Let's Keep Electricity Markets Working for Albertans

By Cliff Hamal and Chris Ring

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I. Executive summary

The challenges facing the Alberta electricity market are clear. The goal is to transform the sector, with substantial increases in renewable generation and phasing down coal generation. The means by which this will be accomplished, however, is still a work in progress. The Government of Alberta (GoA) recently announced support for the plan put forth by the Alberta Electric System Operator (AESO) for a wave of renewable generation procurement. While this step is consistent with the overall goal of industry transformation, the broader implications need to be considered and a path charted that includes not only short-term actions, but the longer-term structure of the industry. Actions have consequences, and these steps will set in motion changes that will be felt throughout the Alberta electricity industry.

Reliable electric energy is the lifeblood of a modern economy, with benefits to everyone when delivered at the lowest cost. There are other considerations, of course, and room for both differences in opinion and assessment of risks. Environmental consequences have always been a consideration. Increasingly, the desire to shift to carbon-free and renewable resources is guiding new investment and leading to the early retirement of existing generation in many markets in the developed world. This is leading to other issues having to do with reliability and operations. The ongoing debate over these issues is a healthy one, with reasonable viewpoints reflecting differences in values and perceptions of risk. Rather than debating these goals, we turn, instead, to consideration of industry market design. There are choices that can be made today to lower costs and increase flexibility, which will be helpful regardless of the choices made over time regarding Alberta's energy supply mix.

As policymakers consider the evolution of the Alberta electricity market, there is no doubt that the policy of supporting market processes that are fair, efficient and openly competitive (FEOC) will continue. Healthy competition can provide real benefits in terms of costs, innovation and market responsiveness. What constitutes healthy competition, however, may not be obvious. Or worse, what looks most like competition may actually create incentives and market dynamics that prevent the best outcomes at the lowest costs.

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The problems lie in the details, but their consequences are far from small. The seemingly purest markets involve centralized procurement of short-term products for energy and ancillary services, which has also included capacity in some markets. Alberta has pursued this approach with success in adopting a particularly streamlined energy market (without capacity) and no locational price differences. The power of competitive auctions is that they provide a ready means of procuring standardized products for the lowest offered prices. The problems, however, rest in the need for standardized products and timeframes inconsistent

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with system optimization and investment decisions. And in particular, now that Alberta is differentiating electricity supplies based on fuels and environmental consequences, the simple centralized approach faces challenges. Markets in the U.S. and elsewhere that have tried centralized auction approaches when there really are differentiated products have faced a constant stream of market problems and continual rule changes. All of these changes point to outcomes that are inconsistent with efficient, low-cost solutions.

Markets everywhere are facing these challenges. Despite roughly twenty years of experience in competitive electricity markets, there is no consensus on all aspects of the market. Some elements are clear. Short-term energy prices, based on a single market clearing function[1] optimize the production of electricity, focus competition effectively, and deliver energy at the lowest cost. The problems arise when considering incentives for investment and other steps needed for reliability. These other actions were relatively easy to deal with under the regulated, vertically integrated utility structure, and some even call for a return to that approach. In most cases, however, there are ongoing modifications to the energy market structure, where market perfection always seems just one more step away.

A very different alternative is one where procurement has the flexibility necessary to target resources with operating and economic characteristics that meet the system needs, when and where they are needed. The procuring agent works on behalf of customers under the goal of long-term optimization, and contracts for resources over a long time period to obtain the resources at the lowest cost. While there are many advantages to having the flexibility to target the specific needs of the market, the most obvious and demonstrable advantage is the lower cost of financing available through long-term commitments. The purchaser would still get the benefit of lower prices that reflect competitive processes, and thus meet the FEOC requirements. Possible purchasers on behalf of customers include a government authority or the private companies that distribute electricity to customers. And while either structure could be used to purchase power, there are competitive advantages in having procurement through multiple purchasers, as opposed to a single agency.

Under this approach, hourly energy markets remain competitive, with system optimization and market clearing conducted by the AESO, as it is today. And competition is embraced to drive down overall costs. A combination of short-term markets for dispatch optimization, and long-term procurement for resource development, provides the best means for efficiently meeting operating challenges and environmental goals.

There is also the temptation to think there is a sustainable middle ground, with long-term procurement used in some situations, while energy-only prices are used to procure generation in others. And it appears that Alberta might be headed in this direction, with renewables procured with long-term price guarantees, and the energy market alone relied upon for providing price signals for other supplies. This approach, unfortunately, has the potential for the greatest costs and lowest reliability. There is an inherent conflict between relying on short-term prices to attract new supplies in some respects, but then have directed GoA intervention and long-term contracts in others.

