THE ALBERTA ELECTRICITY MARKET: STRUCTURING FOR COMPETITION

Report to

Canadian Competition Bureau

Larry E. Ruff, PhD

March 6, 2002

THE ALBERTA ELECTRICITY MARKET:
STRUCTURING FOR COMPETITION
Table of Contents

THE ALBERTA ELECTRICITY MARKET: STRUCTURING FOR COMPETITION

Report to Canadian Competition Bureau

Larry E. Ruff

March 6, 2002

1. INTRODUCTION AND SUMMARY

1.1 THE ALBERTA CONTEXT

The Alberta Department of Energy (DoE) is conducting an Electricity Industry Structure Review (the Review) that is analyzing alternative ways to structure the centralized market institutions in Alberta. As part of the Review, the DoE commissioned London Economics International LLC (LE) to prepare a series of working papers culminating in a Final Recommendation,[1] and has invited interested parties to comment on these LE papers.

This report has been commissioned by the Canadian Competition Bureau (the Bureau) to analyze the competitive implications of the system coordination and pricing issues raised by the LE papers. The focus is on LE's Final Recommendation, but several LE working papers are also considered because they "are an integral part of the process and provide context for the recommendations laid out in" the Final Recommendation [p. 1]. The views expressed here are those of the author and do not necessarily reflect the views of the Bureau.

The current Alberta electricity market divides responsibility for system control and spot pricing among three distinct entities: a System Controller (SC) that manages real-time operations; a Pool Administrator (PA) that operates a Real-Time Market (RTM); and a Transmission Administrator (TA) that – among other things – is financially responsible for transmission losses and congestion, and procures reserves and ancillary services. In addition, the Market Surveillance Administrator (MSA) and an Alberta-specific entity called the Balancing Pool (BP) are both within the Power Pool of Alberta (PPoA) that contains the SC and the PA/RTM.

[1] "Final recommendations regarding the evolution of electricity industry structure in Alberta," January 10, 2002. All page references in this report are to the Final Recommendation unless otherwise indicated. The principal working papers of interest here are the report on the Transmission Administrator and System Controller dated September 7, 2001 (LE TA&SC report), the Briefing Note dated September 26, 2001 (LE Briefing Note), and the report on the Pool Administrator dated August 24, 2001 (LE PA report).

This report focuses on issues involving the TA, SC and PA/RTM because these institutions and their functions jointly determine the efficiency of system operations and pricing. The MSA and BP are not discussed here, although the author of this report agrees with the conclusion of most other commentators including the Bureau and LE, that the MSA and BP should be organizationally as well as functionally separated from the system control and pricing functions.

1.2 THE PREMISES OF THIS REPORT

The analysis in this report is based on the two general principles and two specific realities of electricity systems summarized and discussed below.

Principle 1: Form (or structure) should follow function.

Reality 1: The functions that must be performed centrally in an electricity system are complex, specialized and largely "real time."

It follows from the above that any effort to design or redesign the centralized institutions in an electricity market should be based on a sound understanding of the complex real-time coordination functions that must be performed centrally and on a careful analysis of how alternative structures would actually perform these functions.

Principle 2: Competition can be effective and efficient only to the extent that market prices internalize marginal[2] costs and benefits.

Reality 2: In electricity, significant marginal costs and benefits arise from the real-time management of imbalances and transmission congestion.

It follows from the above that competition in electricity will be effective and efficient only to the extent that market prices reflect the sometimes large and always volatile and unpredictable marginal costs resulting from the real-time management of imbalances and transmission congestion. If effective and efficient competition is the objective, alternative market structures and processes should be analyzed and compared in terms of their ability to produce market prices that internalize real-time operating costs.

Consistent with the above logic, this report outlines the basic functions that must be performed in any electricity system, discusses which of these can be decentralized and which must be centralized, and describes how the organization of the centralized functions might affect the efficiency of real-time operations and pricing. It then recommends that Alberta adopt a structure that can efficiently manage real-time operations and accurately internalize real-time system costs in market prices. Issues of governance and incentives are also discussed as factors to be considered in the final design, but as the tail, not the dog.

---

[2] The emphasis here is on *marginal* costs and benefits because these are what should determine prices and incentives.

1.3 Summary Recommendation and Its Basis

The basic recommendation of this report is that:

Alberta should adopt a market structure that can facilitate (and will ultimately operate) an integrated system control/spot pricing/congestion management process; for this purpose, an ISO (Independent System Operator[3]) structure is best for Alberta.

This recommendation is supported by analysis and practical experience demonstrating that:

- An integrated system control/spot pricing/congestion management process maximizes the role of decentralized markets and minimizes the role of centralized monopolies – e.g., the SC and TA in Alberta – by using market forces to manage real-time imbalances and congestion and using the results of real-time operations to produce market prices that reflect or internalize real-time costs; conversely,
- Separating system control from energy (and reserve and ancillary service) "spot" markets requires that real-time imbalances and congestion be managed by inefficient non-market methods, and results in market prices that do not accurately reflect or internalize the resulting costs, requiring more direct intervention in both short-term operations and long-term investment by monopolies such as the SC and TA.

1.4 The London Economics Analysis and Recommendations

The LE recommendations that are most important for system operations and pricing are in direct conflict with the recommendation and analysis summarized above.[4] Adoption of the LE recommendations would make it difficult or impossible for Alberta to adopt the market model that is rapidly becoming standard in the United States and elsewhere – an ISO-operated integrated system control/spot pricing/congestion management process that uses locational marginal prices (LMPs) to internalize real-time congestion costs.[5]

In particular, the Final Recommendation proposes that system control, spot pricing and congestion management be in three different entities – a System Controller (SC), a Pool Administrator (PA) and a Transmission Administrator (TA), respectively. This structure, viewed from the high level of an organization chart, might not totally preclude the SC, PA and TA from cooperating to implement an integrated system control/spot pricing/congestion management process. But the Final Recommendation proposes governance and managerial arrangements that appear explicitly designed to prevent such a result.

[3] In this report, any system controller unaffiliated with market participants is called an "ISO" even though it may be, or may be part of something, called a pool, a regional transmission organization (RTO), a Transco, a SC or something else.

[4] The only exception is the LE recommendation to combine some of the operational responsibilities now divided between the TA and SC.

[5] See "LMP Rapidly Becoming SOP," Platts Energy Insight, February 11, 2002.

In the Final Recommendation structure, the SC and PA would both be "nominally" [p. 5] within a statutory Power Pool Corporation – basically a modified PPoA[6] – but would have separate staffs, CEOs, incentives and reporting arrangements, and would be required to deal with each other at "arms length" [p. 5] and subject to a "code of conduct." [p. 25] The TA would be under contract to, but would also "run," [p. 30] a separate statutory entity called the Standing Transmission Organization (STO). The STO/TA and Power Pool Corporation would both report to a stakeholder-elected Alberta Power Pool and Transmission Council (APTC), but their interactions would be limited to "informal discussions" to assure information "systems compatibility." [p. 7] These arrangements would effectively preclude operation of an integrated system control/spot pricing/congestion management process.

The Final Recommendation's proposals to separate system control, spot pricing and congestion management more than they now are in Alberta are based largely on the governance, managerial and incentive benefits of organizational decentralization. For example, the recommended fragmentation is said to produce "strong, free-standing organizations" that can "focus on their core competencies" [p. 3] and be "champions" for their respective areas of responsibility. [p. 25] But LE does not describe specific governance, managerial or incentive benefits of fragmentation or how these might be achieved. Indeed, as discussed in section 3.6 below, the recommended structure and managerial relationships are likely to have the opposite of the desired and claimed effects when compared to the alternative of an Alberta ISO.

1.5 Comparison to Experience and Developments Elsewhere

The LE working papers and Final Recommendation say little about operational and pricing matters, so a detailed analysis and critique on this level is not possible. It is possible, however, to point out that others have tried to separate electricity system operations from spot markets as proposed in the Final Recommendations, but with little success either in theory or in practice. The technical and economic reasons why this is so are discussed in section 2 below. The real-world evidence demonstrating this is summarized below.

- The original California wholesale market design tried to separate operations from the market, much as recommended for Alberta by LE. The resulting system created such serious problems that the US Federal Energy Regulatory Commission (FERC) called it "fundamentally flawed" and ordered it redesigned even before the market explosion/meltdown in California. The California ISO recently acknowledged that its previously sacrosanct "market separation" principle was a mistake and is now proposing a fundamental redesign of the wholesale market that would allow the ISO to operate an integrated system control/spot pricing/congestion management process

6 As discussed in section 3.2 below, the earlier LE Briefing Note preferred a "triumvirate" structure in which the SC and PA would be in totally separate organizations with totally separate governance and regulation. The Final Recommendation is to create essentially the same functional separation between system operations and spot pricing but without breaking up PPoA as an organization.

based on some version of LMP, with financial transmission rights (FTRs) to hedge LMP differentials.[7]

- The principal objective of the New Electricity Trading Arrangements (NETA) in England and Wales was to eliminate the central Pool and force all trading into multiple private markets. Even here, however, the National Grid Company (NGC) manages imbalances and congestion using an integrated, centralized, monopoly balancing "mechanism" (BM) that is essentially a very inefficient market designed to penalize imbalances. The resulting bias against undiversified cogenerators and independent retailers is causing some of NETA's original proponents and strongest defenders to suggest that the BM be modified so that it is more like a real-time energy market.[8]
- The most successful functioning electricity markets around the world, such as PJM (the market system for Pennsylvania, New Jersey, Maryland, and some neighboring areas), New York, New England, Australia, Norway, Argentina, New Zealand[9] and others, are based on integrated system control/spot pricing/congestion management processes, most using some version of LMP and FTRs. Such ISO-operated markets are expanding and integrating to create larger and more efficient markets.
- Some embryonic Regional Transmission Organizations (RTOs) in North America – including RTO West and others cited by LE in support of its recommendations – have tried to find some way to separate system operations from energy markets but have yet to do so and many/most of them are now giving up. Where the objective is to create rather than delay effective competition, most RTOs are moving toward ISO-operated integrated system control/spot pricing/congestion management processes in real time (and sometimes an hour-ahead and/or a day ahead as well), in most cases using LMP and FTRs to price and manage the risks of congestion.[10]

---

7 California ISO, Market Design 2002 Project (MD02), "Preliminary Draft Comprehensive Design Proposal," January 8, 2002, and "Revised Draft Comprehensive Design Proposal and Project Time Line," January 28, 2002. Available on CAISO web site.

