FINAL REPORT

Transmission Must Run

Submitted to

Market Surveillance Administrator: Alberta, Canada

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ABBREVIATIONS

ADOE	Alberta Department of Energy
AESO	Alberta Electric System Operator
AEUB	Alberta Energy and Utilities Board
AIES	Alberta Interconnected Electricity System
COS	Cost of service
EAL	ESBI Alberta Ltd
FERC	Federal Energy Regulatory Commission
IBOC	Invitation to Bid on Credits
ISO	Independent System Operator
LBC-SO	Locational Based Credits – Standing Offer
MSA	Market Surveillance Administrator
OPPs	Operating Policies and Procedures
RFP	Request for proposals
RAS	Remedial Action Schemes
RMR	Reliability must run
SERP	System Expansion Related Pricing
SSS	System support services
TA	Transmission Administrator
TMR	Transmission must run

1. OVERVIEW

The Market Surveillance Administrator of Alberta (MSA) has engaged Charles River Associates (Asia Pacific) Pty Ltd (CRA) to assist the MSA in developing its position in relation to how transmission must run (TMR) services arrangements are delivered and administered in Alberta.

1.1. BACKGROUND

The MSA is conducting a formal investigation into the competitiveness of the arrangements for TMR service in Alberta. The investigation was prompted by the MSA's observation that market participants have found it necessary to refer to regulatory authorities a number of times in a short period seeking changes to TMR arrangements, and a concern that the TMR market may not be conducted in a manner that is consistent with *promotion of a fair, efficient, and openly competitive* market as required by Electric Utilities Act 1996, 2003 (EU Act).

TMR is procured by the body appointed as the Independent System Operator (ISO) under the EU Act. The current ISO operates under the trade name Alberta Electric System Operator (AESO) and took over this function from ESBI Alberta Ltd (EAL) in 2002 who, at that time, filled the role entitled Transmission Administrator (TA). [1]

TMR refers to a general class of network support services provided by operating plant or equipment in a manner that allows the ISO to ensure loading on the transmission network remains within safe limits. TMR services have been acquired from generators under a range of different schemes over the past six years, in particular the Invitation to Bid on Credits (IBOC) and Location Based Credits–Standing Offer (LBC-SO) schemes.

Where they have identified a need for TMR services the ISO/TA have generally been able to enter into a series of commercial agreements for their provision, although there are a number of important exceptions. In particular, negotiations between the AESO and ATCO Power Canada Ltd. (ATCO Power) in relation to services in the Rainbow Lake area have been long-running and have now reached the stage of a dispute that has given rise to an application by the AESO to amend the transmission Tariff.

1 As there have been a number of organisations and names for similar functions over a period of time, for simplicity we shall refer generically to the entity or function responsible for procuring TMR services now as the ISO and the ISO/TA where we are referring to the role over time. Where appropriate, in order to discuss the actions of the particular organisations, we shall the AESO and ESBI Alberta as appropriate, although we recognise that the AESO is the trade name of the current ISO.

During the course of the dispute, the AESO has begun conscripting TMR services under enforced terms and conditions, and fundamental questions have come to light about the rights and responsibilities of market participants and the AESO, as well as wider industry and market governance arrangements.

In parallel, a Transmission Development Policy (Policy) and Transmission Regulation have been issued by the Alberta Department of Energy (ADOE).[2] The Policy shifts the balance away from 'non-wires' based technologies, such as TMR, towards construction of 'wires' with an objective of achieving minimal congestion on the electrical network and thus seeks to improve competition in the energy market. This, for the first time, introduces a criterion based on market outcomes into the transmission planning process in Alberta.[3] Previously network planning aimed to achieve reliability and access criteria in the most cost effective manner. The change represents a profound philosophical shift in the basis for network planning. It will potentially see some transmission investment taking place on the basis of guaranteeing, as a matter of policy, a very high level of physical access to 'in merit' generation, by ensuring that there is effectively no network constraint on the dispatch of such plant.

In other power systems, considerable effort is directed to determining the appropriate balance between generation and network investment on the basis of economic factors, including prices derived from competitive market operation, and it is generally accepted that some level of dispatch constraint might be economic. The mechanism to set this balance in a disaggregated market environment is, however, one of the more difficult and often problematic elements of market design around the world.

By implication, we understand that the Policy is based on the assumption that the cost of any additional network investment will be outweighed by a greater economic benefit within the market for energy by avoiding possible issues arising from locational pricing that have been observed elsewhere. We also note that it is not uncommon for markets in different locations to have unique elements, and policy direction from government is one source of difference. The Policy is a given in our work for the MSA.

1.2. CRA's Terms of Reference

Disagreement over the role of TMR, the procurement process and consequently what constitutes a fair price for TMR services is at the heart of the debate. This sets the context for CRA's review.

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2 The Transmission Policy is being implemented via the Transmission Regulation (AR 174/2004).

3 Hence one of the key conclusions presented in the accompanying Policy Paper is (Page 8): *"6. Transmission must serve and facilitate a competitive wholesale market. Transmission internal to Alberta should be reinforced so that about 95 per cent of expected economic wholesale transactions can be realized without transmission congestion."* Related descriptions also note that this will mean that it is expected that there will be no congestion for mid-merit plant when all transmission is in service.

CRA has then been asked to:

1. Examine the competitiveness of TMR procurement arrangements in the Rainbow Lake area of the Northwestern Region in Alberta;

2. Review and compare TMR arrangements in other jurisdictions;

3. Review existing contracts for ancillary services other than operating reserves;

4. Review the AESO's operating policies and system operation with respect to competitiveness in the Rainbow Lake area; and

5. Propose appropriate amendments to enhance either the competitiveness of current arrangements or, if we find that arrangements cannot reasonably be made competitive, substitute arrangements.

The full Terms of Reference appear in Appendix A.

This report summarises the investigations we have undertaken and our findings. In fulfilling our task we have relied on extensive discussions with the MSA, documentation and research made available to us by the MSA, as well as publicly available material. We have also reviewed a number of contracts for TMR, IBOC and LBC-SO, although we have limited our detailed review to contracts for the Rainbow Lake Area. We have also had access to records of meetings conducted by the MSA with key market participants, and have participated in discussions between the MSA and the AESO. Although we have gone to considerable lengths to ensure that this report represents a comprehensive and accurate discussion of the issues, it must be acknowledged that developing an understanding and subsequent recommendations in relation to the issues raised by the MSA is complicated by a variety of historical factors, including changes in the regulatory and governance arrangements in the Province, and the complexity of the dispute.

1.3. Summary of Findings

1.3.1. Assessment of Current TMR Arrangements

We have found that overall processes and outcomes for TMR, viewed over a number of years, have not been consistent with the *promotion of a fair, efficient and openly competitive* process. We also consider that acquisition procedures should reflect the broad range of supply situations. At times this will allow an open competitive processes, but at other times the need for very specific service at a particular location will reduce the potential for competitive solutions and bounded negotiations, and if necessary, regulatory solutions, will be needed.

Some, but not all, of the underlying circumstances on which our findings are based are being amended as this review is being undertaken.

The Policy and related principles for pricing, for example, are being clarified, but policy in the transition to the new arrangements is less clear. This relates particularly to how fixed costs should be treated in the relevant tariffs, and whether the timing of network upgrades can be coordinated with TMR contracts. The situation is thus very fluid. Our recommendations for the future, introduced in this section and described in detail in the body of the report, note areas where we consider further improvements can be made and address points of detail for changes underway..

A number of factors have contributed to our findings, including:

- The uncertainty created by the changing role and policy for transmission and hence for TMR;
- The multiple roles of the ISO as network planner, rule designer, system operator and TMR contracting agent that force it to act as commercial negotiator, manager of system reliability (including through the issue of Operating Policies and Procedures (OPPs) for dispatch);
- The impact of infrequent and unavoidably non-uniform nature of TMR requirements; and
- The inherent difficulty of reconciling a market design where the energy price does not directly signal the effect of network congestion (as it does in some other markets), with ensuring that participants make efficient locational decisions about investment and the timing of operations, while at the same time ensuring that potential market power across the overall energy and ancillary service markets is, where appropriate, mitigated.

1.3.2. Role of the ISO in an Evolving Market

Our judgement should be viewed against the backdrop of the evolution of the competitive electricity market in the Province and other obligations and expectations of key parties such as the ISO, related to reliability, safety and cost-effectiveness. In this respect we note that Division 1 of the EU Act that sets out the purpose of the Act includes at clause 5 (b):

> *to provide for a competitive power pool so that an efficient market for electricity based on fair and open competition can develop, where all persons wishing to exchange electric energy through the power pool may do so on non-discriminatory terms and may make financial arrangements to manage financial risk associated with the pool price;*

In addition Division 2 of the EU Act includes the following duty for the ISO:

> *The Independent System Operator must exercise its powers and carry out its duties, responsibilities and functions in a timely manner that is fair and responsible to provide for the safe, reliable and economic operation of the interconnected electric system and to promote a fair, efficient and openly competitive market for electricity.*

It is also important to note that although efficiency is a well-defined term in economics, concepts of fairness and openness are general terms. In the context of TMR services, we have taken fairness to relate to the consistent and uniform application of the rules to participants, and open competition to refer to the transparency and opportunity to participate in the provision of the service, and that the resultant price is generally broadly cost reflective.

We also consider that *promotion of a fair, efficient and openly competitive* market requires actively enabling the development of a dynamically efficient market; that is, a market which provides incentives and accountabilities that facilitate investment and innovation, and that enhance economic welfare of each of the stakeholders in the future. A static measure of efficiency is not suggested by the duties of the ISO. This requires that a body such as the ISO be a proactive "market maker" and it can therefore not simultaneously also be an agent for ratepayers seeking minimum price for them.

Over a number of years both the buyer, that is the AESO and ESBI Alberta, and sellers (in general, generation companies) have with some cause had reason to claim lack of fairness of the different pricing arrangements and processes for TMR. The ISO/TA has found itself in a difficult negotiating position with respect to individual participants, but in part this would have been a consequence of the TMR procurement procedures and processes it has adopted. In our view, the scope of the basic level of TMR 'need' has been presented relatively narrowly and has not been well communicated to stakeholders, thus potentially limiting the range of providers to the technology that the AESO and ESBI Alberta presumed would be the winning technology. Regardless of whether their presumptions were correct, it is contrary to the conduct and promotion of an open competitive process for an entity with (quasi) regulatory powers (such as the ISO) to unnecessarily limit the options that it evaluates and the information it provides about its needs for services.

In some ways the current ISO, the AESO, is in a no-win situation. Although the TA was a "for profit" organisation, the present ISO is not, and both entities were required to implement a multi-headed charter for commercial and technical performance. On the other hand, suppliers of TMR are for profit companies and are respondents to a demand for their service determined from time to time by the ISO. The ISO's transmission planning and operational activities determine the need and day-to-day use of TMR, and its commercial department selects how these are procured. Different suppliers appear to have taken different views on the 'intensity' with which they engage the commercial processes – no doubt influenced by the commercial impact for each party and also on their business strategy from time to time. That only one party is currently in dispute in relation to a TMR contract and has not reached a negotiated position with the AESO does not mean it will be the norm for most parties to agree in the future. We consider that, as it would be unusual for parties on either side of a market to be in unanimous agreement about outcomes, disputes about conduct and process are potentially more important than disputes about the operative outcomes in assessing the fairness and openness of procurement arrangements.

As the ISO is in control of the determination of need and the TMR procurement process, any identified problems or suggestions for change will have an appearance of criticism of the ISO. This is unavoidable and we suggest is a fact of life for market operators. In contrast, the commercial providers can be portrayed as simply fulfilling their for-profit-role in the market, and this includes attempting to influence regulatory outcomes to their advantage. Nonetheless we note that Part 1 (6) of the EU Act states:

> *Expectations of market participants*
>
> *Market participants are to conduct themselves in a manner that supports the fair, efficient and openly competitive operation of the market.*

It is not surprising therefore that in the course of our investigation we have observed a general sense of dissatisfaction at different times with the actions of the ISO/TA on the part of some providers of TMR and, conversely, a rejection of the negotiating positions taken by suppliers on the part of the AESO. We would emphasise that it is not our role to resolve the existing disputes or disagreements per se. There are formal processes in place for this, and our role is limited to considering if the outcomes have been consistent with the high level objective of promoting the market in terms of fairness, efficiency and openly competitive processes, and to recommend relevant changes for the future.

Therefore, although we consider that the AESO and ESBI Alberta could in retrospect have managed the TMR process differently and more in line with dynamic efficiency objectives, government authorities and stakeholders might also have acted earlier, more decisively or less aggressively to refine policy, or seek more timely amendments to pricing arrangements. Although TMR outcomes have been unsatisfactory in that there is on-going dispute and an apparent lack of goodwill, we have not identified any particular party that has not acted rationally in the face of the incentives, opportunities and obligations they perceive are created by the overall market design and governance/policy arrangements.

A key issue for this review is whether those incentives and interpretations have been reasonable and 'correct' – and this is to a large degree a matter of policy and is the subject of much of the analysis in this report. We also note that the broad package of arrangements relating to TMR has changed considerably over the last four to five years and is continuing to change thus complicating the analysis.

1.3.3. Options for the Future

In considering recommendations for the future, it is appropriate to learn from the past, but equally important to recognise how the environment is likely to evolve. This is particularly important for dynamic efficiency, as (prospective) changes to structure will affect different players differently, for example a proposed grid expansion may strand assets. Unless regulatory change is implemented in a transparent and planned way that recognises this, the integrity of the regulatory framework including the market design will be placed at risk.

In the light of the Policy issued by the ADOE, which, as noted above, we expect will dramatically reduce (in line with intentions) the potential use of TMR, our recommendations focus on unravelling the multiple roles of the ISO to give greater certainty and transparency, particularly in the balance between the *promotion of fair, efficient and open competition* and the price of TMR sought from negotiation, and restoring lost confidence in the acquisition of TMR. In our view this is necessary for *promotion of fair, efficient and openly competitive* arrangements.

Because of the multiple roles of the ISO we suggest that its adherence to operational processes and rules it promulgates be the subject of systematic monitoring by the MSA.

These recommendations are in addition to the resolution of pricing principles for TMR by the Alberta Energy and Utilities Board (AEUB) as neither is likely to be sufficient alone. In that regard we would also urge that in parallel with decisions about TMR pricing arrangements, statements of principle for the conduct of future negotiations and definitions of need for TMR should be enhanced.

In particular, we consider that the environment for *promotion of fair, efficient and open competition* for TMR will be improved by arrangements that aim to:

- Seek the broadest field of competitors through a needs analysis designed to identify the broadest possible scope of providers and technologies;
- Retain as many possible providers in the process for as long as possible;
- Maximise information to the market about the process and future opportunities;
- Balance the need to comply with relevant boundaries on the terms and conditions for contracts, prudency and commercial bargaining power of all parties; and
- Recognise that, particularly during transition to a stable network planning environment under the new Policy, there may be situations where those boundaries are not viable, and it is not realistic to expect a tariff to contemplate all such situations. Any uncertainty or flexibility in the timing of implementation of the network would add another useful and relevant dimension to contracting for TMR options. Hence arbitration, and as a last resort regulation may be required.

We have included a final regulatory backstop role that has been assigned to the AEUB rather than a separate commercial arbitrator, as it is the AEUB that must approve subsequent tariffs to allow the ISO to recover the costs incurred.

The key elements of our broader recommendations are:

- Implementation of the Policy in relation to, under what, if any, circumstances the ISO should employ TMR, or equivalent non-wires approaches as a substitute for transmission should be clarified;

- The scope of technologies that are explicitly considered as possible sources of TMR should be broadened and should include generators that are outside the market, for instance, standby generators in industrial facilities along with other non generation technologies (including synchronous condensers, demand side management and power factor correction facilities);

- The factors taken into account in the pricing of voluntary and conscripted TMR should recognise that there are differences between cost recovery in a market environment and a fully regulated situation;

- The factors taken into account in the contracts for TMR should recognise that, particularly where there is limited competition, it is desirable that contracts are for a period of time that reflects the planning for the transmission upgrade;

- The role of the ISO in relation to promotion of fair, efficient and open competition vis a vis that of prudency and short-term cost minimisation should be clarified. That is whether the ISO should be an agent of ratepayers or a market maker between buyers and sellers, as it cannot be both;

- The balance of responsibilities between the planning, commercial and operational functions of the ISO should be such that network planning will be based on the principle that reliability standards on the network can be met on a planned basis without recourse to conscription (for defined operating conditions) at all times. Hence, any reliance on TMR would require that appropriate contracts remain in place at all times;

- A consistent and transparent framework for the procurement of any TMR identified as needed should be adopted and this should incorporate, broadly in order, appropriate steps from the following:

  - Regular indications to the market of likely locations and applications where TMR may be sought in the future;

  - Where TMR is to be employed, an Expression of Interest (EOI) process designed to guide the design of the subsequent formal process emphasising the nature of the engineering problem, and seeking potential solutions from as broad a range of technologies and providers as possible;

- Wherever possible (guided by responses to the EOI) an open and fully competitive process as the preferred method of acquisition within any pricing bounds established by relevant authorities from time to time (e.g. the EUB, Regulations) and the ISO Board in relation to prudency;

- Where an open process is not appropriate or a competitive process has failed, bilateral negotiations with as many parties as practicable, within any pricing bounds as established by relevant authorities from time to time (e.g. the AEUB, Regulations) and the ISO board in relation to prudency;

- Arbitration within any pricing bounds established by relevant authorities – but at this stage, excluding limitations established by the ISO Board);

- Advice from the ISO to the AEUB that the acquisition process has been unsuccessful within the bounds that have been applied, and that the TMR need and hence its network planning obligations will not be met. The timing of advice to the AEUB should be a balance between allowing reasonable time to negotiate or for arbitration to be completed and the lead-time for project development. In those circumstances and on a case by case basis, the AEUB should have authority to institute a transitionary measure involving direction to:

  - The ISO, to reissue the tender with amended terms and conditions;

  - A provider (subject to confirmation of legal authority) to enter into a contract on stated terms and conditions – that is a conscripted contract; or

  - The ISO, to reassess its transmission planning intentions and potentially construct network where TMR was proposed to be employed: the timing of network construction to reflect the value of (delay) options as to timing and existing available TMR.