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The evaluation of these approaches requires a deep dive into the details of operations and performance. Some will argue that an approach involving longer-term strategic decisions by anything but unregulated investors responding to short-term market signals will inevitably end up raising costs. Such criticisms rest on a faulty premise, however, that there is a purely competitive alternative. For electricity, this simply is not true. Electricity has never been, and never will be, a purely competitive market, where willing buyers and

[1] Alberta adopts a single market clearing price, which is possible due to minimal internal transmission constraints, but virtually every other market uses locational prices.

sellers come together for transactions unfettered by outside rules and requirements. This is because electricity is delivered from an overall system, where actions of all buyers and sellers influence each other and reliability is either maintained for the entire system—or it collapses. The AESO ensures the system is kept in balance at all times without overloading transmission lines. And this means that no market option relies purely and simply on competitive behavior.

In evaluating such choices, economists refer to the informal Law of Second Best to raise important cautions. In judging imperfectly competitive markets, the best option does not lie in which alternative has the most trappings of a competitive market. It is not the case that the market that looks most superficially competitive will deliver the best results. Instead, the best option needs to be assessed on a clear standard. Here, it should be the option that can be expected to deliver the desired service, with the necessary level of reliability, most efficiently over the long term. The proof is in the actual performance.

Alberta faces many challenges in moving forward in its electricity market. Environmental goals, system performance (including reliability) and cost minimization are all important priorities. In addition, existing obligations for investments, workers and transitional commitments need to be maintained. Over time, it is inevitable that other goals will be established and perceived needs will change. The market approach involving long-term procurement and short-term optimization, as detailed below, can accommodate these other obligations and changing needs.

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II. The Alberta electricity industry is facing new and different challenges

Alberta has committed to a dramatic change in its electricity supply portfolio, with the retirement of the majority of its coal fired generation and a dramatic shift to renewables. This promises cleaner air and reduced greenhouse gases. It will also involve increased expenses. While this part of the transformation is clear, there are added layers of change needed that may be equally significant within the operation of the industry and its markets. Targeted changes to encourage renewables will not be enough. More fundamental changes to the nature of the electricity industry are coming, whether policymakers are ready to grapple with them or not.

a. The shift toward renewables

The most publicized indicator of the shifting future of Alberta's electricity industry was the Alberta Climate Leadership Panel's November 2015 report and Premier Notley's related speech, which elevated Alberta's environmental stewardship goals.[2] The new goals seek to end the use of coal-fired power by 2030, while replacing at least 50-75% of it with renewable power, and increasing renewables' overall share of Alberta electricity to 30%.[3] Alberta has a long way to go in order to meet these goals—in 2015, coal accounted for about 40% of the province's capacity to generate electricity, while renewables accounted for about 17%.[4] And while most of Alberta's coal plants are expected to shut down before 2030 anyway, six are not. The early retirement and construction of renewable generation is expected to cost several billion dollars.[5]

Alberta put steps in motion to implement these changes, first by directing the AESO to create

[2] Government of Alberta, Climate Leadership: Report to Minister, November 20, 2015; Government of Alberta, Climate Leadership Plan speech, November 22, 2015.
[3] Government of Alberta, Climate Leadership: Report to Minister, November 20, 2015 at 6.
[4] Alberta Utilities Commission, http://www.auc.ab.ca/market-oversight/Annual-Electricity-Data-Collection/Documents/2016/CapGen_Interchange2015.pdf.
[5] Youri Chassin and Mark Milke, "Green Energy Subsidies: Is Alberta Jumping on the Bandwagon?" Montreal Economic Institute, March 2016. *See* also Duane Carlson and Allen Crowley, "EDC's Impact Assessment of Climate Leadership Plan," EDC Associates Ltd., prepared for IPPSA, January 25, 2016, slide 37.

a plan for developing renewable generation,[6] and then by approving[7] the plan that AESO proposed.[8] Under the plan, new development will be done through an auction procurement program administered by the AESO. The process will have three stages, involving expressions of interest, assessments of qualifications and then complete offers where the winners will be decided on scored basis with heavy emphasis on price. A term sheet recently released by the AESO proposes variable support payments that will increase revenues from the volatile hourly market to ensure the generator ultimately receives the contract price.[9] The terms proposed by the AESO still await stakeholder comments, and even after they are finalized, they may change over time. From our perspective, the basic principles are clear. The AESO will act as a central buyer, committing long-term to pay a premium over the energy market prices to ensure the development of renewable resources. The money to make these renewable payments ultimately comes from either customers or taxpayers, which in a general sense, are the same entities. The revenues from a carbon tax will likely play a major role in funding these resources, but inevitably, those are taxpayer funds that could otherwise be used to displace other taxes.