8 Stephen Littlechild, "Electricity: Regulatory Developments Around the World," [Beesley Lecture], Institute of Economic Analysis/London Business School, London, revised version, November 12, 2001.

9 LE suggests that New Zealand is an example of a system in which the system controller "does not provide a pool or power exchange." [LE TA&SC report, p. 17] As discussed in section 2.4.2 below, New Zealand uses an integrated system control/spot pricing/congestion management process based on LMP of the type recommended in this paper for Alberta.

10 Both SE-Trans (a RTO in the Southeast US) and MISO (the MidWest ISO) are now proposing a RTO/ISO-operated real-time market using LMP; indeed, MISO has signed an agreement with PJM to develop a single market based on the PJM LMP model. The Alliance RTO has been ordered by FERC to join MISO; if this order is maintained on appeal, the Alliance will also have to implement a RTO/ISO-operated LMP market. RTO West has given up on the "flowgate" approach to congestion management, a sure precursor to acknowledging the need to integrate operations and a spot market. ["Restructuring Today," January 24, 2002]

- FERC is considering, and is expected to adopt, a "standard market design" for RTOs that includes an integrated RTO/ISO-operated system control/spot pricing/congestion management process with LMPs and FTRs.[11]

In short, LE's recommended separation of system control from spot market pricing from congestion management can find little or no support in the experience with electricity markets around the world. Within a few years, ISO-operated markets based on an integrated system control/spot pricing/congestion management process – the kind of market that would be essentially precluded by the Final Recommendation – are likely to be operating in an integrated manner across much of the United States. The technical and economic reasons why this is so are discussed in the next section.

2. FUNCTIONS AND STRUCTURES IN ELECTRICITY

There are certain functions that must be performed in any electricity system, whether or not some of these functions are competitive. This section discusses the errors that can be made in deciding which functions can and should be turned over to competitive markets and which should be regarded as monopoly infrastructure functions, describes the basic functions that must be performed in any electricity system, and then outlines the basic alternatives for organizing the monopoly infrastructure functions.

2.1 WHAT SHOULD BE COMPETITIVE AND WHAT SHOULD BE MONOPOLY?

Either of two types of error can be make when deciding whether some function should be performed by a monopoly or turned over to competitive markets.

- **Type 1 Error: Letting a monopoly control an inherently competitive function.** This type of error limits the scope of competition and hence reduces the potential benefits of competition. The cost of this type of error can be high if the monopoly or its regulation is very inefficient but is less if the monopoly and its regulator are doing reasonably good jobs.

- **Type 2 Error: Forcing competition in a natural monopoly function.** This type of error results in loss of the economies of scale and scope that define a natural monopoly function and – because real competition in a natural monopoly function is impossible – usually results in an unregulated oligopoly rather than real competition. The cost of this type of error can be very high if a natural and reasonably efficient infrastructure monopoly is replaced with a few duplicative and undersized oligopolists.

The dividing line between naturally competitive and natural monopoly functions is fuzzy, because some functions share characteristics of both. But in the zeal to create competition

[11] See "Restructuring Today," January 24, 2002.

and under pressure from potential competitors, policy makers and regulators often underestimate the probability and potential costs of Type 2 errors. The mere fact that some firms want a monopoly prevented from providing some service so that they can compete with each other to do so does not prove this would be a good idea. There are always many firms eager to try to become one of a few unregulated oligopolists, even if the result is undersized, inefficient and duplicative firms, higher transaction costs for market participants and ultimately higher prices and/or inferior service for consumers. Some functions really are natural monopolies, and forcing such functions into the competitive market is not good for consumers or the economy.

Electricity involves many complex functions that must be either kept as monopolies or turned over to competitive forces. Virtually any of these functions, even those with clear natural monopoly characteristics, could be made competitive at some cost. For example, a law prohibiting any transmission company from owning more than one hundred miles of contiguous transmission lines or engaging in any other business might result in many strong, focused transmission companies, each an efficient, innovative and profitable champion for its core competency of building, owning and operating one-hundred-mile transmission lines. But consumers and the economy as a whole would pay a high price for such artificial competition.

Nobody seriously proposes forcing artificial competition in transmission for the sake of competition or competitors, because transmission is so obviously a natural monopoly.[12] But other natural monopoly functions are less obvious, and for these there is often strong pressure to force competition for its own sake or for the benefit of competitors without adequate regard for the effects on overall efficiency and ultimately consumers. This is particularly true for trading and pricing processes that cost little compared to final electricity prices but have strong natural monopoly characteristics and/or must be integrated with system control functions if they are accurately to internalise the costs of complex system effects. Forcing competition in these market processes can produce high margins for a few unregulated market makers and exchanges, but at high cost to system efficiency and consumer prices.

Electricity market designers should never forget that the ultimate objectives of competition are sustainably lower costs and better service for consumers, not competition for its own sake or for the sake of competitors. Luckily, most of the costs of delivered electricity are in the naturally competitive generation and (to a much lesser extent) trading functions, so the best way to assure that competition lowers costs for consumers is to assure that critical infrastructure monopoly functions are provided in an efficient, non-discriminatory manner to all competitive generators and traders. Competition in the infrastructure functions

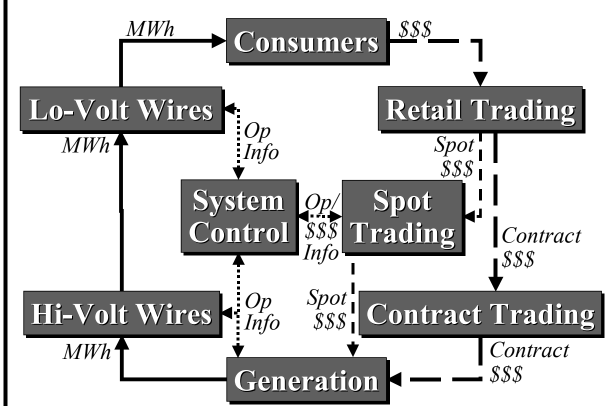
12 This is not to say that all transmission must be built, owned and operated by a monopoly. Even a monopoly should, where it is cost-effective to do so, contract out, unbundle and price individual services so that others can compete to provide these. There is even a role for "merchant" transmission projects in specific cases, although these will probably never displace the core transmission monopoly.

themselves is a nice bonus where it can be achieved efficiently, but is counterproductive if it results in duplication, confusion and high transaction costs for system users, and particularly if it reduces the efficiency of operations and the ability of market prices to internalise costs.

2.2 The Basic Functions in any Electricity System

Figure 1 illustrates the basic functions that must be performed in any complex electricity system. This figure separates the physical functions on the left from the commercial trading functions on the right, and shows in the middle the critical system control and pricing functions needed to link the physical and commercial functions. It does not show the money flows associated with the wire and infrastructure monopolies or customer services such as metering, billing and retail settlements.

Figure 1: The Basic Functions in Electricity



As illustrated in Figure 1, most final consumers get their physical electricity (MWh) from a low voltage distribution system that gets it from or is an integral part of a high-voltage transmission system. These wires functions are inherently natural monopolies within a region, in the sense that it would be very costly to have more than one transmission and distribution (T&D) system in a region and any producer or consumer not connected to that system is at a strong economic and competitive disadvantage.

Generators deliver physical electricity to the high-voltage transmission grid and are paid for it through a combination of contract and spot transactions. Generation is in principle a competitive activity, although in practice limited transmission capacity and inelastic consumer demand can give some generators significant local and temporary market power.

Consumers pay a retail trading entity for the electricity and other services they receive. The retail trading entity pays for electricity through a combination of spot transactions and contract arrangements, perhaps including the long-term contract arrangement of owning its own generation. Retail trading is inherently a competitive activity – if it is adequately unbundled from those customer services that have natural monopoly characteristics – although some regulation is usually called for to protect smaller consumers.[13]

Every electricity system needs a system control or dispatch process to coordinate real-time physical operations. This physical control/dispatch process is inherently a natural monopoly

[13] Consumers might buy their physical electricity from a distribution monopoly at the spot price and then just hedge the spot price with competitive retail traders. In this case, retailers would not actually buy and sell physical electricity but would be pure financial traders and hedgers.

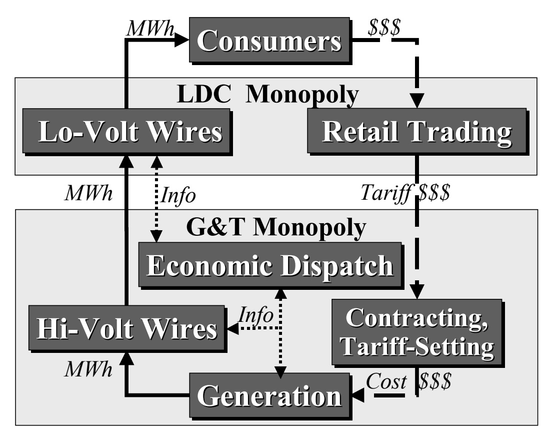
because all system information must be brought together in one location and analysed as a whole, and only one entity can issue operating instructions to each generator (or dispatchable load[14]). Efficient and effective competition requires that all competitors have open access to physical dispatch services for the same reasons they must have open access to wire services: because any competitor without access to those services would be at a serious competitive disadvantage. A major challenge in market design is to find some way to give all competitors equal access to the system control/dispatch process, i.e., to assure that all competitors are treated in a non-discriminatory fashion in system operations and pricing.

A major issue in electricity market design, and the fundamental issue on which this report disagrees with the LE analysis and recommendations, is the extent to which spot trading processes should share operating and pricing information with, or should even be an integral part of, the monopoly system control function. As discussed at length below, both the theory of and experience with competitive electricity markets demonstrate that the system control and real-time trading functions are best regarded as two, inseparable parts of a single, and hence monopoly, system control/spot trading/congestion management process, because this is the best/only way to treat all competitors in an efficient, non-discriminatory way. Contract or forward trading, however, is an inherently competitive process; there can, should and will be many, competitive market-making processes operating prior to real-time to trade and price all manner of forward contracts and risk-management instruments.