Where any of these steps results in increased costs to the ISO, AEUB endorsement will represent an intention to approve subsequent elements of a tariff submitted by the ISO.

Time may prevent the full application of the process, and the detailed design should impose obligations on all parties to act in a timely fashion.

Finally, we note that the recommendations for improvement to the regime for TMR presented here will require a multi agency response. This is not surprising as the overall market arrangements are set by the interaction of the roles and responsibilities of the Department of Energy, the AEUB and the ISO, and this is very typical of competitive markets internationally. However, it suggests that there will need to be a closely coordinated response to ensure a consistent package of changes to regulatory arrangements and work practices is achieved.

1.4. STRUCTURE OF THE REPORT

In order to assess the operation of the TMR environment we considered three broad perspectives:

- Technical processes, in particular how the previously integrated technical analysis and operations are undertaken in the combined competitive/ regulated world;
- The overarching governance framework, which includes the structure of the industry, roles and responsibilities for the different functions and the objectives of each of the parties; and
- Commercial processes, in particular their design and the exercise of discretion of different parties in the light of the governance obligations imposed on them as well as the more traditional commercial behaviours of parties to bilateral negotiations.

Our analysis of each of these perspectives is presented in the body of this report:

- Section 2 reviews the relevant Alberta market and reform context, and the difficulties that arise in the context of network support services that are neither unambiguously market based, nor clearly fall into the regulated arena;
- Section 3 introduces the technical principles of TMR and reviews procurement processes applied by the AESO for acquiring TMR services;
- Section 4 broadens the analysis to consider wider commercial and governance including issues raised by the Rainbow Lake dispute;
- Section 5 reviews the treatment of TMR and other ancillary services in other markets and jurisdictions; and
- Section 6 presents options for the future treatment of TMR.

The following appendices provide additional supporting information:

- Appendix A sets out CRA's terms of reference in detail;
- Appendix B sets out the relevant statutory framework for this review;
- Appendix C describes the regulatory history in relation to Articles 4 and 24;
- Appendix D summarises historical network pricing arrangements;
- Appendix E provides a review of selected international arrangements; and
- Appendix F introduces the authors of the paper.

2. TMR WITHIN THE ALBERTA MARKET

This section sets out the evolution of TMR and similar network support services in the context of the reform of the Alberta wholesale market for electricity.

2.1. SCOPE AND EVOLUTION OF TMR IN ALBERTA

TMR is a form of ancillary service contracted by the ISO to ensure that load on parts of the network stay within safe limits by providing for the ISO to instruct plant operation at critical times. It is thus a substitute for augmentation of the transmission network. The precise need for TMR services in a particular situation is complex and is a product of characteristics of the power system, assumptions about customer loading levels, the availability of generators for service, and the overall framework for transmission development.

In a centrally planned environment, utility planners would have sought to find the most cost effective means to deliver the required level of reliability. As deemed appropriate, network and non-network facilities would be sited and operated as a portfolio. At times this would have resulted in non-wires based facilities including generation, demand side, reactive plant and fast acting control equipment being employed where they could meet the technical requirements at a lower cost to traditional wires based network solutions. An integral part of a centrally planned regime is that the central planners pass all financial risk that their decisions were not in the end the most cost effective, to ratepayers, including inaccuracies in demand forecasting and differences between actual and forecast costs of construction and operation.

A key feature of reform in the electricity industry is the reallocation of decision-making and risk. As reform has progressed and the Alberta electricity industry has been disaggregated and restructured, it has been necessary either to commoditise or otherwise to formalise arrangements as a substitute for centralised decisions. Contracting for TMR is an example of this. In particular it has been necessary to revise the approach to planning, as decisions about generation and transmission are managed by different parties, at different times, and with different incentives and associated risks. This transition is still underway in Alberta, although it is well advanced. At least conceptually, market reform implies:

- For the system operator and planner (now functions of the ISO), a considerable shift away from the fully integrated management and planning of the industry to a role that is more akin to the impartial oversight and implementation of market rules in a wider sense;

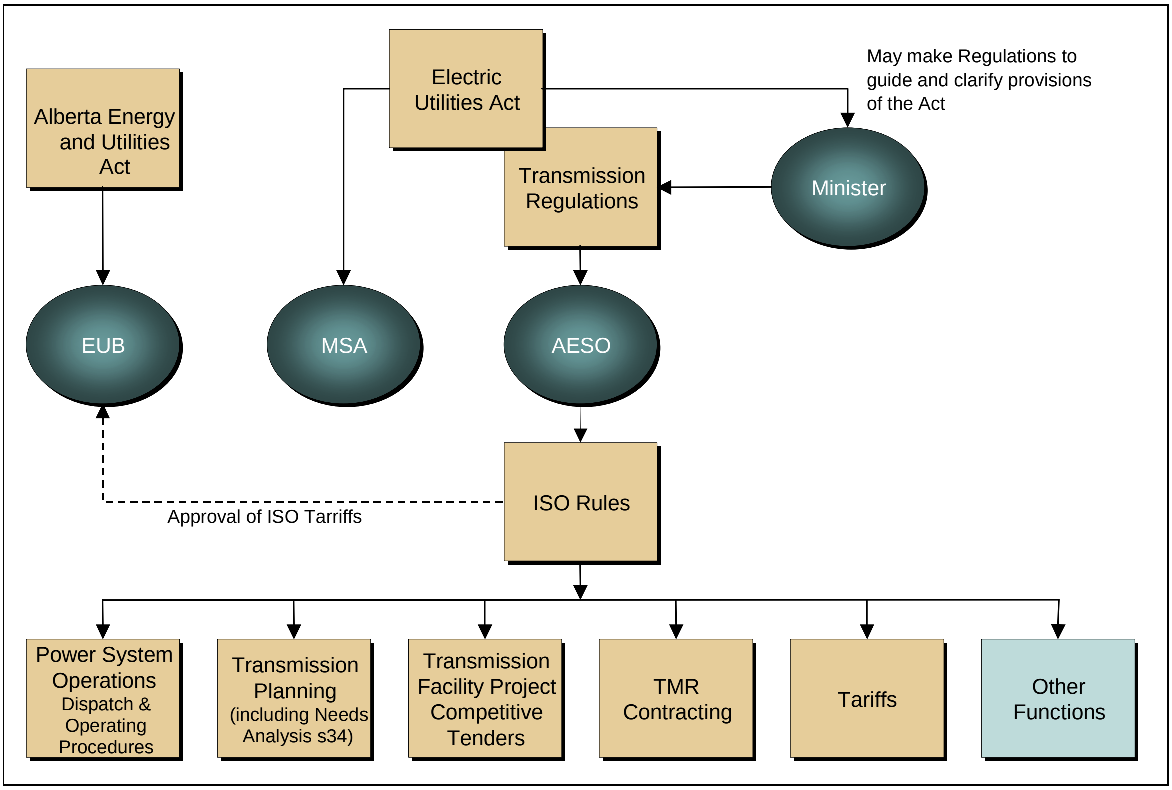
- For market participants, the right to act in a profit-maximising and independent manner within the framework of the market rules, but also to bear the financial consequences if outcomes do not turn out as anticipated; and

- Unbundling of governance and, where appropriate, creation of new bodies responsible for market rules, market operation, network planning and investment, power system operation and market oversight and regulation.

The broad responsibilities of the government and key bodies in Alberta at present are illustrated in Figure 1, which represents:

- The relationship between the EU Act and the different functions of the ISO, including as network planner, power system operator and tariff administrator and 'keeper' of the market rules provided for in the Act;
- The authority of the Minister to make Transmission Regulations under the Electric Utilities Act that are binding on the AESO; and
- The authority of the AEUB acting under the Energy and Utilities Board Act to approve Tariffs proposed by the ISO.

Figure 1: Alberta Electricity Wholesale Market – Governance Arrangements



2.2. TMR IN THE ALBERTA WHOLESALE MARKET

In common with many other reformed competitive markets in electricity, Alberta employs a commodity approach for energy trading. Some markets, including Alberta, also commoditise energy reserves that are procured through an ancillary service exchange or through over-the-counter trading arrangements. 'Non-exchange' ancillary services – blackstart, TMR, voltage support, and remedial action scheme services – are procured via requests for proposals (RFPs), via direct negotiation or if system security is threatened, through conscription.[4]

2.2.1. Wholesale Spot Pricing Arrangements

To some extent, the separate, non-exchange procurement arrangements for TMR services are a consequence of the fact that the Alberta power pool posts a single market-clearing price across the Province. A single electricity price reflects the overall demand-supply balance, but not specific locational requirements, as there are no locational prices to signal more efficient locations for generation (or other forms of) investment.

It would be possible to develop a highly granular approach to energy pricing, for example a nodal pricing system, to create incentives for locational responses and prices for energy and TMR. Locational energy prices would reduce but not entirely eliminate the need for separate procurement arrangements for some ancillary services now provided in TMR, since they would apply only for energy (MW), whereas some network solutions require reactive power and fast acting control systems.[5] A locational pricing regime would also have far reaching consequences for the operation of the overall energy market, and as a matter of high-level strategic policy this path has not been followed in Alberta. This position is a given for the purposes of our analysis.

The Policy complements the single energy price design with a network investment regime that will all but remove instances of congestion that might lead to locational price differences, at least for in-merit generation as determined by the AESO in its planning process. This represents a considerable change from previous arrangements that essentially implied a gap in the market design.

The previous policy allowed for economically justified congestion to occur and relied on 'out-of-market' solutions to purchase locational transmission support services in Alberta.

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4 See for example John H. Kehler, ESBI Alberta Ltd., Canada, "Non Exchange Related Ancillary Services in Alberta", EUCI - Ancillary Services Conference April 10-11, 2002.

5 It is also worth noting that granular pricing arrangements often bring with them concerns about market power and uncertainty about whether operating patterns and new investment will respond adequately to ensure reliability of supply is maintained. We understand from presentations by representatives of the ADOE that this was a consideration in the decision to adopt the Transmission Development Policy.

Despite a number of attempts, TMR arrangements were not able to balance competing objectives for competitive pricing, reliability and return on investment to investors. As a result these arrangements have been unstable and have been altered a number of times. In addition, there have been a number of disputes and rule changes associated with the pricing and dispatch of plant under contract and compensation when the ISO conscripts service for TMR duty.

2.2.2. System Expansion Related Pricing Approaches

In 1998, EAL, the then network planning body, proposed System Expansion Related Pricing (SERP) credits to incentivise generators to locate where local network support services were required. While SERP was rejected as a solution by the AEUB, it was the precursor to two approaches for procuring non-wires alternatives to transmission expansion to deal with congestion:[6]

- *Invitation to Bid on Credits (IBOC)*: This was intended to deal with shorter-term critical congestion issues in Southern Alberta; and

- *Locational Based Credits – Standing Offer (LBC-SO)*: The SERP credit represented the ceiling price for LBC-SO RFP processes. The TA determined the starting point for the energy credit, and the credit was stepped up in stages to attract auction participants.

In February 2000 the AEUB discussed the rationale and proposed application of the SERP credits in some detail.[7] The original SERP proposals were an element of the EAL tariff designed to send a locational signal in the form of SERP charges and credits to the owners and operators of generation units, including existing units. While the AEUB substantially modified EAL's original proposals, it found that the SERP approach had a number of advantages:

- A long-term transmission plan would be published annually;

- The areas of constraint would be identified;

- The SERP charges/credits for the generation alternative would be published; and

- The information would be made public and available to potential investors.

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6 See Appendix D for an overview of IBOC and LBC-SO pricing arrangements.

7 AEUB Decision 2000 – 1, ESBI Alberta Ltd. 1999/2000 General Rate Application, Phase 1 and Phase 2.

Following its review, the AEUB found that a system of credits only, applied to new generation locating within Alberta, would be more appropriate. Existing generators would not be in a position to relocate in response to these signals, SERP would potentially distort the merit order and there were concerns about cost over- or under-recovery if a system of credits and charges was introduced.

The AEUB then decided that a system of credits should only be applied to determine the ceiling on prices that could be paid for new generation at desirable locations. Limiting SERP to credits would be more appropriate, since:

- This would make a difference with respect to the efficiency of the locational signal;
- The SERP credits would provide an objective and unbiased method of determining the ceiling that could be paid for generation at new locations;
- Published credits would provide greater transparency and an understanding of the maximum incentive that could be paid by location; and
- This would also provide an indication of the maximum increase in transmission tariffs should the locational credits fail to attract the needed generation and transmission facilities.

The AEUB then considered that a Standing Offer (SO) process using a system of SERP credits would be the preferred alternative to addressing transmission constraint issues in Southern Alberta and directed EAL to utilise a SERP-based SO process:

- In the event of over subscription, it would be market driven and could lower costs;
- Through increasing steps of offer prices, it would be market driven and could lower costs even when not over subscribed;
- It would target the specific area or problem in question and only offer incentives to those parties providing a solution;
- It would be sufficiently flexible and transparent, in contrast to what some parties portrayed as a drawback of RFPs, to ensure that incumbents did not enjoy any unfair advantage; and
- The ceiling price for the SO would be economically determined by the present value of the avoided cost of the transmission alternative.

A RFP would be the preferred backup in the event that SO failed to attract sufficient generation capacity.

A summary of contracts established under the IBOC and LBC-SO in the Northwest Region is provided in Appendix D. A number of these were long-term contracts with terms up to 20 years. These processes were revised and refiled a number of times, and in a subsequent decision, the AEUB emphasised that it would not approve any further SO unless such applications were accompanied by a rigorous demonstration of need and substantiated in EAL's ten-year development plan.[8] Nonetheless, a number of situations were identified where network congestion could not be economically removed through the construction of networks (wires solutions), either in the long term, or for a transitional period pending network augmentation.

Between July 2000 and July 2002 the EAL entered into a number of agreements for TMR services in the Calgary, Southern Alberta, and Grande Prairie areas. These contracts essentially provide for additional payments to TMR service providers to offset the fact that there are circumstances when (spot) market revenues alone would be insufficient to incentivise generators to provide this service.

2.3. Market Versus Regulated Arrangements

TMR is thus a service that sits uncomfortably at the boundary between the regulated and competitive sectors. As a general matter, it is difficult to avoid a combination of regulated and competitive arrangements for transmission within a reformed electricity sector. Energy is traded through a combination of contracts and a pool with a single marginal clearing price across the Province, as discussed above. The network, on the other hand, is essentially regulated. Division 2 of the EU Act requires owners of an electric utility (including isolated generating units, transmission and distribution networks) to prepare a tariff and apply to the AEUB for approval of the tariff.

For TMR providers, the single price for energy within the Province is an important characteristic of the market design. The single price cannot reflect the value of network congestion that is the basis for the existence of TMR. The TMR generator must then rely on a TMR contract or compensation for conscription especially when the market price is below its cost and it is 'out-of-the-money'.

8 AEUB Decision 2000-76, ESBI Alberta Ltd. Part C: 1999/2000 Phase I & II Tariff Application, Location Based Credits – Standing Offer.

2.3.1. Implications for TMR Pricing

Our interpretation of the debate between the parties about the pricing methodology is that this is essentially one of disagreement about whether pricing should be based on energy market outcomes adjusted for any operation that is uneconomic, or as a substitute for a long term regulated transmission assets. This is a relatively simple but key philosophical issue and goes to the heart of an assessment of the pricing principles that might apply for these arrangements:

- In the past, TMR was considered as a long-term substitute for transmission, and this logically lead to the use of a long-term regulated cost of service approach that was potentially unrelated to energy market returns;[9]

- However, as the market was deregulated, and in part as a result of a poorly designed contract structure, TMR providers received revenues well in excess of regulated returns, prompting a review of TMR pricing arrangements by the AESO and the current application for a review of the TMR pricing arrangements before the EUB; and

- TMR providers are increasingly affected by this distinction as energy prices have fallen considerably during the course of the debate.[10]

These fundamental differences also appear to be reflected the circumstances of the Rainbow Lake dispute. Our understanding of this dispute is as follows.[11]

- ATCO owns three old low efficiency gas turbines (Rainbow Lake units #1, #2 and #3) installed since 1968 with a total capacity of 90 MW.[12]. In 1999, ATCO constructed a 45 MW cogeneration plant (Rainbow Lake unit #4). No TMR contract was in place to finance this unit.

9 MSA Note, "Regulatory History" (undated).

10 We note that for constrained-high cost locations the fall in energy price does not necessarily mean that the cost of TMR has fallen.

11 Affidavit of Grant Lake before the Alberta Energy and Utilities Board, Alberta Electric System Operator, Application No. 1357161, Application to Amend Article 24 of AESO'S Approved Terms And Conditions of Service (Lake Affidavit).