Alberta's current electricity market structure is not configured to meet the Premier's environmental goals. Markets like Alberta's deregulated energy market create strong incentives, but only based on factors that are priced. Prior to the new renewable program, Alberta has not offered sufficient incentives or subsidies for higher-cost renewable energy needed to reach Alberta's environmental goals. And the increased costs will total in the billions of dollars.[10] The subsidies needed to incentivize renewable generating capacity construction have been studied, but it is unclear whether carbon tax revenues generated from the electricity industry would be sufficient to pay for the needed subsidies. Nevertheless, the carbon tax program will provide billions of dollars that can be used to support, at least in part, renewable energy, with a tax of $30/tonne on carbon emissions in 2018.[11] Clearly, changes to the market structure are needed in order to meet Alberta's environmental goals.

The renewable generation procurement program under development by the AESO will be a critical part of the future Alberta electricity market. Simply making funds available to support the desired renewables, however, is not enough. The funding must work within the broader framework of the electricity market so that all of the objectives, such as reliability and overall cost efficiency, will be achieved.

b. Additional challenges on the horizon for Alberta's energy-only market

There are several challenges that result directly from the shift toward renewables. Foremost will be the need to take actions to ensure reliability. While the new generation will have environmental benefits, coal generators typically have outstanding operational characteristics. Those generators tend to be supremely reliable and can operate over a wide range of output levels, as well as being readily responsive to dispatch signals calling for different output levels.

Wind and solar resources, however, are dependent on the vagaries of nature. This creates dispatchability issues for operating the system—turning the right resources on at the right times to

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[6] Sprague, Grant D., Q.C., Deputy Minister Energy, letter to David Erickson, AESO, January 25, 2016. *See* also "Renewable Electricity Program Recommendations," AESO, May 2016. https://www.aeso.ca/assets/Uploads/AESO-RenewableElectricityProgramRecommendations-Report.pdf, at 1.
[7] Alberta Ministry of Energy press release, November 3, 2016, http://www.alberta.ca/release.cfm?xID=43752ABFE959B-9AD9-9E3C-DBFCF5B5CA13C24C.
[8] "Renewable Electricity Program Recommendations," AESO, May 2016, https://www.aeso.ca/assets/Uploads/AESO-RenewableElectricityProgramRecommendations-Report.pdf.
[9] AESO, "Key Provisions of the Renewable Electricity Support Agreement," November 10, 2016, https://www.aeso.ca/assets/Uploads/REP-RESA-Term-Sheet-for-Stakeholder-Comments-10-11-2016.pdf.
[10] Kim Trynacity, "Accelerated coal phase-out could cost Alberta $8 billion, new study concludes," CBC, October 29, 2016, http://www.cbc.ca/news/canada/edmonton/accelerated-coal-phase-out-could-cost-alberta-8-billion-new-study-concludes-1.3826318.
[11] Alberta Government, "Ending coal pollution," http://www.alberta.ca/climate-coal-electricity.aspx.

generate all the electricity that is needed becomes more of a challenge. If the system must balance these supply-side issues with demand-side responses like energy users being paid not to operate, things get even more complicated.

Replacing coal with non-dispatchable renewables, therefore, raises reliability problems. More than ever before, Alberta will need to ensure that it has the capability to deal with rapid changes in residual demand—the resources needed to meet load after deducting the non-dispatchable generation from resources like wind and solar. As the share of these resources increases, the problems become more pronounced. Wind generation often runs strongest at night, driving down prices and forcing thermal generators to turn off due to low prices which would otherwise leave the system short during peaks of the following day. California is dealing with problems caused by large quantities of solar power which all fall off at the end of the day, precisely when load may be peaking. And backup supply may not be needed often, except on those high peak load days that happen to be cloudy and windless. The current market design is not well-suited for these needs.

There are also general timing issues associated with the construction and retirement of generation resources which can be particularly complicated when a system is undergoing dramatic change. Reliability of the system depends on always having sufficient capacity. Customers and system operators tend to prefer a situation where uncertainties are addressed through resource overlap, so no shortages occur. Investors, on the other hand, are naturally reluctant to building when needs are not certain, and are troubled by the low prices associated with excess capacity in such overlap periods. The occasional shortage may even be a good thing for suppliers. The system is fine when everything is in perfect balance, but perfection is impossible.

There are also general trends in the industry having to do with increased participation by load in wholesale markets where it contributes to maintain system balance through curtailment (i.e., demand side management). This can be very helpful in managing some of the issues addressed above, but the pricing mechanisms require special considerations. Also, there is a growing trend toward distributed generation in the industry which produces different concerns having to do with dispatchability, price signals, and sales of excess energy back to the system.

