depress prices in the energy market. Since most renewables will not be able to earn capacity credits because most are non-dispatchable unless matched with storage (hydro and biomass-fueled generation will be the key exceptions) their overall revenue stream will decline. Some co-generation "may actually prefer the revenue upside offered by a more volatile and higher energy price" for their surplus generation.

For those who were thinking of a return to the good old days of cost of service regulation the AESO report carried the warning that this would be like putting Humpty back together again (vertically integrated utilities); a Herculean task creating all sorts of winners and losers with claims for compensation by the losers, a process (at 34) that "would involve legal challenges and take significant time."

Market Design Issues

The capacity market will operate alongside the energy market. The AESO recognizes that the details of market design matter a lot. These details will have to be worked out (negotiated) with the industry over the next few years. Appendix D to the report discusses some key design considerations for a capacity market including: (1) The method for determining the volume of capacity required. (Elsewhere the report suggests (at 39) that the amount of capacity to be purchased to give an appropriate security margin would be 15% higher than expected peak load.) (2) The question of who holds the obligation to procure capacity? The ISO or load serving entities? (3) The contract term, delivery period and frequency of procurements? Here the report notes that (Appendix D at 1):

> Typically, capacity contracts are between one and five years in duration but other durations are possible. New resources often receive longer contract terms than existing resources. In addition to contract duration, it must be determined how far ahead of time before the contract start date the contract should be procured. Typically, procurement is done one to four years ahead of the contract start date but other options are possible. The potential and timing of subsequent procurements after the initial procurement for rebalancing of volume procured must also be established. How often a procurement process is held and how many procurements are conducted for a delivery period must be established.

(4) Resource eligibility. Here the relevant considerations include:

- Whether existing or only new resources will be eligible;
- The "firmness" of the resource, or degree of certainty that the resource would be able to provide energy if required, and the proportion of the resource which would be eligible to provide capacity; and
- Treatment and requirements for resources such as energy efficiency, price responsive load, cogeneration, intermittent renewable resources and interties.

(5) Delivery requirements and performance assessment and incentives. (6) Market mechanics (e.g. price caps and floors, market power mitigation, and secondary markets). (7) Allocation of capacity costs amongst load.

In sum it is evident that much remains to be done and there will be a very active debate as to manner of these variable. And somebody will have to act as the umpire. Will that be the AESO itself or the Alberta Utilities Commission?

Other Matters

Terry Boston's four page letter to the premier is well worth reading for its strategic advice to the province. Three of his recommendation stood out for me. I have already referred to his comments on coal-to-gas conversions for some existing coal plants. Boston also noted that this might require some relaxation in proposed federal carbon standards for gas generation. Second, he suggested that there should be more exploration of demand side management measures to manage peak demands rather than building simple cycle peaking plants. And finally, Boston makes a big pitch for hydro not only because of its capacity and flexibility benefits but also because of its benefits to Alberta's economy insofar as "Around 80 per cent of capital dollars for new hydroelectric development will be spent in Alberta as opposed to construction of other renewable resources (which use mostly imported equipment, resulting in less than 20 per cent of the investments for wind and solar being spent in Alberta's economy)." This will no doubt ignite an active debate about the pros and cons of significant hydro developments in Alberta a debate that will need to involve First Nations and Metis communities as well as environmental interests.

A final comment on process. The public record suggests that the AESO took the initiative in deciding to study how an energy only market might perform under changing condition and what the alternatives might be. It did so in a very non-public way. The process from here on in will be public, but the decisions to start the process, to consider options, to recommend to government and ultimately the government's decision to adopt a capacity market approach were all made behind closed doors. The consultants retained by AESO spoke to a select number of market participants about the issues but there was no broad, open and transparent consultation. I find that surprising from this government. As I have said before I have been hoping that this government might do thing differently, that it might proceed by publicly considering and assessing options and developing white papers and the like before settling on a particular approach. But on matters involving electricity that seems not to be the case. Why is that? It may the need to act quickly and resolutely, but the Leech report process suggests that it might be possible to achieve those goal and engage in a more public consideration of alternatives

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