12 ATCO, while it is the owner of RB1-3, does not hold dispatch rights. These are held by Duke Energy through the Rainbow PPA. Currently RB 1 and RB 3 are currently not available to run because Duke has chosen not to make Non-routine Maintenance (NRM) Payments under the PPA. The Rainbow PPA expires December 31, 2005.

- An interim agreement was entered into with the TA (then EAL) on December 22, 2000 with an undertaking to enter into a "formal long-term binding TMR supply contract" to provide TMR service. On July 6, 2001, the TA entered into a TMR contract with ATCO to add a second 45 MW open cycle plant (Rainbow Lake unit #5). The Rainbow Lake units #4 and #5 TMR contracts were consolidated effective May 1, 2003.[13]

- On April 30, 2003, the Rainbow Lake units #4 and #5 TMR contract was extended for a period of one year by the AESO, which had taken over the responsibilities of EAL to administer the transmission system as TA.

- In May 2003, ATCO approached the AESO to negotiate a 15-year TMR arrangement that would include the provision of TMR service from all of the Rainbow Lake units. The proposed pricing methodology was to allow for recovery of fixed costs including a reasonable return in respect of these units. No agreement was reached with the AESO.

- After giving notice in late 2003 the AESO did not renew the contract on April 30, 2004 and commenced conscripting service under Article 24 of the AESO Tariff.

2.3.2. Role of the AESO

The tension between market and regulated arrangements is also reflected in the different roles of the ISO. This will in part be clarified by the Policy, which aims to present the foundation principles, recommendation and supporting rationale for a sustainable transmission development policy in Alberta.[14] Many of these principles impact on the broader role and responsibilities of the ISO. In particular, the ISO must:

- Assess the current and future needs of market participants, plan the capability of the transmission system to meet those needs and arrange for transmission system upgrades as necessary;

- Develop planning and operating standards and criteria for the Alberta transmission system in consultation with stakeholders;

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13 ATCO claims that the understanding between the parties was that the TA would use reasonable commercial efforts to renew the Rainbow Lake units #4 and #5 TMR contract annually as long as services were needed. This appears to be disputed by the AESO.

14 Alberta Energy Electricity Business Unit, "Transmission Development The Right Path for Alberta, A Policy Paper", November 2003.

- In accordance with the Policy, proactively plan transmission development to achieve 95% 'congestion free' transmission so that under normal operating conditions, 100% in-merit generation can be dispatched;[15]

- Have the flexibility to consider TMR contracts where they are technically viable and a superior alternative over the long-term in limited cases. However, subject to the clarification of the Policy, transmission development will eliminate much of the potential need for TMR as a result of the reduction in congestion. Further, where transmission constraints cannot be removed, TMR arrangements may be employed but should:

  - Not set or distort market prices;

  - Be provided on a cost-of-service basis by the owner; and

  - Should not be a vehicle for exercising market power in a region that is transmission deficient.

The objective of reducing congestion is also reflected in the Transmission System Criteria and Reliability Standards of the Transmission Regulation.

The ISO is then at once in a position that is simultaneously powerful, but very exposed because:

- As the system operator, it is the monopoly purchaser of a range of network support services (including TMR) from a variety of market participants. The AESO's counterparties have the choice of either selling their services to the AESO, under terms and conditions agreed to by the AESO, or not selling them at all, but subsequently be at risk of conscription and payment of compensation under Article 24 of the network tariff; and

- At the same time, reliability of the Alberta power system is very high indeed on the public agenda, as it is in other wholesale markets, and the adverse political and economic consequences of unreliable electricity supplies are considerable. On occasions when reliability is under threat, the AESO can, however, conscript services from participants, including those who previously have been unable to reach agreement about commercial terms for a contract. This is of course well-known to all parties, and the risk of an adversarial relationship is potentially that the bargaining stakes are raised to such an extent that one party may simply 'refuse to deal'.

Section 4 reviews the corresponding contracting behaviours of the parties in some detail.

15 The 95% criterion is intended to be a guideline, rather than an absolute number.

2.4. SUMMARY

In practice, most power systems, including that in Alberta rely on a combination of market based generation and network, including TMR-type arrangements, to maintain security and reliability of their network. Under the Policy, Alberta relies on the planning function of the ISO to ensure there is an adequate match between the generation and transmission capability in different parts of the network. As a result the pricing mechanism in the Alberta power pool does not provide for location-specific payments to generators. While such locational prices might assist in competitively pricing TMR services when there are a number of actual and potential providers at a location, in other situations how TMR services should be priced raises difficult questions.

Historically a range of approaches has been applied in Alberta to compensate participants for the provision of TMR services. Out-of-market approaches, including the IBOC and LBC-SO payment mechanisms, applied a pricing philosophy that used the avoided cost of transmission investment as a ceiling for the locational credit.

However, when the Alberta wholesale market was restructured, historical TMR arrangements resulted in very substantial payments to participants. The AESO considers these to be unreasonable. This view has led the AESO to not renew a TMR contract and instead rely on conscription under its mandate to maintain reliability of supply and also to apply for a change in the relevant provision of the Alberta Electric System Operator's Tariff.[16]

More generally the ISO has a number of potentially conflicting roles and technical commercial objectives. How it balances these is the crucial to the creation of a fair, efficient and openly competitive market.

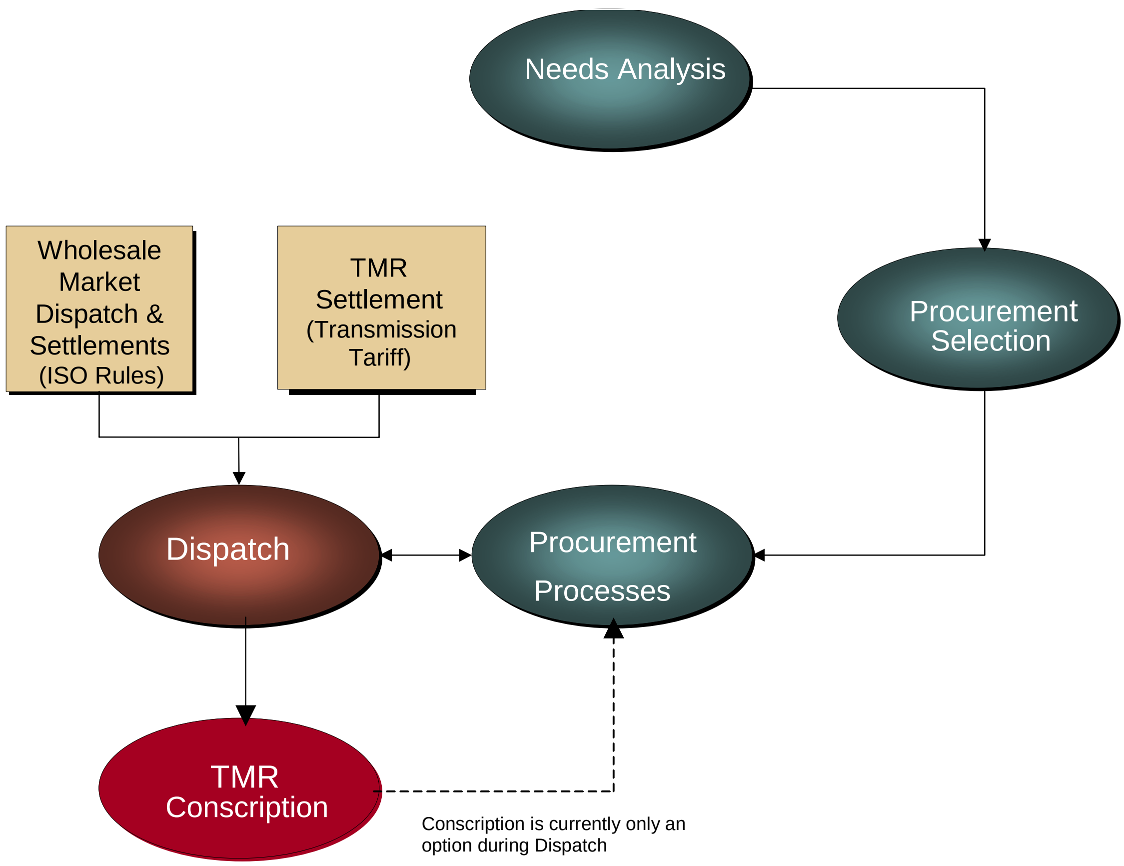
16 Alberta Electric System Operator, Article 24 Amendment Application, August 16, 2004.

3. REVIEW OF TECHNICAL ISSUES AND PROCESSES

Decisions about the amount, nature and location of TMR 'needs' are taken on the basis of engineering studies. These focus first and foremost on TMR requirements to meet relevant technical standards for a given level of network investment, and detailed planning policies. On the basis of identified TMR needs, procurement processes are entered into. The ISO then procures and dispatches TMR services as part of its wider transmission planning and system management responsibilities under the ISO Rules. Figure 2 below illustrates the chain of responsibilities and different functions and sets the context for this and subsequent sections of this report.

Market participants are expected to consider the terms of the TMR contracts, including likely dispatch patterns and corresponding payments, and broader energy market opportunities in deciding how to participate in the procurement process. Failing timely agreement, the ISO is able (and has exercised this right) to conscript generating units to provide required TMR services during the dispatch process but has not to date employed conscripted contracting.

Figure 2: Alberta TMR Acquisition Process



A key issue in the analysis that follows in Section 4 is the interdependence of these technical and commercial processes. That is, it appears to us that in undertaking its technical assessments, the AESO has effectively already taken into account commercial factors (such as likely spot market dispatch) that are strictly matters for the judgement of the (private sector) counterparty. However, the overall cost of TMR provision and the objective of promoting competition will both be affected by decisions about need, procurement processes and outcomes.

It is therefore important to understand both the technical criteria and operational use of TMR in order to adequately assess the fairness, efficiency and openness of competition. This section sets the scene for analysis by reviewing the technical aspects of these arrangements, the range of supply options available, and the nature of the procurement processes.

3.1. Determinants of TMR Requirements

The amount and nature of TMR the ISO identifies as necessary to procure is a crucial factor in determining how competitive the process can be. For any network there are two key factors that determine the amount and nature of TMR that is required, these are described below.

3.1.1. Network Engineering Objectives

The ability of a section of network to support power flows within safe operating limits or without resulting in congestion leading to out-of-merit dispatch, is affected by a complex range of technical parameters. The most readily understood limitation is a thermal restriction where a particular transmission element cannot safely carry more than a specified amount of power without exceeding safe operating temperatures. In other cases, low voltages following a disturbance may be the limiting factor and may be raised through either local MW generation reducing transmission flows in a section of the network, or through a local source of MVARs from either a new or existing generator or from additional reactive plant. In other situations, for example, in the Rainbow Lake area, the AESO's confidential studies indicate that the problem is post contingency voltage stability of a nature that only local MW generation is a practical response.[17]

17 We have sighted a confidential report from the AESO on this matter but have not undertaken a technical audit of this. There will certainly be situations where this is the outcome, and our interest here is the implication for TMR in general.

3.1.2. Assumptions about Key Parameters Impacting on Network Loading

The main factors that determine the loading in a particular part of a transmission network are customer demand and output of generators. TMR contracts with generators are designed to ensure that the contracted generators provide specified outputs to ensure transmission loading is within safe limits as determined by the relevant performance and policy standards for the power system.[18] Forecasts of customer load at different points on the network are thus crucial in determining the need for transmission and TMR.

However, in a competitive market, forecasts of output from uncontracted generating units participating in the market are far more problematic than in a centrally planned environment. The Rainbow Lake area of the Northwest region is an example where much of the installed generating capacity is assumed by the AESO not to be operating in the normal course of the market, primarily for economic reasons, as the operating cost of these plants is often well above the revenue that can be expected from the market. TMR contracts are then used to pay the owners of these plants for running 'out of merit'. In other cases the situation is not as clear-cut, but has a major effect on the amount of TMR needed. For example, there are cases where the AESO has not renewed a TMR contract as it expired based on its assessment that the particular units would run in the energy market regardless.

Such assessments and assumptions are an unavoidable part of network planning and their use in principle should not be contentious; but their impact on facilitation of competition in a market situation is problematic. The substance of those assumptions can be crucial in determining requirements, cost and available information. The process by which they are reached affects the transparency of the ISO's decisions and are part of the overall package by which perceptions of fairness and confidence are built.

Importantly the assumptions can also inadvertently narrow the potential scope of providers and hence reduce the level of competition. Depending on the identified requirement and underlying assumptions, costs can then differ markedly between TMR solutions. The best way for such information to be revealed is by a systematic, transparent process that pre-judges circumstances of delivery to a minimal extent.

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18 The technical performance standards are established in the Transmission Regulations and relevant external interconnection standards of the Western Electricity Coordinating Council (WECC). We have not, as part of this review, assessed the application of those standards in Alberta but note that we are aware that elsewhere in similar situations subtle changes in interpretation of standards, for example the classification of certain events as a single contingency or the length of time an overload is permitted to exist, can make a material difference to operations. However, should any changes be considered to the application of the standards, this would affect overall efficiency and the point at which TMR was required, but not fundamentally alter consideration of competitiveness.

3.1.3. Role of Transmission in the Wider Market Context

There is an important wider market and policy dimension to defining what TMR services are required. Specifically, the Policy sets out wider governance objectives of key bodies, and how these are translated into transmission planning and procurement processes. The previously noted changes to the transmission policy are likely to substantially reduce the extent to which TMR services will be required and procured in Alberta in future.

As noted, TMR is a service that substitutes for transmission. This can be a temporary situation pending construction of additional transmission, or it can be long-term where transmission is not the most economic solution. The objective for transmission is crucial in deciding if transmission or TMR is appropriate at all, and if so, which type. In general, objectives for transmission can be expressed in terms of reliability of supply or, as is the case in Alberta under the Policy, also consider level of congestion or, even more precisely, limitations on the dispatch of in-merit generation in the market.

Since the beginning of the reforms of the Alberta wholesale electricity sector, a number of different philosophies have been applied in relation to the role of transmission. TMR arrangements have been affected by significant restructuring of key market institutions, in particular the transition between the TA and the AESO, and a number of different approaches were employed to reach commercial terms and conditions for TMR. For example, in ESBI Alberta's Annual 10 year Transmission Development Plan for 2002-2011 published in March 2002, ESBI Alberta advised in section 6.3.3 in relation to the Northwest Region that there was a significant amount of plant operating under locational incentive arrangements, and that *"ESBI is in the process of completing some financial modelling to determine if there is a combination of reduced transmission expansion and a small volume of TMR that gives a lower overall cost"*.

The Policy clearly supersedes this approach and introduces a new regime that appears to be interpreted by the AESO as authorising TMR only as an interim measure pending construction of network, or if there was a very significant, but as yet unquantified, cost advantage from a TMR solution. These and other changes over time have resulted in a relatively unstable environment for TMR. In discussions conducted as part of this review, the majority of TMR providers criticised the changing environment and lack of clarity about need, and this has contributed to our assessment of a lack of fairness, efficiency and competitiveness to date. It is also inconsistent with principles of dynamic efficiency afforded by a credible, stable market environment.

3.1.4. Transmission Regulation

The Regulation to implement the Policy sets out high level circumstances when the ISO may apply non-wires solutions to manage identified reliability issues. In considering the design and planning of the transmission system, the ISO may consider specific and limited exceptions to its planning requirements and propose a non-wires solution including:

- In areas where there is limited potential for growth of load, and the cost of the non-wires solution is materially less than the life-cycle cost of the transmission wires solution, compared over an equivalent study period; or

- If the non-wires solution is required to ensure reliable service due to the shorter lead time of the non-wires solution, for a specific limited period of time.

The AESO's views noted in the previous section are consistent with this, but lacking in detail about what constitutes 'material', and whether the expectation is that there will be virtually no long term role for TMR or whether there may be niche uses. Importantly with respect to the recovery of TMR costs, the Regulation provides that for the purposes of section 30(2)(a)(ii) of the EU Act, the compensation must be no greater than an amount that would result in the recovery of fixed, operating and maintenance costs, including a reasonable rate of return, using a methodology described in the ISO network tariff. At the time of writing the AEUB was considering an application for a tariff but is yet to determine its position. Of particular interest will be how it proposes to treat fixed costs within TMR contracts. In our view this will need to carefully consider amongst other factors the time frame for recovery and in particular whether it will include accelerated recovery in the presence of future regulatory stranding. In addition the ISO must also make rules regarding TMR generation units and the determination of the pool price so that the pool price will be determined using the last *in-merit* generating unit dispatched.[19]

This highlights a subtle but important clarification that is needed in the application of the Transmission Development Policy, that is whether the policy is:

- Intended to drive wires based investment that allows network congestion to fall within the standards set out in the Policy; or

- Concerned with a regulated network business planning process using resources (including TMR) that are not also part of the energy market, to ensure that the congestion standard in the Transmission Development Policy is met.

At one level it is clear the Policy is designed broadly to ensure use of wires based solutions and reduce the use of TMR in most circumstances, but it also leaves room for economic decisions to employ TMR, possibly in the long term.

19 Our emphasis.

This is seen in evidence given on behalf of the ADOE to the AEUB hearing on the Edmonton-Calgary 500KV Transmission System Reinforcement Needs Identification in December 2004, where it is noted that TMR would be applicable in situations where cost of wires based solution was materially higher than a TMR solution.[20] The circumstances under which TMR might then be employed, is a matter for the AESO. Thus the Policy is expressed in terms of the amount of congestion but is being interpreted as being concerned with a preference for wires based development. The difference is subtle but significant for the design of all aspects of TMR arrangements.