2.3 System Control and Pricing in an Integrated Monopoly

Figure 2 illustrates a version of the traditional monopoly ESI in which a generation and transmission (G&T) monopoly owns and/or has long-term contracts with all generating units, and sells electricity to local distribution companies (LDCs) who provide distribution and retailing services to captive consumers. There is no explicit spot trading function, because a monopoly system controller/ dispatcher simply gives orders to the generating units, they respond because that is their job, and all operating costs are pooled within the G&T monopoly and (along with capital costs and "reasonable" profits) are recovered from the captive LDC customers through tariffs. But any reasonably sophisticated ESI uses an economic dispatch process to determine real-time operations that

Figure 2: A Monopoly Electricity Industry



[14] For simplicity, this report uses the term "generators(s)" as shorthand for "generator(s) and/or dispatchable load(s)" where the context so suggests.

(approximately) minimize the cost of meeting demand given real-time conditions and system security constraints including transmission constraints.[15]

The logic of a sophisticated economic dispatch process is essentially the same as the logic of a competitive market operating on a complex grid with well-defined transmission rights, and the mathematics of the process logically produces implicit prices for energy (and other things) that reflect the complex and rapidly-changing factors – including transmission congestion – that influence real-time operations. Such a process uses the best information available about generating unit costs, demand and the physical system in a single, integrated process to determine reliable and efficient system operations and the implicit prices reflecting the actual outcome. These prices can be and often are used to give operating signals to individual generating units telling them how to modify their operations in real time so that total demand is met at least cost subject to the actual real-time constraints.

Any economic dispatch process is imperfect and approximate, but virtually nobody seriously argues that a competitive market is likely to be better at coordinating a given set of resources efficiently. It is so hard to get accurate information from, and to control the actions of, many independent, profit-seeking generating units that a market-based system control process will almost always be less efficient in this sense than a good monopoly dispatch process.

The realistic expectation/hope for competition is that, in the longer-run, it will increase the availability, flexibility and cost characteristics of the generators and loads enough to offset the likely inefficiencies introduced into the short-run system control/dispatch process. But this will be true only if the real-time coordination process in the competitive electricity market is at least almost as efficient as central economic dispatch in the short run and – more importantly – provides market prices that motivate market participants to make longer-term investment, maintenance and availability decisions that result in a better set of resources being brought to the market every day. The biggest technical challenge in designing and implementing a competitive electricity market is to find dispatch and market mechanisms that can accomplish these objectives.

2.4 General Considerations in Wholesale Unbundling

Figure 3 focuses attention on the wholesale market by simplifying the distribution and retailing sector. Of the remaining or wholesale functions, generation and contract trading are in principle competitive activities and hence can be largely left to design themselves, although it may be necessary to control generator market power and to assist the development of contract trading facilities. The really difficult issues concern the relationships between competitive market participants and the system control process, and among the grid, the system control process and spot trading.

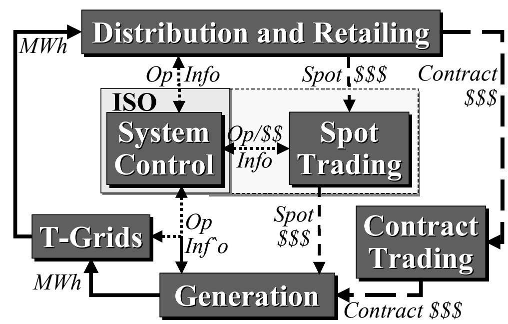
---

[15] Security constraints include not only limits on actual power flows on lines and voltages at locations, but also contingency constraints to assure that the system will continue functioning even after the sudden loss of any one (or sometimes more) generator or transmission line.

2.4.1 RELATIONSHIP BETWEEN SYSTEM CONTROL AND MARKET PARTICIPANTS

It is now generally accepted that the system controller or operator in a competitive market must be independent of any competitive players in the market, i.e., the system control process must be operated by an *independent* system operator (ISO) as shown in Figure 3. Whether the spot trading function should also be part of the ISO is the principal issue in market design and is discussed at length in the next subsection.

Figure 3: The Wholesale Functions



2.4.2 RELATIONSHIP BETWEEN SYSTEM CONTROL AND SPOT TRADING

The relationship between the system control process operated by the ISO and spot trading is the most contentious issue in the design of competitive wholesale electricity markets. In particular, the LE papers recommend structures and processes that appear to be explicitly designed to assure that system control is separate from any market process, while the most important conclusion of this paper is that system control should *be* a market process. This difference leads to very different structural and process recommendations.

The conclusion that system control should be closely integrated with or should actually *be* a market process is based on the fact that system balancing and congestion management are inherently economic problems – or, more accurately, are both inseparable parts of a single economic problem – and that such a complex economic problem is best solved with a market process that produces prices reflecting the solution. Imbalances and congestion require that some generators in some locations produce more than they had planned or scheduled to produce while others in other locations produce less. The fact that there are usually multiple patterns of readjustments that can eliminate system imbalances and congestion, each with different total costs and a different allocations of costs and benefits among market participants, makes this a classic economic problem.

In a competitive electricity industry, the only reasonably efficient and non-discriminatory way to solve the economic problem created by imbalances and congestion, and to allocate the resulting costs and benefits, is with a spot market closely integrated with the ISO's system control process.[16] In such a process: all generators above some minimum size tell the ISO how much they will produce at various prices or – the same thing said another way – how much they want to "schedule" to produce and how much they will (or will not) change their plans and operations at various prices; the ISO selects the set of offers that simultaneously

[16] The LE papers suggest that the main arguments for ISO-operated spot markets are the "economies of scope across the system control, price determination, and transmission operation function." [LE TA&SC report, p. 18] The real reason for integrating dispatch with a spot market is much more fundamental than saving some overhead costs; it is that dispatch is inherently an economic problem that, in a competitive system, should be solved in a market.

balances the system and manages congestion at least cost; market-clearing prices corresponding to this solution are computed; and those who help manage imbalances and congestion are paid the market-determined value of their services while those who contribute to system imbalances and congestion pay the market-determined costs of their actions.

The integration between system operations and the spot market can be accomplished in various ways in addition to having an ISO do it all. For example, a market entity called a "Pool" or "PX" organizationally separate from the ISO can manage information and money flows between market participants and the ISO, or can even take the lead in defining the rules of the integrated system control/spot pricing/congestion management process and can then (in effect) contract with the ISO to operate the system and determine prices according to these rules; this is the approach taken in New Zealand[17] and in England and Wales.[18] It is not critical what names are on how many doors or who is ultimately in charge, as long as somebody is responsible for assuring that behind the doors operational and pricing information is used in an integrated system control/spot pricing/congestion management process.

In practice, the best approach is to acknowledge the reality of the integration and combine the ISO and spot market functions in a single entity, as is done in the ISOs in PJM, New York and New England, in the Independent Market Operator (IMO) in Ontario, in Australia and elsewhere. For this reason, this paper uses the term "ISO-operated spot market" to refer to any integrated system control/spot pricing/congestion management process, even if there is a market entity that is nominally separate from the system controller/ISO.

The principal criticisms of an ISO-operated spot market are that it is somehow "mandatory," it competes "unfairly" with private market makers, and it requires or allows the monopoly system controller to "interfere" in the competitive market. All of these criticisms are fallacies that do not withstand scrutiny.

- **Fallacy 1: An ISO-operated market is "mandatory."** Any electricity market must have technical, information and pricing/settlement rules that apply to all system users. An ISO-operated market is just the most efficient, market-oriented way to define, implement and enforce such mandatory rules. Every well-designed ISO market allows any user to operate independently of the market (subject to the technical limits that must apply to any system) simply by informing the ISO of its plans (e.g., by

---

17 In New Zealand, Transpower (the SC/ISO and grid owner) operates, even if it does not "provide," an integrated system control/spot market process/congestion management process based on LMP. This integrated process is defined/provided by an organization of market participants called the New Zealand Electricity Market (NZEM) that also manages bids/offers, settlements, fiduciary standards, and other commercial matters.

18 Before March 2001, the Pool defined the market and dispatch rules used by NGC to manage dispatch and congestion and to determine Pool prices in an integrated process – albeit one that was crude by current international standards. Even NETA uses a similar integrated process, but with grossly inefficient real-time pricing that forces a lot of forward contracting and even business integration among market participants.

scheduling a fixed amount or by submitting an offer to generate a fixed amount at any price) as long as it pays (is paid) the market-determined costs (benefits) caused by its independent actions. An ISO-operated spot market adds nothing but efficiency and flexibility to the constraints that are mandatory because of the realities of a complex electricity system.

- **Fallacy 2: An ISO market competes "unfairly" with private market makers.** There can be only one system control process in a region, so if this process is to be based on a real-time market there can be only one such market and it must be operated by the ISO.[19] If system control is NOT based on an ISO-operated spot market there will be more decentralized forward trading by market participants scrambling to stay in balance in order to minimize imbalance penalties.[20] But preventing the ISO from operating an efficient system control/spot market in order to stimulate a lot of inefficient forward trading would be like breaking up an integrated transmission grid in order to stimulate a lot of inefficient 100 mile transmission lines. The natural monopolies at the core of an electricity system should be allowed – indeed, required – to be as efficient as possible, not forced to be inefficient for the benefit of competitors and at high cost to consumers and the economy.
- **Fallacy 3: An ISO operating a spot market is "interfering" in the market.** The only way the ISO can manage real-time imbalances and congestion is to get some generators in specific locations to produce more or less energy (and/or reserves and ancillary services) than they would otherwise produce. If the ISO does not use a spot market to affect real-time actions, it has only two basic options for doing so: (1) interfere directly in the market by issuing non-market, uncompensated orders enforced with arbitrarily high penalties; or (2) contract with specific generators (as the TA does in Alberta and NGC does in England and Wales under NETA[21]) and/or own and operate its own generation, in effect becoming a market participant and taking market risks. In the absence of short-run prices that reflect actual operational costs, in the long run the ISO or some other monopoly will have to interfere in the market to influence investment decisions, either with tax/subsidy arrangements (e.g., the TA subsidies used in Alberta to affect generator location decisions) or arbitrary

19 The ISO may contract out some of its mechanical functions to one or more competitive entities, but this does not create more than one market or allow competitors to set up their own dispatch/market processes.