Finally, a well-functioning electricity industry should serve much broader societal goals. Reliable, low-cost electric power is not only a key indicator of a modern society, but it is integral to a tremendous portion of economic activity and even personal enjoyment. Policymakers properly consider its wider implications. There can be industrial policy goals that are supported by actions or pricing in the electricity supply industry. Retail rates reflect consideration of income disparities and social welfare. Environmental goals can affect electricity industry operations. The workers who have diligently kept Alberta's coal plants running reliably for years cannot be left behind. Retraining and other expenses must be factored into Alberta's energy equation, and under the current deregulated environment, they are not. First Nation rights must be respected, with appropriate time for consultation and, where appropriate, funds for compensation and participation. Considerations like these are very difficult to incorporate into a market structure. Failure to incorporate such considerations is one reason that markets have failed elsewhere, but with Alberta's electricity market facing a need for fundamental adjustment, these considerations should be addressed head-on.

c. Questioning the continued success of Alberta's energy-only market

Alberta has operated on the energy-only market design since its inception and has been successful in attracting new investment thus far. Supply has been adequate, with ongoing investments and stable reserves. On a forward basis, the AESO does not anticipate any shortfalls over the next two years.[12] Despite this success, we conclude that there are changes which will present clear challenges ahead and problems if changes are not made. This conclusion rests in part on what can be learned from the performance of other markets. The energy component of electricity prices has been insufficient

[12] "Long Term Adequacy Metrics," November 2016, AESO, p. 15. https://www.aeso.ca/download/listedfiles/2016-11-LTA-Final.pdf.

in most other locations and additional means have been adopted to provide sufficient revenues, such as capacity markets or formal scarcity pricing rules. The one debatable standout is the Texas ERCOT market, which relies heavily on energy market prices. It has had substantial investments, it is true, but also claims by investors that market information was misleading and there are concerns over its long-term viability as currently configured.

Ongoing market design revisions in Ontario, UK, PJM, MISO, New York, California and New England indicate problems with energy-only markets. Alberta's continued success or impending problems will depend on the unique circumstances of its market. In that respect, there are four critical concerns.

Ongoing market design revisions in Ontario, UK, PJM, MISO, New York, California and New England indicate problems with energy-only markets.

First, some of Alberta's success in having energy market prices sufficiently high to attract new investment depends on the dynamic performance of the hourly energy market. In many markets, there is substantial pressure and oversight to drive competitive market prices down to the short run marginal cost of the marginal generating station in each hour. This is less true in Alberta. The market started with supply largely concentrated among three suppliers.[13] This oligopoly structure provided the opportunity for profitable bidding above short run marginal costs at critical times. Within a boundary of reasonableness, this was not considered a problem by the Market Surveillance Administrator (MSA), and higher prices have attracted investments.[14] As recently as the third quarter of 2014, the MSA noted that the average pool price of $122.54/MWh in July was driven, in part, by economic withholding by generators.[15] During this past July, however, the average price was only $18.21/MWH and the MSA concluded there was no economic withholding.[16] The industry is not as concentrated as it had been,[17] reducing the opportunity for strategic bidding, and the fall in gas prices has also put downward pressure on prices. At current levels it is reasonable to expect inadequate prices for investment when needed. But, it gets worse.

Second, with the expected retirement of coal generators and addition of new supply (renewable and gas), the concentration of generation assets should be expected to diminish even further. Incentives for economic withholding in an oligopolistic market structure is a fickle thing. And when firms conclude it is no longer worthwhile (or otherwise decide to change strategies) there can be a swift step-change in market prices.

Third, the expansion of near-zero marginal cost renewable resources creates the potential for falling energy prices. This issue can rise to the level where resources on the margin are producing energy at prices of zero or lower. This has been an issue in every market where the share of renewable resources has grown, including Texas: overall costs of delivering energy increase while the hourly energy price (based on the marginal cost of the marginal resource) has fallen. This has been a particularly challenging problem in Ontario, where market design includes a means of recovering these other costs through what is called the Global Adjustment. With Ontario's strong commitment to eliminate coal-fired generation and build substantial renewable resources, the share of overall energy costs attributed to the Global Adjustment has grown substantially, so that it now accounts for over 85% of the overall

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[13] "Energy Market Regulation in Alberta," November 13, 2014, http://callmepower.ca/en/ab/energy-markets/market-regulation.
[14] The Brattle Group, "Evaluation of Market Fundamentals and Challenges to Long-Term System Adequacy in Alberta's Electricity Market: 2013 Update," March 2013, at 17-28. "Alberta has seen new generation capacity addition of over 9,000 megawatt (MW) since 1998." Alberta, "Electricity Supply," http://www.energy.alberta.ca/electricity/682.asp.
[15] "Q3/2014 Quarterly Report, July – September 2014," Market Surveillance Administrator, November 6, 2014, p.1. http://albertamsa.ca/uploads/pdf/Archive/00-2014/2014-11-06%20Quarterly%20Report%202014%20Q3.pdf.
[16] "Q3/2016 Quarterly Report, July – September 2016," Market Surveillance Administrator, October 31, 2016, p. 3. http://albertamsa.ca/uploads/pdf/Archive/0000-2016/Reports/2016%20Q3%20Quarterly%20Report.pdf.
[17] Alberta's energy market HHI has trended down slightly since 2006. Market Surveillance Administrator, "Measuring Generator Market Power," October 31, 2012, http://albertamsa.ca/uploads/pdf/Archive/2012/SOTM%20Market%20Power%20103112.pdf, at 8-9.

energy price.[18] At least Ontario, unlike Alberta, has a means for recovering these costs and, therefore, a means for making this energy supply transformation.