3.2. TMR Supply Options

To a large degree, the nature of the requirements for TMR services determines which options are technically feasible and has a significant affect on the size of the pool of potential providers. The Alberta Interconnected Electricity System (AIES) covers a large geographic area, with a significant number of loads located in remote sections of the network. Given the existing structure of the network, the location of generation and load and their respective production and consumption patterns, a range of network support services have in the past been employed to support the stability and reliability of the transmission system.

The potential range of TMR options which the ISO may then consider has a number of dimensions, including locational specificity, technical, and operational requirements. The extent to which alternative suppliers of TMR services are substitutes varies, although TMR services in general can be provided via transmission, generation, and demand-side options. This has implications for the size of the ‘pool’ of potential providers and hence the potential competitiveness in the supply of TMR. For an identified TMR requirement and subject to the fundamental requirement to maintain network reliability, the broader the range of potential technical options to meet an identified need, the more participants can potentially bid to supply a service, and the more cost-effective the solution is likely to be.

3.2.1. Northwest Region of Alberta

Our terms of reference require us to consider the situation in the Northwest region and the Rainbow Lake Area in particular. At least in some parts of the Northwest of Alberta, a broader range of options – including MW or MVAR sources across the region can meet the relevant technical requirements currently supplied under TMR contracts. There would thus seem to be more scope for seeking substitute suppliers in these regions, since the technical requirements for TMR:

20 From para 2306, AEUB Transcript of Edmonton-Calgary 500 kV Transmission System Reinforcement: Needs Identification; Proceedings 20 December 2004.

- Tend to be less site-specific, hence allowing for potential suppliers across a larger geographical area;

- Are required for shorter periods of time, for instance, only during peak periods, and would hence include demand side options as well; and

- Are less technology-specific, and hence able to be provided by demand, reactive power as well as MW generation options.

Nonetheless, the application of the Policy across Alberta is likely to imply that much of TMR services will only be required for a limited timeframe, and that the payback period of any associated investment will be considerably shortened. The effect is likely to be the same as for the Rainbow Lake area – a reduction in the potential pool of providers and hence in the potential competitiveness of the service; while at the same time a reduction in TMR demand in the long term.

3.2.2. Rainbow Lake Area

Our understanding of the situation in the Rainbow Lake area indicates that the potential pool of likely competitors for TMR provision in that area is more limited. The Rainbow Lake area is characterised by specific site and performance requirements (needs):

- TMR is currently required within the local network north of Keg River. This would rule out a broad RFP to participants located within a wider geographical area;

- Our understanding is that AESO technical studies indicate a need for MW energy, rather than reactive power (MVAR) services, ruling out certain types of transmission solutions (such as static VAR compensators); and

- On the basis of those studies by the AESO, some TMR services are required on a 24-hour basis. This essentially eliminates consideration of demand side alternatives which are more suited to occasional peak lopping role.

In principle it would be possible to eliminate the need for TMR by augmenting the transmission network. Until now, this option has not been adopted by the relevant transmission planning bodies although we understand that transmission expansion is now planned for provision in this area from 2008, consistent with the Transmission Policy and Regulation.

TMR will continue to be required until then. Given the successful reduction of congestion its short run effect will be to reduce the potential competitiveness of supply options for TMR services in the Rainbow Lake area as only resources that are likely to be commercially viable within the market without TMR support after 2008 will be likely to enter to offer to provide TMR in the interim.

3.3. DISPATCHING TMR

TMR is dispatched in accordance with operating procedures developed by the ISO in its role as the power system operator. Historically TMR has been considered in two categories for dispatch and subsequent settlement:

- Contracted TMR; and
- Uncontracted TMR dispatched by the AESO under its power to conscript resources in emergency conditions.

The order in which TMR is dispatched is determined by the prevailing power system conditions and a pre-determined dispatch order contained in one or more OPPs promulgated by the ISO under the auspices of the ISO Rules. OPP 501, which deals with dispatch of TMR in the Rainbow Lake area, has been the subject of a number of changes.

ATCO Power considers that the AESO's change in operating procedure and termination of the contract was aimed at exerting pressure on it to enter into a new contract at lower prices.[21] In conversation, the AESO was adamant that negotiating positions have never and would never influence a dispatch order. Nonetheless, we are aware that the relatively frequent changes in the dispatch order that have occurred have been a source of unease among market participants and raise questions about the overall transparency of the AESO's processes. We understand the AESO's basis for changes in the dispatch order include that:

- The AESO had an (implied) obligation, to dispatch contracted facilities before it can conscript service from non-contracted facilities on the basis that it should minimise market distortion;
- Rainbow Lake 4, being a cogeneration facility could operate in the energy market without having to receive a TMR dispatch, and that had never been tested for many years; and
- The AESO would have to "pick up" a greater proportion of costs if Rainbow Lake 4 were directed. This would be in spite of the fact that this unit was relatively more efficient. This is consistent with how the AESO has balanced the multiple objectives with a bias to cost minimisation.

We further understand that changes in arrangements for dispatch have not been the subject of full public review consultation but were previewed by the directly affected parties. The dispatch merit orders were included in a confidential appendix to the OPPs, since these relate to private and commercially-sensitive contracts.

21 Lake Affidavit

It was also clear that the AESO and the relevant market participants were effectively playing 'cat and mouse' with dispatch order and bidding, with the AESO seeking to minimise its payouts (and hence cost to ratepayers) and market participants maximising profits from their market operations.

As a general point we note that a repeated bilateral monopoly game, if it is competitive and there is uncertainty, may well provide strong temptations to have different strategies played in different periods. In this situation, a transparent predictable dispatch arrangement over time may require a long-term agreed contract as to the terms and conditions of transactions (dispatch). There may be even more viable competition 'for the contract' than for short-term arrangements for supply.

3.4. BROADENING THE DEFINITION OF NEED

The discussion in the previous section focused on the scope for competition in the supply of TMR services. But, the nature of the procurement processes applied by the AESO may also play a role in determining whether the eventual outcome can broadly be considered 'competitive', that is, broadly long-term cost-reflective.

The amount, location and nature of TMR each have a dominant impact on the nature of the process that will be practical to acquire it. If, for example, only MW generation in a very limited area can address the problem at hand, then a broad RFP may not be appropriate. But, if MW, MVAR, load factor correction or demand side response from anywhere within an area could meet a TMR need, then a quite different acquisition process can be considered.

Within these limitations, our review of TMR procurement processes indicates that the processes adopted by the AESO have not necessarily been focused on attracting the greatest possible range of suppliers. There are several aspects to this, reviewed below.

3.4.1. Obligations of the AESO

The governance arrangements that apply to the AESO are relevant in this context. Of particular note for this examination of TMR is that since June 2003 the AESO has functioned under the auspices of the EU Act. Statute of Alberta, 2003 Chapter E – 5.1. includes a number of objectives relating to the activities of the AESO in relation to competition, including the overarching objective that (Part 2, 16):

> *The Independent System Operator must exercise its powers and carry out its duties, responsibilities and functions in a timely manner that is fair and responsible to provide for the safe, reliable and economic operation of the interconnected electric system and to promote a fair, efficient and openly competitive market for electricity.*

These objectives would suggest that it is crucial that the assessment of need for TMR and associated processes should be, and be seen to be, designed to promote competitive outcomes.

In our view, following changes to the EU Act in 2003 that introduced requirements for specific statements of need as part of the transmission planning process, the legislative and regulatory framework has not been a hindrance to achieving competitive processes.[22] However, it appears that the AESO's internal processes, at least as presented to external parties, has not been as assertively competitive as is possible. In particular, from the information available to us, the analysis of technical need undertaken by the AESO does not appear to have explicitly incorporated an objective of finding alternatives that would *promote* competition. Analysis focusses on technical considerations, which is clearly an essential component of a needs analysis, but is too narrow to transparently *promote* competitive outcomes. This view is also consistent with the recent findings of the AEUB in relation to the AESO's submission relating to network expansion in southern Alberta, wherein the AESO was directed to provide additional information about levels of congestion that would be required to demonstrate compliance with the Policy.[23]

Where various technical alternatives for TMR may be contemplated, these matters are, we understand, taken into account informally, and on a case-by-case basis, rather than through a formal and transparent process within the AESO.

3.4.2. Focus on Preferred Solutions and Bilateral Negotiations

We now turn to the process for procurement of the amount and type of TMR that has been identified as needed. Discussions with the AESO indicate a lack of formal processes for selection of TMR procurement, and a preference for bilateral negotiations with identified counterparties, rather than wider RFPs. The AESO indicated that:

- While different processes have been adopted along the way, in recent years the AESO has moved down the path of primarily entering into bilateral negotiations for ancillary services;
- The AESO has no formal processes in place for deciding on the best procurement process; and
- The TA has always had a preference to negotiate with existing facilities.

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22 Clause 33 of the EU Act states *"The Independent System Operator must forecast the needs of market participants and develop plans for the transmission system to provide efficient, reliable and non-discriminatory system access service and the timely implementation of required transmission system expansions and enhancements."*

23 AEUB Decision 2004 – 075.

Earlier we noted that we believe the procurement of TMR services requires some degree of judgement in terms of the technology that is considered, and this may have implications for the potential pool of providers. However, it appears to be an ad hoc process for considering the tradeoffs that might be involved. For instance, in relation to TMR services for the Rainbow Lake area, the AESO noted that the Rainbow Lake units were capable of providing the TMR services for some time and that the AESO had made corresponding contributions to their fixed costs, and that "*it just makes sense that ATCO were the most competitive solution*." While this may have been the case in this specific circumstance, it is not clear whether in general the AESO has distinguished sufficiently between its own view of the preferred provider, and how a competitive procurement processes should best be managed in practice, and in the interests of openness, transparency and revelation of information, be seen to be managed.

This seems also to be inherent in the AESO's view of plant operations and is related to the assumptions made during needs analysis discussed in Section 3.1.2. For instance, in relation to the operations of HR Milner, the AESO commented that the decision was taken not to recontract as this was a baseloaded unit and would likely operate in any case, and that it would not be sensible to provide an out-of-merit guarantee to a baseloaded coal plant which would effectively change their economics, in terms of their operation in the energy market. Hence the AESO took the decision to let that contract lapse.

As a general matter it would seem that by exclusively focusing on a specific provider and excluding others based on judgements that seemingly placed low weight on competition and others' responses, the AESO would tend to place itself in a disadvantageous bargaining position from the start. A competitive market stance would suggest that all efforts should be made to keep as many parties and technologies 'in play' for as long as possible. This is reflected in our proposed process for the future presented in Section 6.

3.4.3. Perceived Shortcomings of Internal AESO Processes

This section includes views from TMR providers including a number that are critical of the manner in which the AESO has acted. It should not be a surprise that the AESO, with its multiple powers as market maker, system operator and commercial negotiator is criticised by for-profit counter-parties to negotiations with the AESO, or that those counter-parties may attempt also to influence the regulatory environment. However, we also note that the criticisms were made by market participants, through the MSA, in the context of a formal investigation by the MSA and should be given weight as a result.

In the course of our work there have been suggestions put to us by participants that the processes adopted by the AESO may have been lacking overall in terms of timeliness and rigour. We note here that from our understanding of the timing of a number of the processes some of the criticisms and lack of confidence may span the time network planning was undertaken by the previous TA as well as the AESO.

For their part, the market participants interviewed by the MSA expressed misgivings in relation to the timing and commercial conduct of processes adopted by the AESO and TA. In conversation, different participants:

- Expressed a frustration that the AESO did not seem willing or able to formally express the precise nature of the need for TMR, thus complicating commercial negotiations;
- Questioned the planning processes that had been undertaken, which had excluded contracting for MVARs from certain identified power stations;
- Identified what appeared to be poorly planned and timed processes, for instance in relation to stability issues in the Calgary area;
- Highlighted a failure to respond in a timely manner to identified contingency issues in the Edmonton area;
- Took issue with the independence of the AESO, with the general absence of expression of need, with the lack of transparency, and with, what was considered to be, a “substandard, irresponsible” analysis.
- Had “a general impression” that the AESO had considered other competitive alternatives to procuring the Brazeau fast ramp service, but had not seen technical documentation outlining technical needs. The procurement process had been specific to this service. The particular Participant commented that it did not consider that sufficient time had been allowed between need identification and contract signing. They could not comment on whether this would be considered to be an open process.

A participant in TMR procurement processes for a number of years, including in the LBC-SO processes conducted by the previous TA and more recent TMR processes undertaken by the AESO, expressed considerable frustration with the needs analysis undertaken by the TA at the time. They considered that subsequent poor commercial outcomes resulting in liquidated damages payments they were required to pay were, at least partly, the result of this.

In relation to the AESO, the Participant highlighted concerns about the lack of transparency in information made available to participants. Hence the AESO appeared unwilling to share information about replacement TMR purchases or the termination of IBOC agreements. Questions were raised about the AESO’s mandate to operate a fair and efficient market, and noted its impression that the AESO was currently pursuing a range of conflicting mandates, with no one mandate really being served well as a result. Specifically in relation to the current Calgary area TMR RFP, the Participant considered that the scope for liquidated damages would impose commercially unmanageable risks on the TMR provider, and was reserving judgement on whether it would be willing to participate in the RFP.

That Participant also raised wider questions about the market impact of the Transmission Development Policy. At the time they took the decision to invest in generation capacity, they considered there had been an understanding that the locational signal of the IBOC/LBC-SO could be relied on as a longer-term mechanism. In effect, the new Policy has undermined the basis for historical agreements. As a general matter, existing investors in generation had little confidence that markets and market structure would be allowed to work, and this was impeding investor confidence.

In the circumstances we have not attempted to assess the veracity of the specific criticisms, as this would require a comprehensive assessment of events over a number of years that in the end we believe is not warranted. This is because unless there is a reason to oppose a broadening of the scope of analysis and enhancement of transparency to demonstrably comply with the provisions of the EU Act, then the substance of these criticisms can be addressed relatively easily.

At a technical level we expect this will likely entail change to the objective for analysis of need and some change to internal process, but not fundamentally change it or compromise objectives related to reliability. The position that the AESO takes on the balance between cost minimisation and promotion of competition will be more transparent as a result. This in itself will be beneficial to the promotion of competition as required by the EU Act, but the degree to which that AESO amends that balance will be a matter of policy.

3.5. Findings and Recommendations

3.5.1. Scope for Competitive Supply

Given the locational and technical criteria that apply for identified TMR requirements, we concur with the AESO that across the Province there is likely to be a spectrum of more or less ‘competitive’ situations involving a lesser or greater number of potential TMR suppliers. Our assessment is that:

- It is unlikely that a fully competitive process can be run for TMR in all circumstances (see section 3.2.2);
- In respect of the Northwest of the Province generally, conditions are potentially competitive, in the sense that an RFP and/or competitive round of negotiations will be possible with a number of parties in some cases;
- In respect of load pockets such as the Rainbow Lake area, conditions are such that it is unlikely that a fully competitive process will be appropriate; and
- The competitiveness of TMR services in general is likely to further reduce as the time horizon for the supply of these services shortens, and any private sector investment potentially reliant on TMR becomes increasingly uneconomic.

3.5.2. Competitiveness of Procurement Processes

Previous procurements have had a strong central planning approach to identifying needs. The AESO has approached parties which they believe meet those needs and used bilateral agreements to negotiate the procurement of TMR services to achieve the lowest short term procurement cost. This has resulted in situations with a sole buyer, the AESO, bargaining with one or more (but in any case a very limited number of) potential suppliers. This situation is some way removed from any idealised notion of open competition. In these circumstances, the terms under which TMR services are provided can be expected to depend on the objectives and relative bargaining positions of the various parties, as well as the 'rules of the game', or procurement processes that are applied in practice.

On the face of it, the AESO does not appear to us to have pursued opportunities there may have been to increase the potential pool of suppliers in order to solicit competitive offers for TMR service, in terms of:

- Explicitly seeking as broad a range of technical options as possible that could meet an identified need for a given service;
- Developing a considered view on the merits of holding wider RFPs, instead of directly entering into bilateral discussions with *a priori* selected participants; and
- Undertaking any such negotiations in good time and with sufficient advance preparation to ensure that it was not reliant on the goodwill (which may or may not have existed) of potential suppliers.

We also note that some of the criticisms raised by market participants would imply concerns about the overall transparency of AESO's processes, and the accountability of the AESO in terms of delivering timely and well-considered network outcomes.

Nonetheless, it is worth reiterating that under the ISO Rules the AESO must balance multiple objectives. Given that the AESO appears to interpret its role at least in part as one of representing the interests of ratepayers (see Section 4), it may have felt under considerable pressure to procure TMR to preserve reliability and under what it considered to be reasonable terms and conditions from a reluctant monopoly supplier. But this also appears to have been at the expense of promoting competition and (dynamic) efficiency.

3.5.3. Technical Options for More Efficient and Openly Competitive Processes

The AESO's procedures and practices would be more aligned with the promotion of a fair, efficient and openly competitive process if the AESO's internal functions and processes exhibited greater transparency and separation.

The Planning Function

Planning should define the problem that is to be resolved using TMR or other network support services, and note the range of potential technologies that might be applied to deliver it. This would ensure that the concept of need was focussed on the problem (for example low voltages or overloaded network) in the first instance, rather than on a preferred or expected solution (for example MW generation). There should be an objective to identify as wide a pool of potential TMR providers as possible, by location, technology and timing.