20 The only practical way to operate an electricity market without an ISO-operated spot market is to require generators to schedule their contract operations and then to impose high penalties on imbalances, i.e., on differences between scheduled and actual operations and/or on differences between a generator's actual output and its customers' consumption (adjusted for losses).

21 Forward contracting by the Alberta TA for ancillary services "was met with some concern by market participants because the TA is the only consumer in the market. Participants did not want forward purchases to be so extensive that it reduced liquidity and restricted the development of a competitive market." (LE TA&SC report, p. 6) Long-term contracting by NGC in England and Wales for balancing and congestion management energy is causing similar concerns.

rules (e.g., ISO rules prohibiting generators from locating in congested areas[22]). The best way to minimize the ISO's direct interference or participation in the market in both the short and the long term is to allow/require the ISO to operate an integrated system control/spot pricing/congestion management process.

The view that the ISO should not operate a spot market and should not even cooperate closely with any entity that does so is usually based on some combination of the above fallacies and the commercial interests of potential market makers, arbitragers and traders who make their money exploiting market inefficiency and opaqueness. The most vocal opponents of ISO-operated markets tend to be the exchange operators, energy traders and sophisticated game-players who stand to gain directly from very-short-term forward trading and complicated, opaque physical markets. Such entities had strong influence in the design of the initial California market and of NETA.

Despite the opposition in certain quarters to the idea that the ISO should operate markets, it is now generally accepted that an ISO must use *some* market-like monopoly process to control real-time physical operations, even if it is a highly inefficient and discriminatory market or is not even called a market. For example, designers of the initial California market found it impossible to adhere strictly to their market separation rule and had to let the ISO operate a RTM – albeit a very inefficient and discriminatory one. As another example, the Balancing *Mechanism* (BM) in NETA is the functional equivalent of a real-time monopoly market operated by NGC, just a very inefficient one under a different name. The only issue is whether the monopoly, market-like process used by the ISO to manage imbalances and congestion should be open, efficient and non-discriminatory so that market participants can buy and sell freely at market-determined prices, or limited, inefficient and discriminatory in order to force market participants to enter into forward contracts reflecting their expected operations and then to manage real-time operations to match their forward contracts – a process that increases but hides the costs of managing imbalances and congestion.

2.4.3 Relationship Between Grid Operations and System Control

There is no perfect way either to divide or to combine the responsibilities for grid operations and system operations. The operational interactions between the grid and system control are so complex that any division will to some extent diffuse responsibility and create less-than-perfect incentives. But combining the functions into a single entity creates a large, complex monopoly that is hard to manage and regulate. Pragmatic trade-offs are always necessary.

Even where competition is not possible or desirable, separating regulated monopoly activities can have real benefits if the separated entities have better-defined objectives – more "focus" – outputs that can be measured more accurately, and greater transparency. The problem is

[22] For example, both the California and New England markets initially socialized congestion costs (as Alberta does) and as a result new generation naturally gravitated to a few, convenient locations, creating congestion. Both ISOs tried to forbid new generation from locating in certain regions, but these rules were rejected by FERC as discriminatory. The New England ISO is now implementing a LMP-based system and the California ISO has just proposed something similar.

that separating a complex infrastructure or service function into smaller functions may make it harder, not easier, to define and measure outputs and may create more complexities and externalities among the functions.

For example, the costs of losses and congestion, along with all other operating costs, depend on real-time system operations, so a single entity should be responsible for minimizing total real-time operating costs given the physical assets available. Making one entity – e.g., the TA – responsible for the costs of losses and congestion when another entity – e.g., the SC – is responsible for system control diffuses responsibility and creates perverse incentives on both entities, particularly because there is often a direct conflict between reducing the costs of losses and congestion and reducing total system operating costs.

Although nobody has yet proposed a totally satisfactory way to separate or to combine grid and system operation functions, it is generally accepted that the interactions between the grid and system control *in system operations* are so strong and complex that a single entity should be responsible for all aspects of real-time operations and their effects. The ownership, maintenance and operation of grid facilities can be separated from real-time system operations, because it is relatively easy for the system operator to give operating instructions to the grid operator and to define measurable standards for physical grid performance and operations. Long-term system planning that involves trade-offs between investment costs and operating costs can and of necessity always will be done in processes involving multiple parties outside the real-time system control process. But a single entity – presumably the SC in Alberta – should be responsible for all near-real-time operational decisions and their effects, including losses and congestion.

3. ALTERNATIVE STRUCTURES FOR ALBERTA

This section outlines some alternative structures for the centralized institutions in the Alberta electricity market, particularly those outlined and discussed in the LE working papers and Final Recommendation, and analyzes these in terms of their ability to perform the most critical functions of any such structure – managing real-time operations efficiently and determining system prices that internalise what are otherwise unpriced system externalities.

3.1 The Current Structure in Alberta

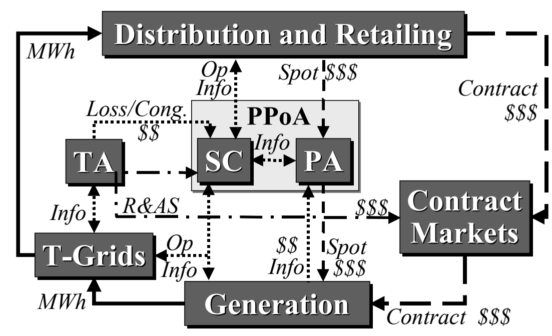
Figure 4 illustrates the current structure of the centralized wholesale market in Alberta. There is a Power Pool of Alberta (PPoA) – sometimes called just "the Pool" or "the Power Pool" – that includes both the SC that controls real-time physical operations and a Pool Administrator (PA) that operates a real-time market (RTM). The TA is a separate entity that is responsible for certain planning and operating functions for the grid,[23] as well as the costs of losses and congestion and the procurement of reserves and ancillary services (R&AS). Contract trading is done through various formal and informal markets outside of PPoA, but

[23] The grid itself is owned by several separate companies.

the TA buys R&AS from one of these external markets (Watt-Ex), with these R&AS then dispatched by the SC based on information from the TA.

Three features of the current structure illustrated in Figure 4 are discussed in turn below: (1) the relationships between the SC and PA within PPoA; (2) the relationships between the TA and PPoA; and (3) the procurement of R&AS.

Figure 4: The Current Alberta Structure



3.1.1 Relationships Between the SC and RTM within PPoA

Although the SC and PA are separate entities within PPoA, their operations are integrated in essential ways. Generators submit their bids/offers to the PA's RTM a day in advance, and the PA uses these to construct an unconstrained[24] merit order or energy supply curve and – in combination with demand forecasts – to forecast Pool prices for each hour of the next day. Much or all of the bid/offer information, plus more detailed information such as plant dynamic constraints, is available to the SC, which updates it with later information on demand and generator availability. In real time, the SC uses the best available information on actual demand, generator availabilities, grid conditions, system security constraints, the energy offer curves from the PA[25] and the R&AS supply curves from the TA/Watt-Ex to determine a more-or-less efficient way to operate the system within system security and generator dynamic constraints. After the fact, the PA uses the operational and updated market information from the SC to determine the *ex post* unconstrained Pool price.

The system control and RTM pricing process currently used in Alberta is not perfect. The SC may not use all generator offers to find a least-cost solution to the balancing and congestion management problems simultaneously, because of software limitations or deliberate constraints intended to let "the market" rather than the SC determine physical operations – the approach that California tried with bad results and NETA is trying now. It is likely that operations and pricing could be significantly improved if the SC and PA jointly operated a single security-constrained dispatch process that determined physical operations

---

[24] An unconstrained merit order indicates which generating units would operate to meet different levels of demand at least total cost if there were no transmission constraints and with other simplifying assumptions related to reserves, etc. The unconstrained Pool price is the offer price of the last or highest-offer-price generator (or dispatchable load) block that would be needed to meet demand under these simplifying assumptions.

[25] As discussed in section 3.2 below, the SC cannot, in general, manage congestion efficiently using only the merit order without offer prices. The Alberta grid may currently be so simple – e.g., with only radial connections between internally unconstrained regional grids – or so seldom constrained that efficient congestion management is not yet important; but this will likely change over time, particularly if spot market prices do not accurately price congestion so that new investment aggravates rather than relieves it.

and LMPs reflecting the marginal cost effects of transmission congestion simultaneously, particularly if the resulting LMPs were used for market settlements. As discussed below, in most cases it would be more efficient to optimize and price energy and reserves simultaneously rather than to buy reserves separately based on supply curves provided by external markets.

Despite these aspects of the current Alberta arrangements, at least the SC and PA are both within the same organization so they can cooperate and share information to at least some extent; indeed, the process is integrated enough that the term "Pool" is often used to refer to the SC/PA combination with little concern about which entity does what. The principle that real-time operations and pricing should be integrated suggests that the existing integration of physical operations and market pricing in Alberta should be strengthened, not weakened.

3.1.2 Relationships Between the TA and the SC

Alberta began its electricity restructuring with a system in which different public and private entities owned different parts of the transmission grid. So Alberta created a Transmission Administrator (TA) to integrate certain tariff-setting, planning and operational functions for the entire transmission system.[26]

The Alberta TA has both planning and operational responsibilities. It has no role in real-time operations other than providing information, guidelines and R&AS supply functions to the SC in advance. But the TA coordinates grid outages with grid owners and generators, sets the security standards used by the SC in managing operations, provides the SC with dispatch guidelines intended to reduce losses and with information on grid status for the upcoming week, and procures R&AS in a private exchange. It plays a major role in system planning and investment decisions, not only for the grid but – through its subsidies to get generators to locate where it will reduce congestion – for generation as well. The TA has financial incentives to do these things in a way that reduces the cost of losses and congestion.

As discussed in section 2 above, there is no perfect division of responsibilities between the grid and system operations but in general responsibility for real-time operations or their effects should not be divided. Making the TA responsible for the costs of losses and congestion when the TA does not control physical operations violates this principle.