And fourth, the recently approved procurement program for renewable generation sends a strong and problematic signal to the market. Alberta is committing to making non-energy-market payments to renewable generators under long-term contracts to get substantial amounts of new generation built. To potential investors in conventional generation, this is a serious threat. They will consider the likelihood that prices will not be allowed to increase naturally to the price associated with voluntary new entry. Instead, such side payments could spur new investments and prices will be depressed for a very long and uncertain period. Even if prices rise for a short period, this potential subsidized entry of renewable generation will discourage non-renewable investments. This has been a major problem in balancing the needs of renewable and conventional resources in all of the U.S. markets. It even calls into question the Alberta standard of fairness: Investors thus far made investments on the basis of full participation in electricity markets where they will enjoy the higher prices necessary to encourage new investments where needed. Now that some new entrants get additional payments, we expect they will argue that this results in distorted prices and compensates them unfairly for their investments.

And even if these four issues are not immediately affecting prices, investors will make decisions based on their expectations for the future. These issues will be problematic.

III. There are two general options going forward, either based solely on short-term markets or one where long-term contracting plays a critical role

The GoA stated clearly in its January 26, 2016 letter to the AESO that it has, "not chosen to fundamentally alter the current wholesale electricity market structure." Our conclusion, however, is that continuation of the status quo on electricity market design is not possible. Having made a firm commitment to endorse and support renewable generation through extra-market means, the repercussions are unstoppable and major changes are inevitable.

Alberta could build on its success with short-term market dynamics, with changes made as necessary to incent renewable generation and otherwise maintain a reliable system. There are markets elsewhere committed to this approach. Or, the Alberta market could be transformed to one that fully embraces long-term commitments for key parts of its market structure for all generators, which can be combined with short-term pricing.

Even the threat of a change in market rules may be enough to discourage new supply.

It may seem that this is a continuum, where the decision to allow for some long-term pricing might be made on a gradual basis, with some room for a middle ground. Alas, this is not true. In order for the short-term pricing approach to work, investors need to be confident that future short-term prices will reflect supply and demand. Additional payments to some segment of generators disrupt this balance. Even the threat of such a change may be enough to discourage new supply. No investor wants to make major investments in the hopes of making a profit from hourly energy prices only to find out that later investors receive additional payment such that the hourly prices never rise to the level needed for investment.

We discuss each option below. This is not meant to be an exploration of the concepts and there remain many variations in how they could be deployed. It is sufficient, however, to outline important differences and allow for a comparison between the approaches. We then discuss how the options should be evaluated, consistent with Alberta's requirement for fair, efficient and open competition. As part of that assessment, we emphasize the desire to provide reliable service at the lowest cost.

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[18] Through September 2016, the Ontario Independent Electric System Operator reports that the Global Adjustment is 9.47 cents/kWh out of a total cost of 11.10 cents/kWh for Class B customers (typical homeowners and businesses). IESO, "Monthly Average Hourly Prices, By Year," http://www.ieso.ca/Pages/Power-Data/Price.aspx#GA.

a. Long-term contracting option

In one form of a long-term contracting market, energy markets (for hourly delivery of MWhs) would continue to provide incentives for dispatch. With prices clearing at the marginal cost of the marginal supply source, energy markets provide substantial contributions to generators' bottom line. And similarly, revenues would be obtained for ancillary services as needed by the market. These revenues, however, are not expected to be sufficient to get new generators added when needed by the system. So, what sets this approach apart from the short-term market is a willing buyer who will contract for new supply by committing to additional payments for a long-term period. These payments will be made under long-term contract, with open competition used to obtain these commitments at the lowest cost. The contract would specify the availability of capacity to the system, along with any other attribute that may be appropriate (and could vary among contracts).

One obvious advantage of the long-term contracting approach is that the supplier can use these contracts to demonstrate to lenders greater surety of income, which will lower borrowing costs and drive down the cost of electricity. This is a direct and obvious benefit with substantial value that, as a result of competitive procurement, gets passed directly on to consumers.

Lower borrowing costs are a direct and obvious benefit of long-term contracting that gets passed directly on to the consumer.

There are other advantages. The needs of the system can be targeted. One critical attribute specified in the contracts would be the environmental attributes needed to meet Alberta's goals. There is room for flexibility, but attributes could include a specified share for wind power, another for solar, and potentially other renewable fuels. And the timing of the new additions could be spread out in a planned way to reach long-term goals in a reasonable manner.