If this analysis indicates that only a limited range of technologies can meet the underlying need, then it should be a requirement to demonstrate why this is the case. Where the technical analysis identifies tradeoffs in terms of the ability of different technologies to deliver a required service, this should as far as possible be quantified, and resolved in the course of any procurement stage. For instance, a less effective network support service may command a lesser price, but should not be prejudged, and in particular should not automatically be excluded from any procurement process.

The Operations Function

Operations should ensure it has all of the resources under contract or reasonably expects them to present in the market in order to operate the network within limits and without recourse to operational conscription, as a condition of "accepting the system as fit for service".[24] Short–term conscription should remain available to the Operations group to cater for force majeure situations where conditions emerge that are outside the design boundary as defined by the accepted technical design standards. But if the contracting process has been successful this will rarely be needed.

The Commercial Function

The objective of the commercial function should be focussed on determining and concluding the procurement of any and all service identified as technically warranted in the planning stage. Conscription by the Operations group should not be regarded as a valid planning or procurement device, however contractual conscription should be available under strictly controlled conditions. The nature and form of commercial procurement is discussed further in the next section.

24 In a similar fashion to the handover of a construction project to the owner /operator

Greater reliance of RFPs:

The AESO should review the merits of its stated preference for bilateral negotiations. While a formal RFP is likely to be more costly and may be more time-consuming, it may also deliver greater market transparency and increased pressure for a more rigorous analysis. Moreover, by focusing on a specific provider, the AESO risks:

- Signalling to the counter-party that there is no viable alternative service provider;
- Placing itself under increasing time pressure if negotiations do not proceed favourably;
- Engaging a process that limits information revelation about the market and its possibilities; and
- Violating fairness in process for all (potential) participants.

The case of the third parties expressing an interest in providing TMR services in the Rainbow Lake area is an interesting example in this context. Irrespective of whether the AESO was right in its conclusion that this would not represent a cost-effective option or be in the interests of rate payers, the threat of competitive entry could have been applied as a valuable negotiating strategy vis a vis ATCO. We therefore consider that the onus should be on the ISO to show that an RFP process is not the preferred option, rather than the other way round.

These are subtle changes in focus and scope of the Planning and Operations functions and are not expected to require dramatic change or detract from the engineering analysis currently undertaken. Rather, as an adjunct to the current analysis there should be explicit consideration of the opportunity for a range of technologies to address the basic technical need. This would include as appropriate MW generation, MVAR capability, demand side response, power factor correction and any fast acting control responses. Each of these should be explicitly considered and the assessment documented. If any are not technically feasible then the reasons should be stated and open to challenge. Cost should not, in the first instance, be a basis for rejecting a technology.

4. COMMERCIAL AND GOVERNANCE ARRANGEMENTS

The previous section described the technical environment and reviewed its impact on the competitiveness of TMR arrangements. The review concluded that changes to the level of transparency and scope of needs analysis would improve competitiveness and, by at the very least enhancing the openness of the TMR process, potentially facilitate a broadening of the range of providers.

However, the TMR procurement processes should also be assessed in the context of the overarching market and governance arrangements in the industry. In the course of the review of documentation and discussions with relevant parties it has become clear that TMR arrangements and associated commercial processes in Alberta are influenced by the wider industry governance framework. This section examines the impact of the framework and how each of the organisations with responsibility for TMR at different times have interpreted their obligations and exercised the discretions afforded by the framework.

4.1. AESO Governance Framework

The overall governance framework was introduced in Section 2 and illustrated in Figure 1. Key statutory provisions relating to the present dispute are set out in Appendix B, in terms of provisions in the EU Act, the Transmission Development Policy, and the Transmission Regulation. The EU Act and associated instruments make numerous references to the duties of the ISO.

4.1.1. Fairness, Efficiency and Competitiveness

The overarching role and responsibilities of the ISO are defined in Part 2, Division 2, Section 17 of the EU Act. Key responsibilities of the ISO include the requirements to:

> *Operate the power pool in a manner that promotes the fair, efficient and openly competitive exchange of electric energy (17(a)); and*
>
> *Direct the safe, reliable and economic operation of the interconnected electric system (17(h)).*

Sub section 17(c) defines the role of the ISO in the dispatch of electric energy and ancillary services within the Alberta region and between interconnections that impact the supply and demand balance of the region.

In respect of the ancillary services that the ISO uses to meet its obligations, it is required to:

> *Determine, according to relative economic merit, the order of dispatch of electric energy and ancillary services in Alberta and from scheduled exchanges of electric energy and ancillary services between the interconnected electric system in Alberta and electric systems outside Alberta, to satisfy the requirements for electricity in Alberta.*

Section 18 requires that

> *The Independent System Operator must operate the power pool in a manner that is fair, efficient and open to all market participants exchanging or wishing to exchange electric energy through the power pool and that gives all market participants a reasonable opportunity to do so.*

4.1.2. Prudence and the Public Interest

While the above objectives focus on the operations of the competitive market, there are a number of other provisions that the AESO believe are significant and have guided it in performing its duties.

Prudent Costs

The AESO noted that the ISO statutory duties and obligations include that it must act in a reasonable and prudent manner, and have referred us to the provisions of sections 17(f) and section 30(2).

Section 17 of the EU Act clarifies that the AESO must *"manage and recover the costs for the provision of ancillary services"*.

Section 30 (2) states that *"The rates to be charged by the Independent System Operator for each class of service must reflect the prudent costs that are reasonably attributable to each class of system access service provided by the Independent System Operator, ..."*.

Public Interest

Section 8, Subsection (9) of the EU Act requires that the members of the ISO (i.e. the Board) must conduct themselves itself in the public interest:

"*In carrying out any duty, responsibility or function as a member of the Independent System Operator, the member must*

> *(a) act honestly, in good faith and in the public interest,*
>
> *(b) avoid conflicts of interest, and*
>
> *(c) exercise the care, diligence and skill that a reasonably prudent individual would exercise in comparable circumstances."*

Reasonable Costs

The ISO is a not for profit entity (Section 14(3) EU Act). The AESO interprets this as a requirement that its costs are at all times reasonable, and notes that reference to a requirement to procure TMR services in a reasonable and prudent manner is also found in the Transmission Regulation.

Our review of the Transmission Regulation suggests that references to ‘reasonable costs’ only arise in the context of the AEUB’s obligation. Hence Part 6 – Board Responsibilities – states that:

(30) When considering an application for approval of the ISO tariff under sections 121 and 122 of the Act, the Board must

(a) ensure:

(i) the just and reasonable costs of the transmission system as a whole charged to the owners of electric distribution systems, customers who are industrial and persons who have made an arrangement under section 101(2) of the Act, and exporters, to the extent required by the ISO tariff, and

(ii) the owner payable by an owner of an electric distribution system is recoverable in the tariff of the owner of the electric distribution system;

(b) ensure owners of generating units are charged local interconnection costs to connect their generating unit to the transmission system, and are charged a financial contribution towards transmission system upgrades, and for location-based costs of losses;

(c) consider all just and reasonable costs related to arrangements and agreements described in section 9(5) of the Act.

4.1.3. Conflicting Interpretations of Objectives

There is almost inevitably a potential conflict between the objectives that any ISO faces in managing technical, commercial, and market operation issues, and this is also acknowledged by the AESO. These issues are common to most markets, and it is a very difficult area in which to get the balance right.

While we are not in a position to undertake a legal review of the range and hierarchy of objectives articulated in the EU Act and referred to above, we do note that the interpretation that the AESO appears to have adopted is not a straightforward one. The AESO places substantial emphasis on prudency, the public interest, and reasonable costs.

While there is no doubt that these principles are referred to in the various sources cited, they would appear to us to be guidance about how the duties and responsibilities are to be met and would accord with common practice in other competitive electricity markets. In simple terms, the ISO's duties and responsibilities can be summarised as to plan, design and operate a reliable power system in a manner that promotes a competitive market.

We note also that the term prudent is open to interpretation. There is presumably little argument that the ISO must incur sufficient cost to meet reliability standards, but this is given similar status in the Act as the requirement to promote competitive outcomes. We would therefore understand that prudence is not intended to mean lowest cost, but is equivalent to reasonable or fair cost to meet the organisation's duties and responsibilities.

In commercial terms this puts the ISO more in the position of a market maker between consumers and sellers of electricity rather than an agent of the ratepayers attempting to find the best deal for them. This accords with the words of the AESO referring to itself as *"an impartial body responsible for the planning of the transmission system"*. But, as evidenced by the views on pricing of TMR discussed in this section, this interpretation does not appear to be applied consistently.

Whatever the case may be, it is apparent that there is a need to clarify the role of the ISO. The Act contains potentially conflicting obligations that the ISO is implicitly required to balance, and at a minimum there is a case for review of the manner in which they are interpreted. The dual role of rule maker and party to a transaction introduces a conflict that is hard to resolve, suggesting close scrutiny by a body such as the MSA.

4.2. Competitive Versus Least-Cost Service Provision

Considering the specifics of the dispute between the AESO and ATCO Power - this has highlighted fundamental differences of opinion in relation to how TMR services should be priced and the primary objectives that the AESO should pursue in the context of a competitive energy market. The AESO's approach to negotiations with ATCO seems to reflect its interpretation of the nature of its changed responsibilities, from operating a centrally planned, integrated system to those of an agent of customers in a market environment. That is, the AESO appears to be working with a view on the least-cost method of service provision for the service from ATCO's Rainbow Lake units that may not reflect a market environment for provision of transmission.

Instead the AESO focused its negotiations exclusively with the provider of this service, although in hindsight they may have misjudged the size of these costs, as compensation has been significant and possibly above the cost of retaining the previous contract.

4.3. 'Reasonable and Prudent' Terms of Service

Section 2.3.1 noted that identifying the costs, and hence prices, of TMR services is not straightforward.

4.3.1. View of the AESO

The AESO's views on 'reasonable and prudent' terms and conditions for the provision of ancillary services were reflected in conversation in the course of this review where the AESO expressed its frustration with a participant who *"feels like ratepayers or the AESO or whoever has some obligation to pay them in a fashion that would keep them whole as if they were a regulated unit"* and that it should be up to investors and developers who build generation take the risk of return on and return of capital.

It is unclear how the AESO would apply this principle more widely, since it implicitly appears to distinguish between TMR pricing for existing, as opposed to new services. It is apparent the AESO recognises the risks to a generator locating in the Rainbow Lake area, for instance arising from constraints on the export capability of that area as it noted "….. *it's highly unlikely that greenfield generation will be there in time to provide the service or find enough value in a short-term TMR contract in order to trigger the development of a new facility*." And further *"... we don't think it's fair that participants have exposure to the energy market when the energy market is lucrative and heat rates are high, and then as soon as they drop and the energy market is not lucrative, that they get to put those assets to the ratepayers just because they are providing an ancillary service."*

The AESO's understanding of what would constitute a reasonable and prudent price for TMR services then seems to have played a major role in the course of the Rainbow Lake dispute and resulted first in the conscription of TMR units and subsequently in the proposed Article 24 amendment presently before the AEUB. In this regard the AESO noted that:

- Historic prices that may have once been assessed to be reasonable were no longer necessarily reasonable now or in the future, given changes in the legislative environment;[25]

- The obligation to procure TMR services in a reasonable and prudent manner was also reflected in references to TMR service provision on a cost of service (COS) basis as an upper limit in the Regulation and Policy; and furthermore

- Even payments based on COS were no longer a reasonable basis for determining TMR pricing, since:

25 Hence the AESO exercised its rights and allowed the TMR agreement for Rainbow Lake units #4 and #5 to lapse. The AESO considered that compensation paid under the Agreement was no longer reasonable.

- Reference to avoided costs of transmission were no longer relevant, as TMR services would only be required over a 3 to 5 year period before wire solutions would be implemented;
- Payments on the basis of COS would set a precedent, resulting in an increase in TMR costs from currently $55 million per year to somewhere between $150 – 200 million annually; and
- Payments on the basis of COS would only be appropriate for old, inefficient plants dedicated to the provision of TMR service, which have little or no value in the energy market.

4.3.2. History of TMR Pricing

To fully appreciate the environment in which negotiations for TMR have been occurring it is instructive to examine the history. Appendix D provides a brief summary of the evolution of TMR pricing approaches in the Province. Arguably the origins of the present dispute with ATCO and the wider ramifications of the current dispute relate back to the original market reforms, or rather, a failure to anticipate that in a changed market environment, generator participants would aim to extract maximum value out of any must-run service provision arrangements. That is, while the original Article 4 and 24 provisions appear to have envisioned payments under three relatively clear situations, i.e. TMR provision under contract, TMR provision in the absence of a contract, and TMR provision in an 'emergency' – these provisions were consecutively tightened as it became increasingly apparent that market participants would select those provisions under which they would maximise their revenues.

The AEUB's decision to repeal the offer price provision in Article 24.3(e) is telling in this context.[26] That provision allowed participants effectively to exploit their position in the spot market by offering TMR service at the spot price ceiling of $999/MWh, resulting in a very substantial increase in TMR costs. The AEUB concluded that reliance on Article 24(e) by Engage was designed so that the units would not be dispatched into the market, and this may well have been the case. At the same time, this behaviour:

- Was consistent with the incentives and opportunities provided to TMR generators by the Rules and Tariff, and was arguably predictable;
- Was problematic in terms of the expectations of participants contained in Part 1 (6) of the EU Act; and
- Is also likely to have been a major driver in the adversarial relationship that subsequently developed between the AESO and TMR providers given the view the AESO adopted of its role in managing price outcomes.

26 AEUB decision 2002 –13.

4.3.3. TMR Pricing Provisions in the Transmission Regulation

In our view the new Transmission Regulation will assist in clarifying the pricing principles that should be applied to TMR services. In relation to the recovery of must-run costs, Part 5 of the Regulation states that compensation must be no greater than an amount that would result in the recovery of fixed, operating, and maintenance costs, including a reasonable rate of return.

Our understanding from the AESO is that it has interpreted these broad principles in determining how costs should be translated into TMR payments. The AESO has outlined that in its view there are two ways to contract for TMR service :

- *A 'cost-of-service' approach*: This would apply to inefficient, fully depreciated units, where the AESO would pay the units' going-forward costs; and

- *A 'market based contracts' approach*: This would apply to newer, efficient units with significant in-merit energy periods. The focus of this approach is to 'keep the units whole' in terms of their variable costs. The AESO considered that this pricing approach could add significant upside to newer generating units, by making these more efficient and reducing their risk of any out-of-merit losses. As an example, the AESO noted that a recent market-based contract negotiated with a generator involved a sharing mechanism whereby the AESO would be credited with a portion of their in-merit energy profits.

The AESO considered that the expired contracts with Rainbow Lake 4 and 5 would fall under the 'market-based' contract heading, and would have guaranteed the units a profit in the order of $30 - $50/MWh. Nonetheless, the AESO did not consider these to be 'prudent', for two reasons:

- None of its other LBC-SO contracts provided for guaranteed profits over and above variable costs of a similar magnitude; and

- In the AESO's view, the Rainbow Lake #4 and #5 provisions would have been inconsistent with the upper pricing limit set out in the Regulation.

4.3.4. Economic Pricing Considerations

It is not clear to us that the AESO's interpretation of the TMR pricing principle set out above is necessarily well-founded in economics, and it is certainly not as straight-forward as the AESO argues. An economic discussion about the appropriate pricing of TMR services would naturally take as a starting point the cost of providing these services. Unfortunately, identifying the 'costs' of TMR is not easy, because network support services such as reliability are fundamentally produced 'jointly' with energy that is traded in the market.

Joint Production

Joint production processes arise when there are economies of scope; that is, the cost of undertaking two activities simultaneously is less than the sum of the costs of undertaking them separately. In the case of TMR services, joint or common costs arise in the fixed costs of the required generation capacity and variable O&M and fuel costs, although the provision of reliability services may create additional, separate fixed costs, for instance location-specific costs or in terms of greater flexibility required of the plant design. Similar examples arise in the oil & gas industry, where gas is sometimes a by-product – that is, produced jointly – with a 'primary' output, oil.

Pricing Principles for Joint Products

If a competitive market for reliability services existed, pricing for jointly produced products would not be an issue. Market forces would determine separate prices for electricity and reliability. But determining individual prices for jointly produced products within a regulated context is not straightforward. Costs are an obvious starting point, but to the extent that these are overwhelmingly incurred jointly, separate cost allocation rules make little practical or commercial sense. There is no argument that common costs should be allocated in a particular way between energy and reliability.

To answer the question how such prices should be set, it is useful to consider what would hypothetically characterise equilibrium that is economically efficient: two economic principles for allocating the costs of joint products should apply:

- The cost allocated to any product or activity should never be *less* than its efficient incremental costs, or the costs which would be saved by discontinuing that product; and

- The cost allocated to any product or activity should never be *more* than its efficient stand-alone costs, that is, the costs that would be incurred if only that activity or product were undertaken.

These principles define upper and lower pricing bounds: if the upper bound is violated the good or service can be supplied more cheaply whereas if the lower bound is violated the revenue (social valuation) from an extra unit of output is not meeting its cost (social cost) and is being (cross) subsidised. In the case of TMR services, this leads to a lower and an upper bound for prices as follows:

- *Lower bound*: Revenues from electricity generation are effectively applied to cross-subsidise reliability services when the average incremental revenue from reliability is insufficient to cover its average incremental costs;[27] and

27 Average incremental costs include "product-specific" fixed costs – that is, fixed costs incurred only on behalf of the product in question.