Having the TA responsible for setting the security standards used by the SC in real time is also problematic as long as the TA has financial incentives to minimize the costs of losses and congestion. Security standards have a strong impact on congestion costs, so the entity that sets security standards has a direct conflict of interest if its income depends on congestion costs. Setting security standards involves trade-offs between system costs and system reliability that must ultimately be made in some group decision process. In practice, the North American Reliability Council (NERC) and its subunits (WSCC for Alberta)

[26] In other jurisdictions where this same situation existed, such as Spain, Australia, California, PJM, New York and New England, most operational and some planning functions for the grid have been assigned to the ISO that is responsible for system operations.

establish most of these standards, so Alberta's representative to the WSCC is the appropriate entity to set security standards in Alberta – but should not also have financial incentives to reduce congestion costs.

Having the TA responsible for procuring reserves and ancillary services that are dispatched by the SC is also inappropriate or at least awkward and potentially inefficient. This general issue is discussed in the next subsection.

3.1.3 Procurement of Reserves and Ancillary Services

Alberta currently uses a complex process to procure reserves and ancillary services (R&AS). The TA buys R&AS from generators through a private exchange – Watt-Ex – with the typical contract involving a fixed payment by the TA and a price for each unit of the service actually dispatched by the SC; the dispatch price is usually indexed to the energy prices from the RTM. The TA forwards these (and perhaps other) supply curves to the SC, and the SC uses these supply curves to determine which generators (and loads, if relevant) will provide R&AS in real time.

The general principle that responsibility should follow control suggests that the TA should not be in the middle of the R&AS procurement process, just as it should not be responsible for the costs of losses and congestion. But a more fundamental problem with the current R&AS procurement process in Alberta is the separation of R&AS procurement from real-time operations and energy pricing. This separation requires market participants to predict/guess energy market outcomes when they submit R&AS offers to the Watt-Ex market, and then limits the ability of the RTM/SC to find the most efficient combination of energy and R&AS for each generator in real time. The interactions between energy and R&AS are so strong and complex that, as a general rule, energy and R&AS should be procured and priced in a single, integrated process, i.e., as part of the ISO's integrated system control/spot pricing/congestion management process.

In a spot market that integrates R&AS with energy, each generator submits to the ISO a supply function indicating the prices at which it is prepared to supply different amounts of energy and R&AS, including the technical constraints on its ability to trade off energy for R&AS and any incremental payments it wants (positive or negative, and usually in addition to the opportunity costs of not selling energy) if it supplies R&AS instead of energy. The ISO then uses this information to find a joint energy/R&AS dispatch that minimizes the total as-bid cost of meeting load within system constraints and determines the implied prices for energy and all R&AS simultaneously. Nobody has to submit a R&AS supply curve based on guesses about the outcome of the energy market, or limit its flexibility in the energy market because it has committed to supply the wrong amounts of R&AS, and yet each (competitive) generator makes at least as much money, and probably more, than it would have made in a decentralized, guessing process.

ISOs around the world – e.g., in New York, Australia, New Zealand, PJM, New England – now use and/or are developing integrated energy/R&AS markets of the type outlined above. Such a process is an extension of the concept that the ISO should operate a real-time energy market, and as such is strongly opposed by those who say that ISO-operated markets compete unfairly with private markets. But assuring the procurement of adequate supplies of reliable R&AS is inherently a monopoly function that should be done as efficiently as possible, which usually means in an ISO-operated, simultaneous energy, congestion and R&AS market.

Some markets allow the market participants responsible for paying for R&AS – usually the load-serving entities (LSEs) – to provide "their own" R&AS, on the grounds that this reduces the ISO's alleged monopsony power and allows each LSE to find the least-cost way to meet "its" R&AS needs. But an ISO buying R&AS is not exercising monopsony power unless it sets R&AS requirements below efficient levels in order to depress prices,[27] which is seldom a problem. Indeed, most ISO's are criticized for being overly cautious by setting R&AS requirements too high and increasing R&AS prices above efficient levels, particularly at critical times.[28]

R&AS are inherently public goods that are needed for system purposes, not to support any particular LSE or transaction, so allowing each LSE to provide "its own" R&AS is an artificial process that is unlikely to stimulate useful innovation or cost savings. Before each LSE can buy "its" R&AS, the ISO must define the amount, mix, quality and location of the R&AS that each LSE must buy and the amount that each R&AS supplier – including anybody proposing a new way to provide R&AS – can sell. Then, because individual buyers and sellers of R&AS have no reason to care whether "their" specific R&AS actually do anything for the system, the ISO must enforce the R&AS requirement on each LSE and R&AS supplier. Letting the ISO buy the required R&AS directly and allocate the resulting costs to LSEs does not increase the ISO's role, but can make it much easier and less costly for the ISO to do its inherently monopoly job.

The principle that the ISO should not operate any markets was one of the pillars of the initial California market design, and led to separation of the reserve markets from energy markets and from ISO operations. The resulting inefficiencies and gaming drove reserve prices to very high levels even before problems appeared in the energy market, forcing the ISO to adopt a "rational buyer" approach – over strong opposition from proponents of the market separation philosophy. Although it has not yet been decided how R&AS will be treated in the integrated California market now being developed, most stakeholders appear to want integrated procurement of energy and R&AS by the ISO.

Separate procurement of R&AS has not created the kind of dramatic problems in Alberta that it caused in California, but the general principles outlined above suggest that this process is

---

27 An ISO could also exercise monopsony power by price-discriminating rather than paying all sellers the same market-clearing price. This need not create inefficiencies, but in the short run could transfer wealth from R&AS suppliers to consumers and hence is sometimes proposed by consumer advocates.

28 An ISO that buys less R&AS when their prices are higher, in effect accepting more system risk in exchange for lower costs, may be doing (depending on the details) just what any rational, perfectly competitive buyer would do.

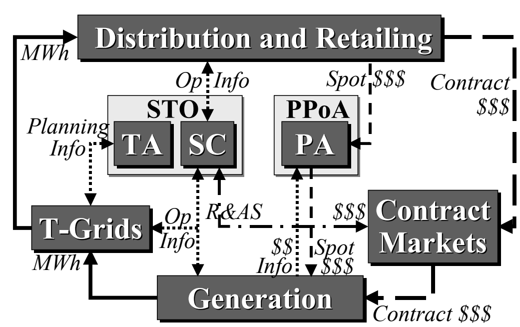
adding to electricity costs in Alberta even if these costs are not glaring or easy to quantify. Any redesign of the Alberta market should consider removing R&AS procurement from the TA and placing it in the organization responsible for system control. Ultimately, R&AS should be procured as part of an integrated system control/spot pricing/congestion management process operated by the SC/PA.

3.2 The Initially-Preferred "Triumvirate" Structure

The LE Briefing Note preferred a "triumvirate" structure for the Alberta electricity market, subject to further discussion with Alberta stakeholders. Although the Final Recommendation proposes the different structure discussed in section 3.3 below, on operational and pricing matters the final recommendation and the triumvirate structure are functionally much the same. Given these similarities and the fact that the LE Briefing Note provides some additional details, it is useful to discuss the triumvirate structure briefly here.

Figure 5 illustrates the operational and pricing legs of the three-legged triumvirate structure favored in the LE Briefing Note. The first leg is a Standing Transmission Organization (STO) that is "managed by a for-profit Transmission Administrator [TA] with responsibility for transmission planning, operation, and system control;" the STO contains, and the TA operates, a SC that combines the operational responsibilities now split between the SC and the TA. [LE Briefing Note, p. 1] The second leg is the Power Pool of Alberta (PPoA) that contracts with a Pool Administrator (PA) to perform "the existing Pool Administration function and [is] focused on operating markets." [LE Briefing Note, p. 1] The third leg of the structure, not shown in Figure 5, is an independent Competitive Electricity Markets Oversight Authority (CEMOA) that would replace the MSA that is now within PPoA.[29]

Figure 5: The "Triumvirate" Structure



The critical characteristic of the triumvirate structure for the purposes here is the virtually complete split between system operations and any markets including the RTM. The STO/TA that includes the SC would be governed by a stakeholder board and regulated by the Alberta Energy and Utilities Board (AEUB), while the PPoA that contracts with the PA to operate the RTM would be governed by a different stakeholder board and regulated by the CEMOA.

The advantages ascribed by LE to this fragmented structure are primarily related to governance. For example, the LE Briefing Note says that the structure would create "three strong, focused organizations which serve as 'champions' for their respective areas of responsibility" [LE Briefing Note, p. 1] to "provide Alberta with a set of focused institutions with clearly defined missions, boards which allow for stakeholder involvement without risking capture by parochial initiatives, and appropriate incentives for performance." [LE

[29] The Balancing Pool would be restructured and put into the Department of Energy.

Briefing Note, p. 5] But beyond saying that the STO controls real-time operations and the PPoA manages the RTM, the LE Briefing Note does not define the "clearly defined missions" or how they would be performed, and does not describe what "incentives for performance" might be "appropriate."

The LE Briefing Note does not consider the difficulties the separate SC and PA would have cooperating or sharing information in order to maintain efficient real-time operations and prices, presumably because LE does not regard such cooperation or information sharing as important or even desirable. Indeed, the basic but implicit assumption underlying the LE papers is that real-time system control and real-time pricing are two different, separable processes, not two inseparable parts of an integrated system control/spot pricing/congestion management process as discussed in section 2 above, so the SC and PA need not and even should not cooperate or share information.

LE is quite explicit about its assumption that the SC can and should operate the system without market data. For example: "Because we envision the TA operating the SC in response to a merit order provided by an external market institution, [the TA/SC] would not necessarily even need to have access to price data" – even if congestion management were based on LMP. [LE Briefing Note, p. 43, including footnote 23] As another example: Under proposals that LE says are now being considered by PPoA and that LE implicitly endorses, the SC's "dispatchers would be provided with the generation stations and dispatch volumes, rather than price information, given that the later [*sic*] is not strictly speaking essential for the SC to do its job once the merit order has been formulated."[30] [LE PA paper, p. 24]

LE's assumption that real-time trading and pricing can and should be separate from the SC's real-time functions is implicit in the LE recommendation (discussed in section 3.3.2 below) that there eventually be multiple, competing RTMs operated by "external market institutions." LE accepts that "[t]here may be instances where the STO, acting through the TA, will also need to set up markets … [such as] markets for firm transmission rights … [but we] would expect the TA in this instance to hold a competitive process for market operators." [LE Briefing Note, p. 2] This at least strongly suggests that, in LE's view, markets can determine efficient prices, including prices for real-time transmission congestion, without being integrated with real-time system operations.