Other attributes could include things like energy storage, ramping capability, locational advantages and power quality. In all of these cases, when there are needs, the engineers can see the problem directly and specify what is needed to fix it. And in each case, short-term markets do a poor job of providing incentives for the needed investment. So, while volatile prices are an indication that energy storage and ramping capability might be needed, once those investments are made, the excessive volatility goes away. Similarly for locational generation needs: price difference may indicate transmission congestion, but once the new generation is added, the price differences go away.[19]

Contracts can also be targeted for timing issues. When one large generator is facing retirement, it can have contracts in place that specify the retirement year, both assuring adequate compensation up until that date and then giving the purchaser the knowledge of when replacement is needed and the ability to contract for its construction.

Under this approach, the purchaser would be required to have a portfolio of resources that meet overall goals for supply to ensure system adequacy, as well as all of the other attributes. Some of these contracts could be very long term, supporting new construction with 20 or 30 year contracts. And some would be very short-term, perhaps one or a few years. The purchaser would manage this portfolio, in some ways similar to how a fixed income fund manages bond maturities, so that the portfolio always has enough supply in the very short-term, with that amount decreasing out into the future to allow greater flexibility.

The purchaser needs to be an entity that can make long-term commitments on behalf of consumers. One option is a government agency. This entity would have some parallels with the Ontario Power Authority in that province. That is not the ideal structure, however, because a single buyer creates monopsony market power problems, particularly with respect to purchases from existing generators.

Another alternative is to rely on a modest number of intermediaries, each with an obligation for a fixed group of customers. The existing distribution utilities, perhaps with additional buyers serving very large industrial customers, could serve

[19] It is understood that a goal of the Alberta system is to not have internal transmission congestion in the first place.

this function.[20] Those distribution utilities would effectively, and collectively, take responsibility for ensuring the overall system has enough supply resources. If formally given this responsibility, the distribution utilities would be in a position to contract for supply, manage portfolios and recover the costs from customers.

b. Short-term market option

Alberta today relies primarily on the short-term market option, particularly with respect to the addition of new generation.[21] We have discussed above the inherent problems associated with incenting renewables with long-term price guarantees while relying entirely on short-term prices for the rest of the market. The alternative approach to long-term contracts discussed above is to rely exclusively on short-term compensation. Renewable energy requirements, and markets for renewable energy credits, could be established on a yearly basis. Renewable resource developers generally abhor this approach and declare there is a need for long-term price guarantees for project development and financing. These concerns are valid, but dealing with them in isolation is not. Instead, all of the market concerns discussed above should be considered. These include the need for renewable energy investment, the need for various other investments to ensure reliability, and the need to provide incentives for new investments generally that can meet demand overall.

We start by considering the direct consequence of energy-only markets that Alberta is already facing. When market design features increase risks to suppliers unnecessarily, the cost of borrowing is inflated and costs increase. This has already occurred, with reduced ability to borrow, particularly on a project finance basis. Yes, those firms with balance sheet financing available may still invest, [22] but that is at a higher cost which is passed on to Alberta customers. Too often in evaluating market performance the question stops with whether financing is possible, rather than whether the cost of financing is higher than it needs to be. This is equivalent to deciding a restaurant is good merely because it provides enough calories.

One approach to try to resolve this involves scarcity pricing, and otherwise finding ways to drive up prices during near-shortage conditions. Alberta already does some of this, with prices spiking in periods of near shortage conditions. This is clearly a beneficial dynamic in general, with strong incentives to perform when energy is most critically needed. But, if this mechanism is the primary means by which the system is kept in balance, there are problems. Short-term shortage conditions can result from all kinds of changes to the market, including poor predictions, economic boom cycles, and random performance problems at large generators. High prices might be prevalent in some years, then missing entirely in others. This leads to year-over-year volatility that is highly uncertain for lenders. And lenders are far more interested in prices during lean years than in the rich ones that predominantly reward equity.

There are also market power problems in periods where conditions are so tight that hair-trigger changes in output can dramatically increase prices. In addition, while the number of such shortage hours needed to ensure recovery of investments might be calculable, in actual practice, shortage conditions in some years might occur in a great many hours, leading to huge price increases for consumers, windfalls to generators and complaints of abuse from all sides—including politicians more interested in consumer relief than long-term market design stability.

The more common approach to dealing with incentives for adequate resources is to establish a centralized capacity auction market. These auctions require a uniform product, typically the ability to generate a MW of energy on demand for a one-year period. The system operator generally takes bids

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[20] Taken to the extreme, and to a point not specifically advocated here, the distribution companies could return to a form of vertical integration. Generator resources could be obtained competitively and the province-wide system could be dispatched centrally.