- *Upper bound*: In a market, competitive discipline is imposed on incumbent firms by the threat of entry. Thus the highest price for reliability that an incumbent could select is the efficient stand-alone cost of providing the service. In this instance, the efficient stand-alone cost is the lesser of the cost of appropriate transmission alternatives and a generation investment designed specifically and only to provide reliability services.

The claim by the AESO that providers of TMR should, as a general matter, recover all fixed costs in the energy market is therefore only economically efficient if no fixed costs are required for the provision of reliability services.[28] A provider of reliability services that could not recover these costs would exit a contestable market. Furthermore, there is no economic reason why costs that are common to energy and reliability should be entirely allocated to the energy market; indeed, in high-cost load pockets with a uniform electricity price, this practice may well be uneconomic.

At a minimum, it would seem that a provider of TMR services should be entitled to recover any additional (fixed) costs it has incurred to provide reliability services, for instance, additional locational costs or the costs of any additional equipment that may have been installed to provide the service.

We note also that where there is competition in a market for a homogeneous good that a single market price clears the market: there is no distinction in price between the costs of supply side operators. If the market is competitive then the price will be reflective of least cost supply and different operators will be earning different returns depending upon many things including the age and vintage of plant. For example, if the fuel of the price-setting generation at the margin is gas then, say hydro, plants that are lower cost produce rents: but it would be economically inefficient to suggest that the price of energy to hydro plants should be lowered. The opportunity cost of electricity consumed is set by the price of gas. This principle is widely applicable, including to energy vs. (energy) TMR in an unfettered market situation.

Value of Reliability

Taken on their own, the above pricing principles provide limited guidance for efficient pricing. In practice, the range of prices between incremental and stand-alone costs is often very wide, and this is almost certainly the case in this instance. But until now, the above discussion has been without reference to the demand for the jointly produced products, or the value derived from these. In a competitive market, demand and supply would determine the relative value and therefore prices of electricity and reliability, but due to the economics of transmission, consumers have no choice in the matter.

28 Para 40 (2), Alberta Electric System Operator Article 24 Amendment Application, August 16, 2004.

Instead, the AESO procures this service on their behalf. In fact, the situation here is precisely the opposite of the idealised 'perfect competition' among infinitely many traders, but more akin to a non-cooperative bargaining situation in the presence of specific, sunk, assets. While economic theory can help in predicting what agreement, if any, will be reached by the bargainers, it offers little help in answering questions such as what would constitute a reasonable agreement, or how a reasonable arbiter would settle the dispute.

One approach is therefore to look to competitive market outcomes as a guide to how reliability services would be priced. The relative value of jointly produced products varies according to the wider market environment. In some cases, the topology of the transmission network may be such that the reliability component of a generator's output is relatively unimportant in comparison with the value of the energy generated. In contrast, in the case of the Rainbow Lake Units, the reliability component of their output appears to be of material value to the AESO in meeting its statutory obligations to operate the network in a secure and reliable manner.

Cost of Service

Where it is deemed appropriate to employ a cost of service approach it should be assessed as providing, at a minimum, zero expected economic profit.[29] Although this is similar to cost of service within a centrally planned and fully regulated environment, it will entail some differences to account for the market environment, its process of change and risk sharing. This is a forward-looking concept where the firm bears uncertainty in demand for TMR and risk (or certainty in case where TMR is to be a stop gap until additional network is constructed) of stranding.

Wider Context

These are very difficult questions, and how they are resolved will have a wide-reaching impact on the prices that consumers can expect to pay for reliable electricity supplies. As such this is a politically charged debate:

- Supply side market participants would claim that consumers do not see the full cost of reliable service provision; while
- Representatives of consumers would point to market power that is undoubtedly also a concern in these types of situations.

29 Discounted from the future to the present, zero economic profit implies the firm earns revenue to cover all costs including a return on capital that just matches the return that could be earned elsewhere (i.e. opportunity cost of the capital invested).

In practice, a balance between these competing interests needs to be struck, and economic principles alone may not be the only appropriate guide. However, if a market electricity system is to be promoted, the debate in our view should be conducted in the context of dynamic efficiency, in which case the implications for the credibility of the regime, investment, risk management, and future prices and services should attract significant weight.

There is no single right answer in economics for how and over what time these allocations should be made, and there is therefore an element of discretion necessary to determine a tariff. This is an important role of the AEUB. We understand that the AESO has filed a proposal and that at the time of writing it is being considered by the AEUB.

4.4. Transparency Issues

A third major area of dispute appears to relate to the AESO's assessment that the provision of ancillary services is in some cases not competitive. These concerns appear to have precipitated AESO market intervention, both in terms of the conscription of certain ancillary services, but also and in terms of changes in generation dispatch. This appears to refer to two aspects of the Rainbow Lake dispute:

- The fact that for various reasons, the AESO appears to have found itself in a difficult negotiating position with a sole and aggressively profit-maximising supplier of TMR services; and

- The undesirable incentive properties of the Article 24 payment provisions referred to above. That is, the 'greater of' price methodology in Article 24 valued conscripted TMR service in excess of COS, removing the incentive for a sole to contract for TMR at anything less than the 'greater of' heads of the existing Article 24.

It will also be affected by the relatively high-cost of producing energy in that area and the grid expansion initiative which will limit further the interest of new entrants, and raise the cost of short term supply depending upon the operating status of existing plant.

4.5. Findings and Recommendations

4.5.1. Governance of the AESO

The EU Act and associated statutory instruments place a number of obligations on the AESO, and refer to various objectives, including the need for promoting the fair, efficient and openly competitive exchange of electric energy, but also to the public interest and concepts of prudence and reasonableness. These objectives need not conflict, and indeed it could be argued that:

- Competitive processes are fundamentally in the public interest; and
- The purpose of introducing reform and competition is to benefit customers and the wider public interest.

AESO Interpretation

However, it does appear that the particular interpretation that the AESO has placed on commercial aspects of these objectives is such that the concept of promoting efficiency, competitiveness and fairness of commercial outcomes has taken second place to the AESO's interpretation of what would be in the public interest – specifically the short-term financial interest of ratepayers. This is apparent from a number of communications with the AESO and also by the absence of a discussion about the overarching objectives for promoting fair, efficient and openly competitive arrangements in the AESO's submission to the AEUB in relation to the proposed Article 24 amendment. This view has also been put to us in the course of the review by a number of market participants, referred to in Section 3.4.

We do not believe it is appropriate to aim for black and white statements about how to balance competing objectives in all cases. To do so would run the risk of a rules bound market that is unresponsive to changing conditions or unexpected developments. Thus we believe that it is important that some discretion be available to the AESO. There appears to be a sufficient number of independent review mechanisms in the market involving formal and informal participant consultation, ministerial regulations and the function of the MSA to guide the AESO. Processes involving the AEUB during Tariff hearings and changes to the ISO Rules offer a formal, but lengthy, further opportunity for guidance. This current review by the MSA is a prime example of this process in action.

4.5.2. Delineation of Responsibilities

Lack of Competition

As a general rule, competitive processes are likely to deliver efficient outcomes. But there are also situations when competition is negligible, and where unfettered market forces can lead to inefficient and inequitable outcomes. This may have been the case in the Rainbow Lake context, where changed pricing provisions to support the deregulated Alberta market enabled generators to effectively withhold supply in the spot market in order to attract very significant revenues via TMR payments. The expansion in transmission that is likely to take place under the Transmission Development Policy will have the effect of reducing the number of instances where this type of market behaviour might be expected. But in the interim it limits competition and incentivises owners of plant that will be stranded to more aggressively pursue revenue.

The consequence seems to have been that in response the AESO adopted a range of increasingly heavy-handed quasi-regulatory measures to conscript TMR services and develop associated pricing provisions aimed at protecting customers. While the objective may have been creditable, the result was apparently in accord with the repeated bilateral monopoly game mentioned above. The approach adopted raises fundamental questions about the delineation of responsibilities and a potential conflict of interest. That is, the AESO increasingly found itself in a position where it would attempt to simultaneously act as market maker and commercial negotiator, and where its commercial negotiating positions may have impaired its role as an impartial market maker. Transparency of processes appears to have been compromised in the process, and we have noted with concern the poor regard in which market participants appear to hold this function of the AESO as a consequence of its action. This is unlikely to be conducive to a well-functioning electricity wholesale market.

Conflicts of Interest

In Section 3 we described how the potential pool of TMR providers may have been limited by the process that was adopted. As a result there may have historically been circumstances where the AESO could have been able to procure TMR services on a more competitive basis. In these cases, the concern is that prices paid by the AESO may have been ‘too high’, although there is clearly no way to determine this definitively.

But the way the AESO balances the range of its powers and objectives is key. While the AESO may have genuinely found itself in a very difficult position in the Rainbow Lake dispute, and genuinely believed it should accord high weight to cost minimisation, it would be difficult to argue that its conduct has been consistent with what we would understand is the overarching market or commercial objective of the EU Act – that is promotion of fairness, efficiency and competitiveness:

- There would seem to be a potential conflict of interest, if an ISO is required to define the services it needs to procure and simultaneously dictate the terms on which it will procure these;
- The AESO’s assessment of what constitutes reasonable and prudent payment for TMR services appears to be based on short–term cost minimisation objectives, rather than on an even-handed or rigorous analysis and its wider promotional role;[30] and

30 We note anecdotal evidence from market participants in relation to the AESO’s apparent eagerness to pursue liquidated damages from market participants.

- While we tend to concur with the AESO's assessment that certain suppliers of TMR can be considered to be virtual monopolists, measures such as changes to the dispatch order in the midst of a dispute and when negotiations are still afoot is at best inflammatory in the context of a competitive process, regardless of whether the objective was cost minimisation under the AESO's interpretation of a cost minimisation objective.

Regulatory versus Operational/Commercial Responsibilities

In the short term, the risk is that such practices undermine incentives for the private sector to provide TMR-type network support services. In the longer term, these policies risk undermining investment incentives and the operations of the Alberta wholesale market, to the detriment of all stakeholders, including customers.

But given that the new transmission policy is aimed at effectively eliminating the need for TMR services, this particular aspect of the AESO's objectives may no longer be a concern going forward. Nonetheless, we consider that these types of governance issues represent material risks whose effect may extend beyond their immediate impact on TMR service provision.

It would therefore seem to be vital that concerns about non-competitive market outcomes should be addressed by the appropriate regulatory body – the MSA – rather than indirectly via operational and commercial decisions taken by the AESO.

4.5.3. Transparency and Regulatory Scrutiny of the AESO

Section 3.4 noted anecdotal comment from market participants to suggest that the network planning process and in particular TMR acquisition over a number of years may not have occurred in a timely and robust manner. Contradictory statements by the AESO about the urgency of certain requests would seem to support this criticism.

Information Provision Requirements

It is crucial to a robust competitive environment that planning and investment processes occur in a timely and credible manner. Subject to the clarification we have sought about the future role of TMR, under the Transmission Regulation, it appears generators will increasingly be prevented from offering economic alternatives to transmission under commercial terms and conditions, except in overwhelmingly uneconomic circumstances. However, our understanding of the MSA's discussions with market participants and with the AESO, would suggest that participants remain at risk of being conscripted for TMR service in circumstances where network planning and investment processes have not kept pace with growth of the market.

This would suggest a need for publicly documented planning objectives related to TMR specifically. These requirements have already been incorporated within the Transmission Regulation, although it is not clear to us whether corresponding oversight processes are in place.

Asymmetry of Risks

At the same time, the ability of the AESO to conscript units when its own transmission planning and commissioning processes are proven by circumstances to have not been adequate, would seem to us to constitute a clear case of moral hazard. This is a possibility even when those planning and commissioning activities were at the time in accord with best practice. The resultant risk allocation is similar to that of a central planning regime from the perspective of the AESO, but not for generators. In effect, the AESO is in a position to postpone (or similarly bias) expenditures that would eventually have to be borne by ratepayers by conscripting units, and if amendments to Article 24 are implemented, at a relatively low cost. By implication, the cost consequences of such delays would be borne by generators. We therefore consider that a clear delineation of the circumstances when such conscription would be appropriate in the first place is required.

4.5.4. Efficient and Openly Competitive Processes

Where the multiple roles of the AESO create internal conflicts, there should be greater transparency and clarity of objectives and processes in relation to how the AESO should resolve such conflicts.

Demonstrably Non-competitive Situations

Clarification of the right of the AESO to justifiably terminate commercial negotiations and resort to reliance on its powers of coercion in order to maintain reliability is another important measure that will improve the competitive environment. This has been a matter left to the discretion of AESO and is at the heart of the AESO’s applications for amendment of Article 24 of the ISO Rules. Disagreement over this point has been present for a number of years and resulted in extended disputation.

We consider that clarification of these boundaries will provide the ISO and participants with clearer guidelines and compliance measures. It will also mean that the negotiating stance of the ISO is far more robust and defensible, and that negotiating processes are ‘bounded’. There would also seem to be a clear role for the MSA in over-seeing or assisting the ISO in terms of identifying situations where a competitive outcome is unlikely to arise.

Requests for Proposals

In addition it appears that the roles for the ISO as market maker, promoting fair and openly competitive outcomes has conflicted with its pursuit of the most commercially beneficial outcome to bilateral negotiations for TMR services on behalf of its constituency. These roles also represent a significant moral hazard for the ISO. Improvements in each of these would enhance the competitive nature and providing they were not overdone, for example to the point where transaction costs become exorbitant, offer the opportunity for better prices for the services. Although we acknowledge it is of course not possible to prove this in hindsight.

Regulatory Scrutiny of Pricing Guidelines

We have noted that the recent changes to the EU Act and the Transmission Regulation have resulted in a clearer governance environment for the ISO and have increased the level of transparency required of it in its transmission development activities. We expect that these will contribute to the AESO adopting processes that are more 'competition friendly' than have been used in the past and assist in resolving the apparent fundamental lack of agreement about the nature of payments and the service that TMR provides and hence the philosophy that should guide the calculation of remuneration to providers.

However, a final area of clarification relates to the pricing methodology that should be adopted in relation to TMR services. It would seem to us that a fair and economically justifiable outcome would imply that:

- Prices paid for TMR services should at a minimum reflect a reasonable estimate of the incremental costs associated with providing TMR services, including fixed costs components and a reasonable rates return, where fixed costs are amortised on a realistic basis given the market evolution; and

- Prices paid to existing TMR providers should be determined on the same principles as prices paid to TMR providers who have not yet committed to irreversible investment decisions.

Proxy Plant Concept

We are aware the concept of 'proxy plant' pricing has been considered in AEUB hearings.[31] We would hesitate to suggest widespread use of a proxy plant concept as this is inconsistent with our belief that the field of competition can be broadened if need for TMR is defined more in terms of the technical capability rather than the characteristics of the likely plant that will provide the service.

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31 The concept involves pricing based on the parameters of typical plant being available as a default or typical price that can be paid to any plant that is conscripted.

Furthermore, the application of this concept still requires decisions to be taken about such critical factors as potential stranding; these are decisions taken by parties not exposed to the concomitant risks. We have therefore not pursued this concept.[32] We also note that the AESO has also advised against the use of the proxy plant concept since it considered that:[33]

- The existing baseline compensation options under Article 24 are excessive, and the addition of a proxy unit payment option in the existing 'greater of' options would add to this excessive compensation baseline and possibly give incentives for perverse offer behaviour and over-reward efficient generating units;

- A review of practices in other jurisdictions found only one example of proxy unit use; and

- Compensation of Going Forward Costs would be more consistent with the AESO's negotiated contracts and appeared to be consistent with the direction in other jurisdictions.

However we understand the AESO retains an expectation of a considerably narrower range of plant to meet TMR requirements than we do.

An advantage of our recommendation in Section 3.5.3 to require explicitly that the combination of physical network and contracted TMR is designed to avoid the need for conscription during dispatch for other than unexpected events, is that it will remove much of the commercial contention and economic complexity from the calculation of compensation. This is because its commercial significance will be much reduced and the conscription will be for the short-term and not repeated and thus reduce the period of time over which there would be a need to remunerate an investor.

The wider package of recommendations does, however, include provision for conscription into contract in transitional cases where there is no alternative, for example when time has expired for alternative providers to enter the market for TMR or for transmission substitutes to be constructed. We consider that the circumstances where this may occur will require case-by-case consideration with a high level of regulatory input.

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32 Parallels between the proxy plant approach and TSLRIC telecommunications pricing suggest themselves: the heightened prospect of stranding would augment the problems that have been identified with the TSLRIC mechanism.

33 Alberta Electric System Operator, Article 24 Amendment Application, August 16, 2004. Para 57

This is evidenced by the long history of the situation in the Rainbow Lake area where there have been formal and informal undertakings by market authorities and participants, one-off compensation decisions by the AEUB and changes to planning policy in relation to the likelihood of transmission augmentation. Accordingly this option is included as a backstop in our recommended procurement process, but not as a prime competitive element.

4.5.5. Clarification of Objectives

While we, as we assume many others would also, have some sympathy for the AESO's intentions in relation to cost to ratepayers, the EU Act gives the ISO a clear duty in relation to promotion of competitive outcomes. This does not necessarily equate to proactively pursuing the lowest short-term cost for the consumer. It requires a balanced approach to reconciling the opposing interests of <u>all</u> stakeholders, including market participants and consumers, and the evolution of the market and, in our view, with particular reference to dynamic efficiency. If the market rules are adequate, the outcome of a robustly fair and openly competitive market will also be efficient and thus at lowest long term cost for consumers.