The assumptions that the SC – or, more generally, any ISO – can manage real-time imbalances and congestion efficiently without using any prices or markets, and that efficient real-time prices for energy and congestion can be determined by one or several exchanges external to the SC/ISO, are fundamentally inconsistent with the theory and practice of competitive electricity markets outlined in sections 1.5 and 2 above. An electricity market

[30] LE is incorrect about this – as long as costs matter and the Alberta grid has some loops. Real-time congestion is managed by "redispatching" generators – i.e., by increasing the output of some generators while decreasing the output of others. In any but the simplest "radial" situations, many different redispatches, each with its own costs, can relieve the same congestion. Without knowing the costs/offer prices of each generator the SC cannot redispatch efficiently except by blind luck.

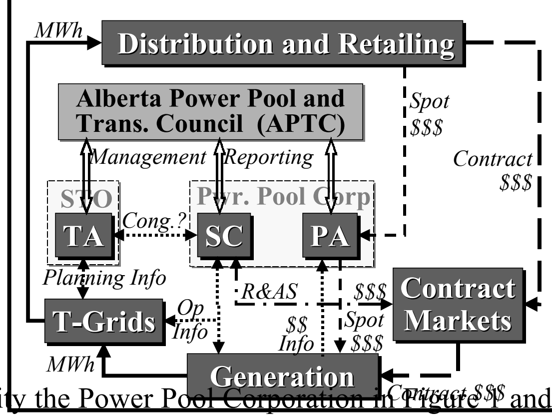
designed on these assumptions is unlikely to perform well even if the entities within it could have good focus, clearly defined missions and appropriate performance incentives – which is unlikely to be the case, given that these entities will have difficult or impossible jobs to do.

3.3 THE RECOMMENDED STRUCTURE

Figure 6 illustrates the structure and management reporting arrangements proposed in the Final Recommendation. This structure appears less fragmented than the triumvirate structure favored earlier by LE and illustrated in Figure 5, because the SC and the PA are now in the same organization – called here the "Power Pool Corporation" or just "Corporation"[31] – and both the STO and the Power Pool Corporation are overseen by a single Alberta Power Pool and Transmission Council (APTC).[32] But underlying this structural integration is even more functional fragmentation than in the triumvirate structure. Furthermore, as discussed in section 3.6 below, the tension between structural appearance and functional reality creates serious governance, managerial and incentive problems.[33]

3.3.1 THE THREE-WAY FUNCTIONAL SEPARATION

Figure 6: The Final Recommendation



Conceivably, the Power Pool Corporation in the recommended structure could combine its SC and PA functions into the kind of integrated system control/spot pricing/congestion management process recommended here, creating a version of the "ISO Model" discussed in section 3.4 below. But the Final Recommendation proposes managerial

[31] The Final Recommendation calls this statutory entity the Power Pool Corporation in Figure 1 and most of the text, but sometimes calls it the Power Pool of Alberta [e.g., p. 4]. The Final Recommendation sometimes uses the terms "Power Pool" [e.g., p. 7] and even just "Pool" [e.g., p. 4] in contexts where the reference must be to the Power Pool Corporation, but also uses these same terms in contexts where the reference must be to the Pool Administrator [e.g., pp. 25 and 26]. To minimize confusion, this report avoids the terms "Power Pool" and "Pool," using the acronym "PA" to refer to the Pool Administrator and the term "Power Pool Corporation" or "Corporation" to refer to the statutory entity that (nominally) contains both the SC and the PA in the Final Recommendation.

[32] The APTC is shown in Figure 6 even though governing boards are not shown for other structures, because (as discussed in section 3.6 below) the APTC in the recommended structure is not just an oversight board but must play an active management role. Figure 6 does not show the AEUB and CEMOA that regulate the STO and the Power Pool Corporation, respectively.

[33] The STO and the Power Pool Corporation are in the background in Figure 6 because these entities have little role or substance under the proposed governance and management arrangements. Only the TA, the SC and the PA have any operational responsibilities, and these three all apparently – the Final Recommendation is unclear about this, as discussed in section 3.6.2 below – report separately and directly to the APTC.

arrangements and restrictions on cooperation and information sharing that would most likely prevent such integration. In particular, the SC will be only "*nominally* [emphasis added] within the [Power] Pool Corporation but operating at arms length from the Pool Administrator," [p. 35] and will have "dedicated employees, a separate budget, and a code of conduct for its relations with the Pool" [p. 25] that would (probably[34]) be designed explicitly to prevent development of an integrated system control/spot pricing/congestion management process.

The TA in the recommended structure is to be "responsible for … congestion management" [p. 30] and for "taking measures to appropriately manage congestion," [p. 5] even though the TA has no operational interactions with the SC or PA. The STO/TA and Power Pool Corporation will share no staff or resources, and will apparently be prevented from sharing information except that their "executives could periodically hold informal discussions to assure [information] systems compatibility." [pp. 6-7]

This three-way separation of system operations from spot pricing from congestion management conflicts directly with the theory and practice of electricity markets outlined in sections 1.5 and 2 above. Even if the TA's responsibility for congestion management is only to develop a congestion management policy that will be implemented in real time by the SC/PA, the functional and reporting separation of the SC from the PA makes the recommended structure essentially no different from or better than the triumvirate structure as far as operations and pricing are concerned.

3.3.2 System Operations and Competition Among RTMs

The Final Recommendation further suggests that, in the future, even "real-time" trading and pricing could be managed by multiple, competitive, private exchanges. The Final Recommendation concedes that competition among multiple RTMs is not practical "over the near term," but says that the APTC should periodically review the "monopoly status" of the PA's RTM and end it as soon as practical.[35] [p. 25] The key issue is "whether the transaction costs of setting up the System Controller to deal with multiple market operators are outweighed by the benefits of competition among exchanges." [p. 25]

[34] LE does not define the intent or content of the SC/PA code of conduct in any detail, but the interpretation in the text here is consistent with section 6.3.2 of the PA working paper which states that "an explicit code of conduct [between the SC and PA] would serve to formalize procedures the Pool already has in place" [or is considering] that would prevent the SC from seeing PA price information or playing any role in determining prices. [LE PA paper, p. 24]

[35] The actual statement is that the APTC should consider "contracting out spot market operation," which could be interpreted to mean only that the APTC should consider contracting out some of the functions involved in operating a monopoly system control/spot pricing/congestion management process. But competition to provide contract employees to a monopoly SC/PA process does not seem to be what the Final Recommendation has in mind, given the reference to "competition among exchanges." [p. 25]

LE does not indicate what or how large the "benefits of competition among exchanges" [p. 25] might be, but the quotation in the previous paragraph suggests that the only costs of introducing such competition would be the costs of the additional communication links between the SC and multiple exchange operators. In LE's view, having multiple, competing RTMs would not reduce the efficiency of real-time system operations, or of real-time trading and pricing – a proposition that is quite inconsistent with the theory and practice of competitive electricity markets discussed in sections 1.5 and 2 above.

If the SC does not use a monopoly RTM to manage imbalances and congestion, it must use less efficient non-market processes, and the competing "spot" markets must, by definition, close some time before real-time operations and ignore real-time congestion.[36] Such markets will not be real-time markets at all, but at best very-short-forward markets. Thus, the alternative to a monopoly RTM integrated with an efficient SC is not multiple competitive RTMs operating in parallel with an efficient SC, but an inefficient SC and no RTM at all.

3.3.3 Congestion Management

The Final Recommendation proposes that the TA be "responsible for … congestion management" [p. 30], saying that although "congestion management occurs in real time, designing a policy to deal with congestion is a long term system planning task … [and hence] is more appropriate for the TA to perform than for the System Controller." [p. 31] If this means only that the TA will be[37] responsible for developing a congestion management/pricing policy that will then be implemented by the SC and/or PA it is not necessarily inconsistent with efficient system operations and pricing. But it is by no means apparent that this is all that LE means by the TA being "responsible for … congestion management." [p. 30]

The Final Recommendation says that "[c]ongestion management entails determining whether the TA's objective should be to plan the system in such a way that congestion is eliminated, or to price the resulting congestion so as to affect generators' operational and locational decisions." [p. 30] The first half of this statement suggests that the TA may continue the current policy of socializing congestion costs by paying for transmission expansions and subsidizing generators to locate in critical areas so that there is little congestion to be managed and priced in real time. Leaving congestion unpriced in the real-time market will require the monopoly TA to play an increasingly costly and interventionist role in the

[36] The problem here is fundamental and cannot be solved with faster computers or communication. Loop flows on a complex AC system mean that the feasibility of each point-to-point transaction depends on every other point-to-point transaction, so there is no logical way for one of several exchanges to know whether its transactions are feasible on the grid without simultaneously knowing all transactions in all other exchanges. Nobody has yet demonstrated even a conceptual solution to this problem that does not involve putting all transactions into a single computer model that includes an accurate representation of the entire physical grid and analyzing all transactions and the grid simultaneously. This is inherently a monopoly process.

[37] The TA in the current Alberta structure is responsible for developing a congestion management policy and is reportedly about to propose one.

market, and is unlikely to eliminate real-time congestion at acceptable cost. Although this is what Alberta has done so far, a more market-oriented approach is probably needed for the future.

The second half of the statement quoted in the previous paragraph suggests that real-time congestion might be priced, but says nothing about how or by whom. The only way to (try to) do this without letting the SC operate a real-time market is for the TA to use the physical characteristics of the grid to define transmission rights that can be traded along with energy in multiple forward markets separate from the SC or PA, to determine generation schedules that the SC can implement in real time using some unspecified non-market process.

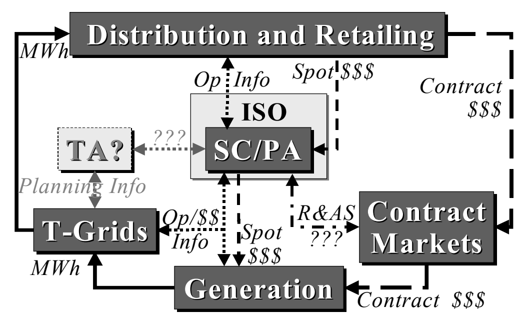
The latest and most sophisticated attempt to find some way to manage and price congestion without a RTM operated by an ISO is based on flowgate rights (FGRs). Some emerging RTOs in the United States have tried to develop a workable flowgate market but have been unable to do so. When a pure FGR market proved unworkable, FGR proponents tried to develop a hybrid in which forward trading would be based on FGRs and real-time operations would be managed and priced in an ISO-operated system control/spot pricing/congestion management process with LMP. Most emerging RTOs – including RTO West[38] – have given up even on this use of FGRs.