[21] In establishing the Alberta market, long-term power purchase arrangements were put in place that had the potential for additional compensation if energy market prices fell too low. In recent years, this has occurred and these arrangements are in litigation. The critical issue with respect to the concepts in this paper are the incentives for new investment, and those arrangements (and associated litigation) do not play a major role in that process.

[22] The Brattle Group, "Evaluation of Market Fundamentals and Challenges to Long-Term System Adequacy in Alberta's Electricity Market: 2013 Update," March 2013, at 13-17.

from suppliers and then clears the market based on the expected needs of the entire market. The price the system operator is willing to pay is based on the cost of new generator construction (levelized over time), higher in lean years, but then much lower in years of surplus. The price paid by the system operator is dictated by an administrative demand curve and there are many market behavior rules adopted in an attempt to get pricing under this procurement process to behave as desired.

Where adopted, these centralized auction markets have had many problems and have been in a constant state of upheaval and change. There are substantial market power problems on both the buy and sell side, volatile prices, endless rule changes, and many complaints.

Turning consideration to renewable energy, it is relatively easy to establish yearly renewable energy requirements and a system of tradable renewable energy credits where prices are set based on supply (from investments) and demand (in proportion to energy demand). The operation of the market is straightforward, but then, so too are the problems. Just as with capacity markets, there is demand for a product that has nearly zero marginal cost in the one-year over which it is produced, and demand that is very strong up to a threshold, with little-to-no value beyond. This creates a market dynamic of extreme volatility, unless there is further market intervention.[23]

This price volatility can be dampened through strategies such as demand curves for renewables, but all the same problems arise. The other alternative, which is obvious to advocates of renewable energy policies, is to adopt long-term pricing. Most environmental advocates strongly support the long-term approach because it accomplishes the objectives. Developers like it as well, because it allows them to conduct business with success. All of this makes sense, except for limiting the long-term option to only renewables.

IV. Evaluating the options

In evaluating market reforms and options going forward, a critical question is the standard by which options will be measured. The principles of FEOC provide a framework. Open competition is critical, as that can assure the forces of competitive markets will be used to drive down costs and reward innovation. There is more than enough history to demonstrate that a process of writing blank checks to monopoly providers does not serve customers well.

A commitment to competition does not point to a single market design.

Open competition can be adopted under either the short-term or long-term framework.

A commitment to competition does not point to a single market design, however. And fairness is also crucial. As we understand it, that objective of fairness provides another lens upon which to assess open competition and the ability of all participants to be treated reasonably in the market. Thus, open competition and fairness can be achieved under either the short-term or long-term framework.

This leaves the last guidepost of efficiency. The literature on market efficiency typically focuses on the availability of information and the desire that an ever-changing market price always reflects everything that is known about a commodity. That emphasis is not particularly relevant to the issues discussed here. Instead, we posit that the evaluation of efficiency should address whether the needs of the market are being met at the lowest cost. Taking the consumers' perspective is appropriate because whatever the market design, as long as it is openly competitive and fair, prices will be driven down to the suppliers' marginal cost of supply, including a competitive return on investment.

To maximize efficiency, suppliers should not face undue or unnecessary risks or obligations that will increase their costs. And this is not because they will bear those costs. No, in a competitive market consumers effectively pay all costs of the successful suppliers. If market design forces unnecessary costs on suppliers, those costs get passed along in the price to consumers.

[23] The act of setting up the market in the first place is an act of intervention because demand is set administratively, and the product exists only through administrative rules: a consumer has no way of determining the extent the electricity delivered to the meter is produced from renewable resources.

Turning to an example relevant to these markets, when market design increases the cost of financing for all suppliers, the price of electricity will increase and costs to consumers will rise. This could result from a variety of market issues, with one possibility being unreasonable and excessive regulatory uncertainty, in which case lenders will more heavily discount future cash flows and generally lend less money at a higher cost. The market is not efficient. That market could still be openly competitive and fair, just inefficient. And consumers will bear that burden. The efficiency measure cannot be evaluated in the abstract, but only in comparison among alternatives.

Both the short-term and long-term market approaches rely on open competition and both can be more fully developed in a manner that meets the fairness requirement. In terms of efficiency, the long-term option is best able to attract low-cost financing for substantial benefits that consumers can literally and figuratively, "take to the bank." The savings are real and there need to be compelling reasons to adopt any other approach. The long-term contracting option also has tremendous flexibility for addressing all kinds of specific generation attributes, such as ramping rates, location, in-service date timing, fuel diversity and operating range.

One concern with longer contracting is that risks are placed on consumers that would more appropriately be placed on suppliers. These would be risks tied to the long-term nature of the commitment, such as obsolescence, changing demand, and economic obsolescence, or shifting environmental policy objectives.[24] These are legitimate concerns and in concept might be better managed under short-term markets. The critical issue is to determine the extent to which action might be taken by the most innovative supplier to manage the risk, thus giving consumers the benefit of competition.