It should also be open to an ISO to seek a change to the Tariff if it considers it appropriate and within its charter, as the AESO is currently doing in its application to amend Article 24 of the Tariff. We note a fortunate but somewhat arbitrary element of the governance arrangements in the Alberta market whereby energy market prices are determined by the ISO Rules established by the ISO, and compensation for TMR operation out of merit or under conscription is determined in the Tariff approved by the AEUB. Had the TMR payments been determined in the Rules, as is the case in some other markets, there would have been a further hazard for the ISO as it would have been the network planner, TMR negotiator and the body that decided the compensation under conscription.

Given that the interpretation of legislative principles appears to be fundamental to the operations of the Alberta wholesale market and, within that market, to the role of the ISO within the governance structure, it would seem imperative that the responsibilities of the ISO should be clarified.

We consider that a clearer statement of how the ISO should balance its duties should focus on:

- *Establishing clear and transparent boundaries between energy and TMR services for the functioning of the market that ensure reliability and security of supply to agreed performance standards*: In particular this would require the planning function to fully procure all necessary transmission and, where appropriate, TMR contracts as part of its planning function to meet reliability standards. This would include:
    - Responsibility for taking a forward looking approach reflected in the amount and various terms of contracts; and

- A prohibition on planned reliance on non-market powers of short-term operational conscription, either at the time of planning or subsequently;

- *Limiting powers of conscription in the interests of reliability to an (important) 'backstop' to the market in extreme unpredictable circumstances, essentially those of force majeure*: The ISO should be required to take all reasonable measures to avoid their use. This is an important mechanism to separate the planning, commercial and reliability functions of the ISO. Specifically the case of non-renewal of TMR contracts in the Rainbow Lake area, the known replacement by operational conscription would represent a breach of our proposed responsibilities for the planning and commercial functions. Enforced medium-term contracting, providing it is supervised by a separate body (presumably the AEUB) should be allowed for in the event of failure of commercial contracting arrangements where there is no physical alternative. This would be a last resort and be recognised as a failing of the market design and be accompanied by a review of the design in this regard.

Within those bounds, the overall ISO function should be required to conduct, and demonstrate promotion of, fair and openly competitive processes wherever possible. The ISO should also be able to be challenged on the manner in which it implements its duties.

4.5.6. Monitoring and Reporting

In this broader framework it would be important that a body is charged with assessing the success of both the rules and the performance of the market institutions in achieving the objectives of the market. A standing requirement for regular and independent review, potentially by the MSA, would seem appropriate. An objective of such a review would be to critically review all instances of conscription and assess if they were within the intent of a backstop. We would expect that at the time conscription occurs, there will be very limited opportunity to avoid it, especially if it is operational conscription during the dispatch process. Although the review should assess if this is correct, the focus should be to consider if conscription was necessary because of:

- A problem with the market design;

- Lack of information to the market or implementation of planning arrangements, and how this could be improved, for example by amending the arrangements for forecasting of demand for planning studies on which network investment decisions were based; or

- The market conditions were outside the bounds of the technical requirements for planning and operational standards and the ability to conscript avoided a power system emergency. This is very similar in concept to the planning for operational contingencies where ancillary services are carried for credible events, but not for extreme or multiple events.

Only the last reason would satisfy a test of conscription as a backstop to commercial arrangements.

The review should be independent of the ISO function and be published to the market. A conclusion that the market design was inadequate should clearly be addressed by a change to the Rules or Tariff as appropriate. Such a finding should not be regarded automatically as a failing, but potentially as a signal that it is time for an evolutionary change. The risk of adverse finding about the Rules acts as an incentive for the ISO to ensure that the Rules are at all times well accepted and endorsed as far as practicable, by all relevant stakeholders, further aiding the promotion of a competitive market. A conclusion that the existing Rules or procedures had not been implemented adequately would reflect on the ISO and be a matter on which the Board of the ISO should be required to respond. This would be similar to a qualification in a financial audit that might call for improvements in any company. In extreme, and we would expect unlikely, situations, Ministerial intervention through the power to make Regulations would provide a final recourse.

5. REVIEW OF INTERNATIONAL TMR ARRANGEMENTS

This section provides a review of arrangements for TMR in a selection of other markets. TMR is variously labelled Reliability Must Run (RMR), Network Support and System Support elsewhere. The type of service we are considering here as TMR is generally dispatchable and excludes most fast acting reserves, which are more likely to be priced dynamically alongside energy. Appendix E to this report provides further of TMR arrangements reviewed. Figure 3 summarises these findings.

In summary, TMR arrangements differ between wholesale markets, and appear to reflect key market design characteristics, as well as historical arrangements:

- *Reliance on contracts versus spot market arrangements*: With the exception of PJM and NEPOOL, TMR services are procured via contractual arrangements. PJM relies entirely on capped spot market prices to compensate TMR service providers, while NEPOOL employs both contracts and spot market pricing mechanisms. Spot market pricing mechanisms have been considered for the Australian National Electricity Market (NEM) but not implemented to date;

- *Responsibility for RMR contract negotiations*: Generally the market ISO procures TMR. In Australia the National Electricity Market (NEM) covers a very wide geographic area spanning approximately 4500km of the eastern and southern states. Arrangements that impact the market are generally procured by NEMMCO, the NEM ISO, and network support agreements are also negotiated by transmission network service providers (TNSPs) as part of their obligation to ensure reliable localised network operations;

- *Remuneration for TMR services*: Payment arrangements vary widely, including in relation to whether fixed costs may be included. Agreed fixed costs may be included in Ontario, while locational marginal pricing markets such as PJM and NEPOOL focus on variable cost payment mechanisms. However, in the US the Federal Energy Regulatory Commission (FERC) has requested a review of compensation arrangements for frequently constrained resources. In the California wholesale market, TMR generators must elect to either participate in market transactions and retain all corresponding revenues or effectively operate under cost-of-service regulation. TMR providers in the Electric Reliability Council Of Texas (ERCOT) may sell excess power into the balancing market and retain a portion of profits; and

- *Reliance on competitive tenders versus bilateral negotiations*: In Ontario, competitive RFPs are the preferred option, otherwise the Independent Electricity Market Operator enters into negotiations with individual suppliers, and a standard, cost-based agreement as a last resort. In the case of PJM, FERC recently supported ISO administered auctions/ RFPs for longer-term agreements. ERCOT is also considering issuing competitive RFPs for 'Must Run Alternatives' (MRAs). In the Australian NEM, a combination of competitive tenders and negotiation is employed. TNSPs are required to publicise identified network opportunities for market participants as part of their annual planning statements.

Figure 3: Overview of selected international TMR/RMR arrangements

Market	Energy pricing framework	Network support arrangements	Governance/oversight	Information /tendering requirements	Pricing arrangements
National Electricity Market (NEM)	Regional (zonal) market with inter-regional price separation (note market stretches across 4,500km)	Network support services that impact the market are procured by the NEM ISO (NEMMCO). As part of their obligation to ensure reliable localised network operations, transmission network service providers (TNSPs) must seek cost-effective solutions to address intra-regional network constraints. Options include network support contracts with generation resources or demand side options.	Regulatory oversight of prudent expenditure will become the responsibility of the Australian Energy Regulator and is currently a responsibility of Competition Regulator. The National Electricity Code places general obligations on TNSPs in relation to planning and information provision processes, the conduct of negotiations.	Identified network support requirements are published via annual planning statements and invitations to participants to submit proposals.	Commercial terms of individual network support agreements (equivalent to TMR) are confidential although total ISO expenditure on contracts is published. Spot price is marginal price derived from LP inclusive of effect of network support contract. No market mitigation is employed in dispatch timeframe. More 'market-oriented' constraint support pricing options are under review but not yet endorsed. These would result in local adjustments to spot price to reflect whether a specific generator alleviated or contributed to a constraint.

Market	Energy pricing framework	Network support arrangements	Governance/oversight	Information /tendering requirements	Pricing arrangements
Ontario Wholesale Market	Hourly Ontario Energy Price for energy across Ontario Separate prices at twelve intertie zones with neighbouring markets	The Independent Electricity Market Operator (IMO) may enter into 'reliability must-run' (RMR) contracts with participants to maintain network reliability, or if existing facilities become unavailable. RMR may be provided by generation and demand resources.	Oversight by the Ontario Energy Board (OEB)	Where practical, competitive RFPs are adopted, otherwise negotiations with individual suppliers. Where processes are deemed not to achieve a fair and efficient outcome the IMO will put in place a standard, cost-based agreement.	Standard contract provides for: – Agreed fixed costs; – Variable hourly costs; – Variable energy costs.
Electric Reliability Council Of Texas (ERCOT)	Locational marginal pricing for generation resources Zonal pricing for loads	RMR units are operated under the terms of an annual agreement with ERCOT.	RMR agreements are in a standard form and do not require additional approval from the ERCOT Board of Directors or from any regulatory body. ISO Staff are required to develop a list of 'exit strategies' for each RMR contract.	Work is in progress to define procedures for contracting with 'Must Run Alternatives' (MRAs). ERCOT would issue competitive RFPs for MRAs, compensation would be case specific, and approved by ERCOT staff, with input from Stakeholder Committees.	– Variable operating cost; – Plus a 10% 'adder' on non-fuel costs. Excess power may be sold into the balancing market, and the unit may retain a portion of profits.

Market	Energy pricing framework	Network support arrangements	Governance/oversight	Information /tendering requirements	Pricing arrangements
Pennsylvania-New Jersey-Maryland Interconnection (PJM)	Locational marginal pricing	There are currently no "Must-Run" for Reliability contracts. PJM selects RMR units on a daily basis whenever it finds that a unit is required to maintain reliability. A unit may be selected for RMR services and cost-capped at any time.	Oversight by the Federal Energy Regulatory Commission (FERC). In reviewing PJM's RMR arrangements, FERC: – Found the PJM tariff failed to resolve disputes relating to compensation for RMR units; – Directed that unresolved disputes should be brought before FERC.	FERC said that in the absence of market design changes, RTO/ISO administered auctions/ RFPs to create a long term commitment or generator specific contracts may be appropriate. FERC also: – Ordered rules to be developed for a clear trigger authorising the RTO/ ISO to act; – Required processes resulting in the auctions/ RFPs to be transparent with material stakeholder input.	RMR units are offer capped as follows: – Weighted-average LMP when the RMR resource was operating in merit and the price was deemed to be competitive – Incremental operating cost of the generation resource, plus 10% – An amount determined by agreement. FERC directed PJM to enable frequently mitigated units needed for reliability (> 80%) to receive higher offer caps or alternative compensation.

Market	Energy pricing framework	Network support arrangements	Governance/oversight	Information /tendering requirements	Pricing arrangements
New England Power Pool (NEPOOL)	Locational marginal prices for generators Zonal prices for each load zone	Daily RMR Resources are required on a daily basis as necessary for the provision of operating reserve requirements and adherence to reliability criteria. Generation resources in Designated Congestion Areas (DCAs) may apply for an RMR agreement (pro forma contract). NEISO can also enter into cost of service agreements if the ISO has determined that it requires a particular facility to stay in service for reliability reasons.	FERC	NEISO will select and daily RMR resources on a not unduly discriminatory basis in accordance defined procedures.	For daily RMR resources, payment is the highest of: – The LMP for the hour; – The lower of the supply offer or the applicable reference level; or – The resource's stipulated bid cost. Under the RMR pro forma contract, entities can be paid prospectively under four options, depending on the type of generator and the purpose of the RMR contract. Peaking Unit Safe Harbor (PUSH) offer rules allow owners of low capacity-factor units (less than 10%

Market	Energy pricing framework	Network support arrangements	Governance/oversight	Information /tendering requirements	Pricing arrangements
					annual capacity factor) to include fixed costs in their supply offers.
California Wholesale Market	Zonal	To mitigate local market power, the CAISO relies on RMR contracts with units located at known congested locations on the transmission grid.	The CAISO undertakes an annual planning process to designate specific generating units as RMR, for approval by the CAISO Governing Board. Rates are authorised by FERC or the local regulatory authority. whichever authority is applicable	Local Area Reliability (LARS) processes included a solicitation of proposals for load management alternatives, transmission projects and generation resources to meet forecast reliability requirements.	RMR units must elect to provide service under one of two 'conditions': – A Unit under Condition 1 may participate in market transactions and retain all corresponding revenues; – A Unit under Condition 2 is dispatched by the CAISO and may not retain revenues from market transactions.

6. SUMMARY OF FINDINGS AND RECOMMENDATIONS

This section brings together the findings about technical, commercial and governance issues that we have developed in previous sections of this report and presents a consolidated package of options for the future.

In a disaggregated electric power industry a range of agencies determine processes, and manage and oversee operations. In Alberta the key entities are the government through relevant statutes, the Minister through the issue of Regulations, the AESO Board and Management, the AEUB and the MSA through its oversight of compliance role. The market design is determined by the combined effect of the actions all of these.

Our focus in this report is on the operation of TMR and in particular whether overall the outcomes have been consistent with *promoting a fair, efficient and openly competitive* market and the extent to which changes can be made to better meet this objective. In considering options for change to any element of the design it is important to ensure that the change is a net improvement to the overall design. We are also aware that there will be practical limits to the extent that changes can realistically be made, and key market characteristics, such as the use of a single market-clearing price for energy in the spot market and the roles and responsibilities of the key entities are 'given' for this assignment.

Therefore, the options for improvement presented in this chapter involve changes to individual elements of the design and affect the interaction between them but do not involve fundamental change to the market design. Changes to some elements are subtle and will involve only a change in emphasis, for example in the assessment of technical needs and greater transparency. Changes to the commercial procurement process will be more significant, and realising the full potential benefits of such changes will involve a number of the agencies, including the clarification of policy intent by government and the AEUB.

Finally, although the changes will, we believe, improve the potential for the market to function better, this will only occur if market participants also work within the arrangements and accept unavoidable imperfections that may be present. Although a regulatory safety net in the event of market failure is included, there is scope for gamesmanship on the part of participants during the initial phases that will force the process to a regulated and hence non-market outcome more rapidly than necessary. In that respect the market will "get the market it deserves".

6.1. FINDINGS

6.1.1. Scope for Competitive Supply

Our review of TMR processes first considered how the technical (engineering) analysis that defines the need for TMR is translated into the TMR procurement processes and subsequent agreements. As a general matter, the scope for competitive supply of TMR services depends on the precise nature of the technical requirement and needs to be assessed on a case-by-case basis. In some regions of Alberta there may for all practical purposes only be one or two parties able to supply additional TMR, and if the Transmission Development Policy is implemented as planned, the prospect of attracting new competitors is likely to decline. This sets the context for a situation in which a monopsony buyer, the ISO, must reach agreement with a monopoly seller (or a very limited number of potential suppliers). These parties are driven by different, and in the case of the ISO, conflicting, objectives. To ensure that the eventual outcomes of such processes are consistent with the wider objectives of the EU Act, a framework of additional ‘rules’ will be required.

6.1.2. Competitiveness of Procurement Processes

Turning first to the ISO function, we found that in choosing appropriate procurement processes, the AESO has not sufficiently pursued opportunities to increase the potential pool of suppliers to enhance competitive processes, but tended to focus instead on ‘preferred’ suppliers identified early on. This conclusion reflects our understanding of:

- The technical needs identification, which sometimes appears to have adopted an overly narrow focus;
- The choice of procurement processes, for instance as reflected in a preference for bilateral negotiations; and
- The timeliness with which these processes were undertaken.

6.1.3. Governance of the AESO

Our findings should be interpreted in the light of the wider governance framework that applies to the Alberta wholesale market. The EU Act and associated statutory instruments place a number of obligations on the ISO function, and refer to various objectives, including the need for promoting the fair, efficient and openly competitive exchange of electric energy, but also to the public interest and concepts of prudence and reasonableness.

The EU Act is structured in a manner that we consider requires the ISO to balance competing objectives, and we have concluded that the AESO has placed the greater emphasis on its interpretation of the public interest – specifically the short-term financial interest of ratepayers – than its duty to promote a competitive outcome. This would have contributed to the difficulties in undertaking the multiple functions that are part of its duties and responsibilities, each of which are complex in their own right. While some market participants may in turn have legitimate grounds for complaint, it also appears that others may have elected aggressively to pursue their own commercial interests, fuelling increasingly adversarial processes.

To summarise, we then found the AESO adopted a range of increasingly heavy-handed quasi-regulatory measures to conscript TMR services and develop associated pricing provisions aimed at protecting ratepayers. This raises questions about:

- The transparency of procurement and wider market processes, given the limitations on TMR processes and the apparent willingness of the AESO to modify market dispatch operations in pursuit of short-term cost minimisation but at the risk of degrading the long-term market environment;
- The potential for conflicts of interest, if the AESO can define the services it needs to procure and simultaneously dictate the terms on which it will procure these, in a manner that effectively uses a quasi-regulatory power of conscription contemporaneously with a commercial negotiation process;
- The basis on which TMR payments are determined, given the AESO's assessment of what constitutes reasonable and prudent payment; and
- The degree of scrutiny of how the AESO fulfils its functions, given that there is some indication that participants are at risk of being conscripted for TMR service in circumstances where network planning and investment processes have not occurred in a timely manner.