The most logical and workable way to manage real-time congestion is to recognize that congestion and system balancing (and reserves and ancillary services) are inseparable parts of a single economic problem, and that the best way to solve such a problem is with a market that determines physical operations and the associated prices simultaneously. This solution will be difficult or impossible if the structural and managerial proposals in the Final Recommendation are adopted.

[38] See "Restructuring Today," January 24, 2002.

3.4 AN "ALBERTA ISO" STRUCTURE

Figure 7: An Alberta ISO Structure



The LE Briefing Note outlines a "centralization of functions" or "Alberta ISO" structure, and the Final Recommendation mentions this option in passing. According to the Final Recommendation, the principal characteristic of an ISO is that it would "combine the Pool [presumably meaning here both the SC and the PA] and TA into a single entity." [p. 36] LE does not discuss what an ISO would do, how it would do it or what the possible advantages and disadvantages might be. Instead, after acknowledging that "some have advocated the creation of an Alberta ISO," [p. 36] the Final Recommendation dismisses the idea with the observations that "there is by no means a consensus on this issue" in Alberta and "there is no such thing as a single 'ISO Model'" in the United States or elsewhere. [p. 36]

The fact that there are many variations on the ISO theme is no reason to dismiss the theme without consideration and recommend something fundamentally different, particularly when so many successful operating electricity markets around the world, as well as the standard market model now emerging in the United States, all use the same basic variation on the ISO theme. The essential characteristic of the increasingly-dominant ISO model has little to do with governance or incentive issues – except that the ISO must be independent of any market participants – and everything to do with system operations and pricing. In particular, the most successful operating electricity markets in the world and the emerging standard market model in the United States are all based on an integrated system control/spot pricing/congestion management process – the type of process that would be very difficult or impossible in the structure proposed for Alberta in the Final Recommendation.

Figure 7 uses the functional entities familiar in Alberta to illustrate an ISO structure designed to facilitate an integrated system control/spot pricing/congestion management process. In this structure, all real-time operational and pricing functions are carried out within a single ISO that is governed by a single independent board and regulated by appropriate entities (not shown in Figure 7). The operational responsibilities now split between the TA and SC in Alberta are combined within the SC, and the SC either operates a RTM (and perhaps hour-ahead and/or day-ahead markets as well) itself or cooperates closely with a PA division of the ISO that does so.

The critical operational features of the ISO model are that the SC makes real-time control decisions based on RTM offers, while RTM prices reflect the outcome of real-time operations. This organizational integration of inherently inseparable functions simplifies as much as it can be the difficult job of governing and managing infrastructure monopolies.

The procurement of R&AS in an ISO (or other) market should be an integral part of the SC/PA process; as discussed in section 3.1.3 above, letting LSEs buy "their own" R&AS, or including external contract markets in the process, adds little except transaction costs and dilution of responsibility, although it can be done if desired. Transmission planning is – as it will always be in any system – a multi-party cooperative/consultative/adversarial/regulated process; either the ISO or a separate TA (presumably under contract to the ISO) could manage this process.

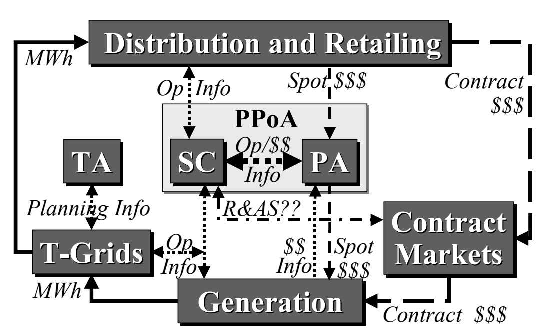
The Final Recommendation says that "in some ways" the structure recommended there "does exactly" what an ISO would do, because the APTC in the recommended structure serves "as a bridge between two entities [i.e., the STO/TA and the Power Pool Corporation] which are intended to focus on core competencies related to their underlying mission." [p. 36] But providing a "bridge" over which the STO/TA can send messages to the Power Pool Corporation through an elected committee, or even allowing the executives of the STO/TA and Power Pool Corporation to consult "informally" on information system matters [pp. 6-7], does not do even approximately what a well-designed ISO does: operate an integrated system control/spot pricing/congestion management process. Conceivably the Final Recommendation could be modified to allow the SC and PA to cooperate within the Power Pool Corporation to develop such an integrated process, but the now-proposed managerial arrangements and restrictions on cooperation and information sharing effectively prevent this.

Creation of an Alberta ISO with the structural features illustrated in Figure 7 would not require immediate implementation of the kind of integrated system control/spot pricing/congestion management process recommended here. But once an ISO is created, movement toward such a system would be relatively easy. Over time, the system would naturally evolve toward such an integrated system, including the use of LMP and FTRs, as this becomes the standard model elsewhere in North America.

3.5 THE "INCREMENTAL CHANGE" ALTERNATIVE

Figure 8 illustrates the incremental change alternative outlined by LE as a fallback position if more fundamental change is not possible. This alternative would change the current structure primarily by removing the BP and MSA (not shown in Figure 8) from PPoA and transferring most of the TA's current operational responsibilities to the SC within PPoA. LE does not say whether the process for procuring R&AS should be changed or whether the TA should somehow be responsible for congestion management as it is in the recommended structure.

Figure 8: "Incremental Change"



The recommendations to remove the BP and MSA from PPoA, and to move most of the TA's operational responsibilities into the SC, are appropriate and should be accepted even if no bigger changes are made. In fact, if there are no restrictions on cooperation or integration between the SC and the RTM, and the TA clearly has no responsibility for R&AS procurement or real-time losses and congestion, no further changes in the basic Alberta structure would be essential at this time, because any desired changes in the system control and pricing processes could be made by PPoA as internal matters. If a separate, contractual TA is maintained, it could be largely a planning and tariff-setting entity operating under contract to PPoA.

If the incremental changes suggested above are made in the existing Alberta market structure, additional incremental changes could be made later to allow the SC and PA to cooperate more closely until an integrated system control/spot pricing/congestion management process evolved. Simultaneous optimisation/procurement of energy and R&AS, and LMP and FTRs, could be introduced when these are desired in Alberta. Ultimately, an ISO-like process could evolve, whatever the various entities in the structure might then be called.

3.6 Governance, Management and Incentives

The proposals in the Final Recommendation are based on asserted governance, management and incentive benefits of the recommended structure, with little consideration of the operational or pricing implications. This section discusses some governance, management and incentive issues raised by the recommended structure and questions whether the Final Recommendations would have even the advantages claimed for it in these areas.

3.6.1 Board Selection and Responsibilities

The LE papers recommend buffered, stakeholder elected boards for all the entities that would operate the systems and markets in the alternative structures, including the APTC in the recommended structure. By this, LE means that an executive search firm will define a slate of candidates meeting specified professional criteria, and then stakeholders will elect the board voting by class, i.e., each class of stakeholder will have a specified percentage of the total votes independent of how many voters there are in that class. Board members will be independent of any stakeholders and will have a fiduciary duty to the entities they oversee, not to stakeholders.

There is no perfect way to choose the governing board for any public-interest organization, and a buffered, stakeholder voting process is as good as any and better than most. Boards composed of stakeholder representatives tend to degenerate into interest-group politics or to be paralysed by rigid decision rules designed to prevent dominance by any stakeholder group, and politically appointed boards tend to be influenced by political factors that are larger – or smaller, depending on how one looks at it – than the interests of "the market." But buffered, stakeholder-elected boards have problems of their own, often including limited direct, current knowledge of the industry and limited personal interest in and commitment to the entities they oversee.

The problem of non-expert boards is usually managed by creating expert committees to advise the board, particularly on proposed changes in technical operating or market rules that will usually benefit some market participants at the expense of others. But such committees are, by necessity, usually composed of industry experts associated with interested parties, and hence require defined membership and voting rules that can reintroduce the problems of interest-group politics and paralysis that the buffered board was intended to eliminate. These problems may be less serious at this lower level, but only if the board is able to walk the fine line between rubber-stamping technical committee recommendations it does not understand and second-guessing its committees because it doubts the fairness of the process.

A more fundamental problem in structuring the board of an electricity infrastructure monopoly is deciding just what and whose interests the board is supposed to protect and advance, given that such a monopoly is not a normal commercial business but is providing an essential and complex public service. An earlier LE working paper proposed that STO board members have a fiduciary duty to "promote open access and system reliability," [TA&SC report, p. 42] making the board primarily a guardian of the public interest. But the Final Recommendation says that APTC members are to have a "fiduciary duty towards the corporations which they oversee," [p. 7] making the board more like a traditional corporate board. This fundamental change in recommended board responsibility illustrates but does not resolve the conflict between the interests of the organizations and the interests of the public.

The board of any electricity infrastructure monopoly must make many decisions that involve trade-offs between the interests of the organization itself and the broader interests of the market and the public. For example, it must decide to what extent the organization will be financially liable to individual market participants for the outcome of its actions, approve trading fees and tariffs, and accept or reject proposed changes in market rules that may shift costs and risks between market participants and the organization. Board decisions on such matters may be guided by founding legislation and may ultimately be reviewed and potentially reversed by regulators or even the government, but such constraints on and oversight of the overseers cannot be very detailed or limiting without destroying the independence and effectiveness of the organization itself. Given the public policy responsibilities of these infrastructure monopolies, their boards cannot focus only on advancing the interests of the monopolies themselves but must also consider the broader interests of the market and the public; if this were not the case, there would be no reason to have the boards elected by stakeholders.