Take, for example, overall demand for electricity generation. For over a century, demand has grown, most often year-over-year, although there can be the occasional reduction due to economic downturns. With increasing emphasis on demand side management and conservation, the frequency of such reductions might increase. But, by far, the greatest factor contributing to shortages and excess has been the timing of new construction and retirements among generators in the market. Thus, long-term demand is very certain, but there are vagaries in supply and demand that can lead to one-year anomalies. Turning to consumers, under long-term contracting, they can lock in the lowest prices for generators and deal with cost variations tied to the level of excess. If there is an extra 2% of generation in the marketplace due to unexpected imbalance, costs will be 2% too high. Alternatively, under short-term pricing, they will shift this risk onto suppliers across the entire industry. Prices will be volatile, borrowing costs will go up dramatically, and all of that cost will be passed onto consumers. And, when the market is a little short, the price spikes they face will be across the entire portfolio, limited only by the rules in place at the time (and possibly changed afterward due to political outrage).

The market design choice that incorporates long-term contracting is also best suited to dealing with other social policy goals. Issues like retirement planning of resources, job training and benefits for displaced workers, and other resource attributes can be incorporated into the long-term contracts for supplies. Where costs are incurred outside of the domain of competitively-bid generator supplies, they can be passed on to customers along with those generation costs.

In the comparison between the short-term auction markets and long-term contracting, complaints will be raised about the need for markets, as if competitive bidding on contracts of longer duration, with varying product needs, is somehow not a market. Of course this is not true. In fact, electricity stands apart from virtually every industry because of the heavy hand of the system operator in controlling the real-time balancing and reliability of the system. The appeal of centralized auctions and short-term prices is based on the illusion of a competitive market. Policymakers need to be wary of the Law of Second Best. Simply because a market looks like an auction, does not mean it procures the necessary services at the lowest cost. Instead of seeking to create structures that look as much like "markets" as possible, the focus should be on creating structures that best harness the forces of

[24] One might question whether long-term contracting also places risks on consumers for issues such as construction costs, long-term operating costs and equipment availability. Those are risks, but the combination of competitive bidding and locking in prices at the point of contracting results in keeping suppliers fully exposed to these risks.

competition and deliver the best outcomes. Those who ignore the Law of Second Best may think that these two goals are one and the same. However, perfectly competitive electricity markets are impossible. There are too many competing considerations, and entry is too lumpy and expensive.

V. Alberta's path forward needs to be determined by policymakers

There is a strong preference, for good reasons, to rely on markets to deliver the products desired at a reasonable cost. And there is no doubt that market forces and competition will be critical to Alberta's electricity sector growth. But without further direction from policymakers in the form of market design and regulatory changes, the objectives outlined for Alberta will simply not be met.

In choosing among alternatives, care should be given to ensuring the options chosen best meet the policy needs at the lowest costs. And as part of that evaluation, it is easy to become distracted by the visible trappings of auctions and centralized pricing of uniform products. Those elements, however, do not ensure—in fact may have little to do with—the procurement of electricity service at the lowest cost.

This paper assesses the various means that might be adopted and draws a bright line between those short-term markets with the visible trappings of centralized pricing, and a longer term, decentralized, structured procurement process. The differences are clear, both in how they are structured and in their outcomes.

A decentralized process with flexible contract durations and varied products will still rely on competition to obtain services at the lowest costs. And by allowing for tailored products, what is obtained is not set by arbitrary rules needed to run a centralized auction, but simply the products needed to serve customers. It has the potential to lower costs and provide better service, as procurement shifts to meet the needs of the system over time.

This approach also allows for the procurement of services and recovery of costs that would be severely challenged in a short-term market. This includes the need to recover transition costs, such as for retraining and retirement--for instance, dealing with local costs and issues.

Going forward, Alberta obviously will need to create mechanisms by which existing coal-fired generating stations retire and are replaced by other generators, largely renewable resources. In this process it will also encounter other issues. Those will vary with circumstances. Just as a sampling, they could include things like dealing with transitional supply and short-term shortages, the need for fast-responding capacity in locations where it will back up the interties, short-term responsiveness that could be most economically supplied by battery-like resources, and the need to finance critical long-term resources for the lowest cost over many years. These kinds of problems can be obvious to the system operators, yet developing short-term price signals that provide incentives for some supply, but not too much and at not too high a price, can be daunting. After 130 years of market development, the evolution of the short-term market process has reached the point where obvious problems, with obvious solutions, cannot be solved.

Policymakers need to be wary of the Law of Second Best. Simply because a market looks like an auction, does not mean it procures the necessary services at the lowest cost.

The alternative is a system based on flexible contracts, long-term when appropriate, that procures the desired resources when needed at a competitively determined lowest price. It has worked for a century in this industry, as well as virtually every other, and can be used in Alberta to achieve the desired transformation.