The conflict between organizational and public interests is inherent in the nature of an electricity infrastructure monopoly and complicates the job of the governing board of any such monopoly, including an ISO of the type recommended here. But this conflict can be reduced and managed by assuring that each of the infrastructure monopolies has a well-defined job to do that is largely within its own control, so that its oversight board can focus on setting objectives and incentives that will advance the public interest. Conversely, dividing a technically complex, inherently integrated process among several different organizations requires the oversight board(s) to devote so much time and energy to managerial matters, with such unsatisfactory results, that the interests both of the organizations and the public suffer. The implications of the Final Recommendation in this regard are discussed in the next subsection.

3.6.2 STRUCTURE AND MANAGEMENT OF THE FUNCTIONAL ENTITIES

The Final Recommendation proposes creating the STO as "an identified counterparty to the TA contract," [p. 31] even though the APTC is "effectively … the counterparty" to the TA contract [p. 25] and the TA "ultimately reports" to the APTC. [p. 30] This legal fiction is necessary because the TA is to be a contracted entity and the APTC is supposedly a governing body that cannot or should not enter into contracts itself. The STO has little or no staff of its own and no operating responsibilities, and is "run" or "managed by" [p. 5] the TA it supposedly manages under contract. The STO is said to be useful because it can "step into the TA's shoes in the event of a transition"[p. 31] from one TA contractor to another and can "also serve as a vehicle for limiting liability associated with the transmission sector,"[39] [p. 31, footnote 28] but basically the STO is an empty statutory entity created to hold the TA's contract.

The Final Recommendation is unclear about the structure and management of the Power Pool Corporation and of the PA and the SC that, according to the organization chart [Figure 1, p. 4], are within it.[40] However, a consistent message is that (as discussed in section 3.3 above) the SC and PA are to be two functionally separate entities that report separately and directly to the APTC. It is unclear whether the Power Pool Corporation has any real function – perhaps serving as the PA itself – or is a passive counterparty to contracts with the PA and SC, much as the STO is a passive counterparty to the TA contract.

Thus, the Final Recommendation proposes that the CEOs of the TA, the PA and the SC all report separately and directly to the APTC. Presumably the STO and Power Pool Corporation, as "two entities organized by statute to operate similar to private companies created under the Alberta Business Corporations Act." [p. 4] will also have CEOs that report to the APTC, for a total of five CEOs reporting directly to the APTC. But even if the two statutory entities are ignored on the grounds that they have little to do, the APTC has three functional entities and CEOs reporting directly to it, violating the basic management principle that an oversight board should oversee only one organization/CEO.

In effect, the Final Recommendation makes the APTC an executive committee, and its chair the CEO, of a holding company with three functional subsidiaries – as well as a body with significant regulatory and public policy responsibilities. Combined CEO/board chairs are

[39] The limitation and diffusion of liability inherent in this arrangement are not necessarily advantages, particularly when the principal argument for the recommended structure is that it creates focused entities with clear performance incentives and accountability.

[40] For example, the Final Recommendation states that the APTC will design performance incentives for "the management of the Power Pool Corporation" [p. 32] and that the Power Pool Corporation will "define incentive structures for" the PA and SC [Table 1, p. 4], suggesting a traditional, hierarchical management arrangement. Elsewhere, however, LE "envision[s] the Power Pool [Corporation? Administrator?] and the System Controller having separate chief executives, both of which would report directly to the APTC" [p. 25], and the APTC "designing incentive structures … for … the Pool Administrator," with no mention of the Power Pool Corporation or the SC, [p. 8], suggesting a very different structure.

common, although they have the significant disadvantage that they provide no independent oversight of the CEO/board chair. But such a structure requires a strong CEO/board chair with its own professional staff and the ability to make executive decisions, not a part-time chair elected by stakeholders (or perhaps by the board itself) to preside over a stakeholder-elected committee, buffered or not. Furthermore, the APTC will not be a normal holding company that can provide some common overhead services such as finance and then give each of its subsidiaries incentives to maximize its own profits as the best way to maximize the total profits of the group, because the APTC's subsidiaries must together perform the technically complex, highly integrated function of managing and pricing the real-time operations of an electricity system.

The APTC proposed in the Final Recommendation must divide the complex, integrated dispatch/spot pricing/congestion management process into three separate processes that can be managed by three separate entities that are constrained in their ability to cooperate and share information with one another. The APTC must then define separate incentive arrangements and codes of conduct designed to get each of its subsidiaries to perform its designated functions well without cooperating or sharing information with the others more than allowed. The analysis of and experience with electricity systems outlined in sections 1.5 and 2 above suggest that it will be difficult or impossible for the APTC to do all of this in a way that maintains reasonably efficient system operations and pricing.

In contrast to the job created for the APTC by the Final Recommendation, the job faced by the governing board of a well-designed ISO is relatively manageable – albeit still far from easy. The ISO board oversees a single organization/CEO that has a relatively well-defined and feasible job to do: operate an integrated real-time (and perhaps day-ahead and/or hour-ahead) system control/spot trading/congestion management process that results in efficient real-time operations and produces real-time market prices that reflect real-time reality. If there are problems with the process, the board knows whom to call to account. The board can, to some extent, define performance measures for the system as a whole and use these to reward or penalize ISO management; as discussed in the next subsection, this is far from easy, but is easier for an ISO operating an inherently integrated process than for the separate TA, PA and SC that must try to operate pieces of this process in the Final Recommendation. The ISO's governing board can then focus most of its time and energy on its public policy responsibilities.

3.6.3 Performance Incentives

The Final Recommendation does not explain how the APTC will manage the multiple entities under its oversight, beyond saying that it will define incentive arrangements to induce "good" performance by these entities. But it is very difficult to define effective performance incentives even for a monopoly that is responsible for all parts of an integrated process that produces a measurable product; for example, performance-based regulation of integrated electricity monopolies has had at best limited success. It is much harder to define incentive arrangements for several entities, each of whom is trying to one part of an inherently integrated job.

Once most of a monopoly's functions have been clearly defined and most of its assets are in place, it may be possible to write an incentive formula that will reward efficient performance of those functions with those assets over the short term. But appropriate performance incentives cannot be defined, or even presumed to exist, for an entity before it is known in some detail what that entity is supposed to do and how it might actually do it. And experience demonstrates that even the best of incentive formulas will have to be renegotiated frequently as conditions change.

The difficulties of defining effective performance incentives are compounded when an inherently integrated infrastructure function is divided among several entities. For example, it is problematic to base incentives on the costs of losses and congestion when one entity owns and/or operates the grid while another entity controls dispatch, because losses and congestion costs are determined by the interaction of grid conditions and the dispatch. As inherently integrated functions are divided among more entities, it becomes more difficult to define and measure the performance of each of these entities, and more likely that one entity can increase any measure of its own performance by shifting costs to others, which is more likely to increase than to decrease total costs.

The LE papers themselves illustrate the difficulty of defining useful performance incentives. The working papers say that past performance incentives in Alberta have been inappropriate or ineffective because of general regulatory factors (e.g., fear of cost disallowances), incentive formulas that are based on unquantifiable results or routine activities (e.g., providing technical support, participating in processes), or formulas that are based on quantifiable results that are not really under the entity's control (e.g., making the TA responsible for losses and congestion). But LE does not explain how the structure it recommends will make it any easier to design better performance incentives.[41] In fact, by dividing the integrated system control/spot trading/congestion management process among three different entities that are constrained in their ability to cooperate or share information, the LE recommendations would make the inherently difficult job of defining performance incentives even harder than it need be and harder than it would be in a well-defined ISO structure.

4. CONCLUSIONS

Any electricity system requires a centralized system control function. Monopoly utilities generally perform this function well, but in a way that is inconsistent with competition because it is not a market. The principal objective and challenge in creating a competitive electricity market is to design market-based system control and pricing arrangements that reflect operational reality, both to maintain efficient short run operations and – more

[41] It is significant that LE provides only one example of a possible performance incentive: letting up to 10 percent of the TA's management fee be determined by the results of a customer satisfaction survey. [p. 38] Rewarding a monopoly based on such a qualitative, subjective and easily manipulated measure of performance may or may not be a good idea, but it is not likely to stimulate superior performance on complex technical tasks.

importantly – to internalise all significant costs so that market prices will give competitive generators and traders the right signals regarding longer-term actions including investment.

The theory of and experience with competitive electricity markets demonstrate that the key to efficient short-run system operations and market pricing is an integrated system control/spot pricing/congestion management process that manages and prices real-time operations simultaneously. Conversely, trying to divorce physical operations from markets forces the system controller to use inefficient and disruptive non-market mechanisms to manage imbalances and congestion and results in markets that cannot accurately price physical reality. Thus, alternative structures should be evaluated in terms of their abilities to facilitate an integrated system control/spot pricing/congestion management process.

LE's Final Recommendation for the Alberta Electricity Structure Review proposes that real-time system control, spot pricing and congestion management be divided among three different entities. This structure is advocated by LE largely on governance and incentive grounds, with little consideration of how real-time operations would be managed and priced. Although the three recommended entities could conceivably develop an integrated system control/spot pricing/congestion management process if they were allowed to do so, the Final Recommendation proposes managerial arrangements that would make it difficult or impossible to develop such an integrated process. Furthermore, the recommended separation of responsibilities is likely to make it harder, not easier, to develop effective governance, managerial and incentive arrangements.

The analysis in this report concludes that a structure based on an independent system operator (ISO) is the most consistent with the theory of and experience with electricity markets, including recent developments in the United States, and that such a structure would be the best for Alberta. Although there are many detailed variations on the ISO theme, the basic concept is to combine the current operational functions of the Transmission Administrator (TA), System Controller (SC) and Pool Administrator (PA) in a single organization. Combining inherently integrated functions in this way would simplify governance, management and regulation, and would facilitate development of an integrated system control/spot pricing/congestion management process, including locational marginal pricing (LMP) and financial transmission rights (FTRs) if and when Alberta decides to use these. Longer-term planning, tariff setting and policy making could be assigned to a separate TA if desired.

The "minimum incremental change" option considered by LE would maintain and – by moving to the SC some responsibilities now in the TA – even improve the current more-or-less integrated SC/PA process within the Power Pool of Alberta (PPoA). The option would allow development over time of a more fully integrated and efficient system control/pricing process, including joint optimisation and pricing of energy, reserves and ancillary services and the use of LMP and FTRs. Given the difficulty of making large changes to complex structures and institutions, this might be the best alternative for Alberta at this time.