6.2. Options for future Pricing and Processes

These findings are reflected in the following recommendations.

6.2.1. Competition Boundaries

Within an environment where all opportunities to broaden the field for competition have been taken, we would see a hierarchy of procurement approaches, including:

- Fully competitive RFPs;
- Parallel bilateral negotiations;

- Regulated bilateral contracts by agreement; and
- Mandated bilateral contracts.

These options may progressively apply to a lower level of competition in the usual sense of the word, but should in each instance retain competitive tension between and, where feasible, among stakeholders. In the traditional sense, this tension will be between and amongst buyers and sellers, and where there is a strong regulatory involvement there should be a tension between the regulatory and competitive processes.

In circumstances where an auction can be conducted, for example through an RFP, these principles might be used to set upper and lower bounds on the price that would be accepted by the ISO. However, because of the specificity of TMR and in particular where there is limited competition, some form of negotiation or regulated arrangement will be needed to finalise arrangements.

As a last resort, where there is severely limited competition or it is appropriate to employ a transitional arrangement, some regulation may be needed. If so, it should be regulation set by an authority distinct from the ISO, and which transparently binds the ISO and participants. In these circumstances it will be necessary to provide more guidance for the ISO in order to avoid risk of further disputation, albeit within a narrower range.

6.2.2. Framework For Enhanced Competitive Process

The design of the different forms of acquisition process and the boundary between circumstances where each should be employed are both important. The following describes a general framework for each form. This would require the ISO to amend some aspects of its current practices and refine others. The key points we recommend are:

- Bilateral negotiation should not be the first recourse of the ISO, but it should be recognised that this will be necessary in some cases;
- Competitive processes, including RFPs, and where possible auction-type mechanisms, are most likely to elicit competitive responses; and
- Given the nature of technologies likely to be able to provide the broad TMR service, TMR should be defined as a more diversified service than simply MW generation or MVAR capability (see section 3.4). The statement of TMR need should concentrate on the problem rather than a perceived solution. There is in fact an advantage in purchasing TMR service from technologies that have the least impact on the energy market and potentially these could be favoured although we would expect their supply to be reflected in their bid prices.

Complex case-by-case analysis and market soundings of the potential for competitive level of response could be developed for each situation. However, we doubt that the transaction cost for the relatively infrequent and limited part of the market will warrant this. A framework along the following lines could be considered. It has a number of sequential steps, although not all will apply in every case, in particular if time is short and there is no alternative but to use an arbitrated or regulatory approach. This is unavoidable and reflects a reality of life in competitive environments and the shorter the time, the more it will be necessary to pre-empt competitive arrangements, for example by negotiating only with parties identified by the buyer. The framework takes account of the interactions between the elements of the governance arrangements in particular the balance between prundency and promotion of competition. The framework is as follows:

- As part of the longer term planning process, potential applications of TMR should be identified well in advance as part of the annual 10-year plan. A non-binding expression of interest (EOI) should be published to elicit the level of likely response to a competitive process for TMR to guide and justify choice of formal acquisition process (e.g.. auction, negotiation etc). Where there are statutory limits or principles that will limit the price that will be paid these should be advised at the time. (Section 4.3.4 outlines that the Transmission Development Policy has established high-level bounds for the price but, as noted, the detailed interpretation of the treatment of fixed costs has not yet been finalised);

- The EOI could explore the potential for different length contracts to optimise value to both sides;

- The ISO should then engage in a competitive process drawing on procurement, auction and contract negotiation principles and reflecting the locational, and other dimensions of the particular TMR service required within any standard guidelines about price or terms and conditions. In doing so the following points should be taken into account;

    - Wherever feasible (thresholds to be provided suitable for the final process adopted) the ISO should conduct an open competitive process, e.g. an RFP;

    - The length of contracts should reflect the characteristics of TMR being sought;[34]

    - Competitive processes (as with auctions) should be designed to elicit information about possibilities and potentialities;

34 We note that for the transitional period to an expanded network it may well be economically efficient to re-consider the timing of network expansions in those locations where TMR is presently addressing congestion, and thereby impart flexibility n-1 TMR (transitional) contracting.

- Frequency of repetition of auctions (tenders) and their form (sealed bid, open outcry) will affect collusion potentialities; and

- Transactions cost should be optimised.

If responses to the EOI indicate a broad tender process would not be appropriate, the ISO should then commence bilateral discussion with each of the parties who had indicated interest in the EOI and take account of the following:

- At anytime the parties may <u>agree</u> to:

  - Conclude a contract, this would (obviously) be the preferred outcome; or

  - Enter into binding, but bounded, commercial arbitration.

  The arbitration should be bounded by any limitations imposed on the ISO by statutory or regulatory instruments and also by any prudency limitations, but these should be formally set by the Board of the ISO exercising its statutory. duty This is intended to enhance and demonstrate transparency and robustness of the exercise of obligations placed on and available to the ISO in this regard.

- For a limited period after a specified time during which the parties may negotiate, a potential provider of TMR may exercise an option to require that the ISO enter into the same bounded commercial arbitration.

  This is a deliberately one-sided option as this step sits at the boundary between competitive and regulated arrangements. The bounded arbitration limits the price to no more than the amount that the ISO had been prepared to accept within its duly established statutory limits and the potential provider would not exercise the option unless it was prepared to settle within the bounds. The ISO, on the other hand, retains a right to initiate a full regulatory determination, in the final step, in the event that insufficient TMR can be contracted commercially.

6.2.3. Framework for Managing Disputes and Regulatory Intervention

If there are insufficient suppliers prepared to reach agreement or commit to arbitration to meet the technical requirements set by the ISO, the process should move to a second stage. Here the ISO should advise the AEUB that it has been unable to secure sufficient resources to ensure reliability of supply and hence that the negotiation process (within the limits of the standard terms and conditions) has failed. The ISO should not participate in decision making to resolve the position from this point (but may provide assistance to AEUB actions). Resolution should pass to either the AEUB or an independent arbitrator, but assuming it is the AEUB, it should determine to:

- Direct the ISO to reissue the tender with amended terms and conditions (for example an extended term that may improve the commercial viability of an existing party offering TMR or attract a green-field entrant);

- Direct a nominated participant (including from amongst parties who have not participated in the earlier stages) to enter a contract on amended terms and conditions set through arbitration.[35] This would clearly be limited by the authority of the AEUB; or

- Authorise the ISO to construct transmission facilities or alter the timing of future proposals that it had previously discounted in favour of TMR. Clearly this would only be applicable in cases where it was physically possible to do so in the time available.

Any arrangement directed by the AEUB should be determined on a case-by-case basis in the face of transaction failure, and be regarded as transitionary. In time,new transmission may be built in accord with the Policy or a long term TMR arrangement may be put in place, providing a counter-balance to possible monopoly power of sellers. But this will require a clarification of the circumstances when TMR may be approved within the framework of the Policy.

While the Policy requires that the price for TMR is to be no more that the regulated alternative, by itself this should not be a simple comparison with regulated cost (be it network or TMR), given the difference in risk sharing between regulated and market environments discussed in Section 4.3.4. In the transition to the new Policy, if for whatever reason, transmission has not been built, but TMR contracting is constrained in accordance with standard terms and conditions, no TMR contracts may be forthcoming. This would potentially imply that the standard terms and conditions are un-commercial in the circumstances.

Mandatory contracting is likely to be very contentious and it must be presented as a last resort. It is conceptually analogous to the operational conscription that exists now, but is preferred on a least-worse basis as there is greater certainty about operating requirements and price. It also shifts the “non-market” intervention out of the dispatch timeframe into the planning arena and this is desirable for the certainty it affords the market place and hence enhances the fairness of the market place.

We have not conducted a review of the administrative authority of the AEUB in this regard, but we are aware that the power to conscript during dispatch is typically available to ISO’s as an emergency power system operation provision and may not be within the current scope of the AEUB’s authority. If this is the case then it may be necessary to amend its authority or other detail of the implementation.

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35 If this is outside the authority of the AEUB then there is little alternative but to allow the AESO to plan for as needed short -term conscription of TMR.

The recommendation also may seem to have a downside that conscription may in the end be for TMR that is not utilised, but it needs to be recognised that this step is only taken if it had previously been determined that TMR was to be contracted and it is essential to have arrangements in place *ex ante*, to provide certainty of supply.

Ideally the AEUB as the body that approves the rules for TMR compensation within the Tariff should be at arms length from any arbitration, but it also has multiple roles and is the body that approves the Transmission Tariff. Decisions at this stage of the process are heavily policy related rather than commercial, and hence we have opted to place the decision with the AEUB.

6.2.4. Pricing Principles

As noted earlier, at the time of writing we understand that the AESO has filed a proposal for a network tariff to compensate conscripted TMR providers but the AEUB is yet to determine what the tariff should be. As discussed in section 4.3.4, there is no single right answer for the appropriate level of compensation from an economic perspective. But it is key to the workability of the procurement process without predisposing resort to the second mandatory stage described in this section. The more the tariff and standard principles can accommodate situations where TMR suppliers will not be viable in the energy market and are, for a period at least, genuinely substituting for network investment in meeting the reliability requirements on a planning basis, the greater the probability that the ISO and suppliers can reach agreement without recourse to arbitration or regulation. We reiterate a point made in the discussion of economic principles that the central planning approach to cost of service calculations is unlikely to be adequate, especially if a material proportion of fixed costs are expected to be recovered through the energy market. Nonetheless, there is such scope for the pricing principles that may eventually be adopted, that the ones chosen will almost certainly be controversial and subject to challenge by market participants.

We also reiterate that the Policy for the network will ultimately reduce demand for TMR and increase accessibility to the market for any suppliers, particularly those in formerly congested regions. In this circumstance we expect more competition for a smaller amount of TMR and the cost of TMR to fall, in which case the ISO’s procurement should not require all the steps of the process. However, in the transitional period, reduced competition for TMR and stranded assets are in prospect, enhancing the dominant positions of suppliers in certain regions. In this case the full process may well be used. This may benefit from flexibility in transitional pricing rules that have some acknowledgement of stranding and flexibility in the timing of network augmentation.

APPENDIX A: TERMS OF REFERENCE

Scope

1. Assess the competitiveness of the market for transmission must run (TMR) ancillary services.
2. Review and compare treatment of TMR in other jurisdictions.
3. Review of existing contracts for ancillary services other than operating reserves.
4. Review operating policies and system operation in the Rainbow Lake area.
5. Develop options for resolving issues.

Issues to be Addressed

1. Competitive Market for TMR Services
    a. What are the minimum conditions for a competitive market in TMR ancillary services?
    b. Does a competitive market exist for TMR services in this part of the province? The analysis should:
        i. Consider the "temporal" dimension. In the short term a competitive market may not exist; however, in the longer term, a competitive market may develop due to factors such as an increase in the number of competitors, transmission alternatives, etc; and
        ii. Take account of the ISO as the single buyer and potential for multiple sellers.
    c. Are either of the parties to the current dispute behaving in a manner which is inconsistent with a "fair, efficient, and openly competitive" market?
        i. A critical component of the project is to examine the behaviour of both parties over time to determine if they have behaved in a rational manner; and
        ii. A factor to consider is the relationship between the AESO's procurement activities and its operational authority to manage the grid.
    d. What are the constraints to a competitive market including but not limited to legislative/regulatory issues, operational problems, and market power?

i. Will the Alberta Government's new transmission policy/regulation impact a competitive solution?

e. Given the constraints (noted in clause 1.d. above), what are the possible options for creating or simulating a competitive market?

f. What are the benchmarks/key factors for success to evaluate future outcomes?

i. Comparison to other jurisdictions; and

ii. Other.

g. What are the alternatives to a competitive market?

i. Assessment is to include:

1. Proxy plant proposal;

2. Proposed AESO costing methodology; and

3. Transmission regulation cost cap.

2. Other Jurisdictions (Initial review to be conducted by the MSA. Information to be provided to CRA on an "all care no responsibility basis.")

a. Review and compare TMR in other jurisdictions.

i. Market design;

ii. Determination of value; and

iii. Dispute resolution.

3. Existing Ancillary Service Contracts (Excluding operating reserves). (Initial review to be conducted by the MSA. Information to be provided to CRA on an "all care no responsibility basis.")

a. Review existing contracts for non-operating ancillary services.

b. What processes did the AESO use to procure suppliers?

c. Were any of the services procured in a non-competitive environment?

4. Operating Policies and System Operation

a. Review current operating policies and system operation.

b. Review demand, supply and transmission operating factors.

c. Do these factors impede the development of a competitive market?

5. Historical Review. (The MSA will provide its own review material to CRA on an "all care no responsibility basis").

    a. Review of regulatory developments over time.

    b. Review historical contracting process between ESBI Alberta Ltd (the AESO's predecessor), the AESO and ATCO Power.

    c. Review historical development of AESO operating policies.

        i. Has the AESO exercised market power on a de facto basis?

6. Options

    a. In the absence of a competitive market, how can the fair market value of TMR services be determined?

    b. Develop options to resolve the short-term problem.

    c. Develop options for a framework that can be used to ensure that this issue is not repeated in the future.

7. Other Considerations: In the course of the work take into account the following matters:

    a. Based on your analysis should we consider changing the definition of competition for TMR in the Alberta market?

    b. Does the AESO have a procurement policy approved by senior management? (This is a factual question directed to the AESO's governance pertaining to ancillary services.)

    c. Recommended amendments should be tested by a "paper trial of procurement of TMR in the Rainbow Lake area against the acquisition of other non-operating reserves such as black start/fast ramp service.

    d. Are the parties behaving in a rational manner?

    e. What drivers are affecting the party's behaviour?

    f. The "three-point" relationship of (1) technical/operations, (2) supplier motivation, and (3) AESO motivation is an excellent analytical framework.

The competitive market should be assessed from an economic and operational perspective.

APPENDIX B: ALBERTA STATUTORY FRAMEWORK

The following sections contain relevant extracts from the Electric Utilities Act 2003, the Transmission Development Policy, and the Transmission Regulation.

B.1 ELECTRIC UTILITIES ACT, STATUTES OF ALBERTA, 2003; CHAPTER E-5.1

B.1.1 Division 1: Corporate Organization

Appointment of ISO members

(9) In carrying out any duty, responsibility or function as a member of the Independent System Operator, the member must

(a) act honestly, in good faith and in the public interest,

(b) avoid conflicts of interest, and

(c) exercise the care, diligence and skill that a reasonably prudent individual would exercise in comparable circumstances.

B.1.2 Division 2: Independent System Operator Duties and Authority

Duty to act responsibly

(16) The Independent System Operator must exercise its powers and carry out its duties, responsibilities and functions in a timely manner that is fair and responsible to provide for the safe, reliable and economic operation of the interconnected electric system and to promote a fair, efficient and openly competitive market for electricity.

Duties of Independent System Operator

(17) The Independent System Operator has the following duties:

(a) to operate the power pool in a manner that promotes the fair, efficient and openly competitive exchange of electric energy;

(b) to facilitate the operation of markets for electric energy in a manner that is fair and open and that gives all market participants wishing to participate in those markets and to exchange electric energy a reasonable opportunity to do so;

(c) to determine, according to relative economic merit, the order of dispatch of electric energy and ancillary services in Alberta and from scheduled exchanges of electric energy and ancillary services between the interconnected electric system in Alberta and electric systems outside Alberta, to satisfy the requirements for electricity in Alberta;

(d) to carry out financial settlement for all electric energy exchanged through the power pool at the pool price unless this Act or the regulations made by the Minister under section 41 provide otherwise;

(e) to manage and recover the costs of transmission line losses;

(f) to manage and recover the costs for the provision of ancillary services;

(g) to provide system access service on the transmission system and to prepare an ISO tariff;

(h) to direct the safe, reliable and economic operation of the interconnected electric system;

(i) to assess the current and future needs of market participants and plan the capability of the transmission system to meet those needs;

(j) to make arrangements for the expansion of and enhancement to the transmission system;

(k) to collect, store and disseminate information relating to the current and future electricity needs of Alberta and the capacity of the interconnected electric system to meet those needs, and make that information available to the public;

(l) to regulate and administer load settlement;

(m) to perform any other function or engage in any activity the Independent System Operator considers necessary or advisable to exercise its powers and carry out its duties, responsibilities and functions under this Act and regulations.

B.1.3 Division 4: Transmission Responsibilities of the Independent System Operator

ISO sole provider of system access service

(28) The Independent System Operator is the sole provider of system access service on the transmission system.

Providing system access service

(29) The Independent System Operator must provide system access service on the transmission system in a manner that gives all market participants wishing to exchange electric energy and ancillary services a reasonable opportunity to do so.

ISO tariff

(30), (1) The Independent System Operator must submit to the Board, for approval under Part 9, a single tariff setting out

(a) the rates to be charged by the Independent System Operator for each class of system access service, and

(b) the terms and conditions that apply to each class of system access service provided by the Independent System Operator to persons connected to the transmission system.

(2) The rates to be charged by the Independent System Operator for each class of service must reflect the prudent costs that are reasonably attributable to each class of system access service provided by the Independent System Operator, and the rates must

(a) be sufficient to recover

(i) the amounts to be paid under the approved tariff of the owner of each transmission facility,

(ii) the amounts to be paid to the owner of a generating unit in circumstances in which the Independent System Operator directs that a generating unit must continue to operate, and the costs to make prudent arrangements to manage the financial risk associated with those amounts,

(iii) farm transmission costs, and

(iv) any other prudent costs and expenses the Board considers appropriate,

(b) either be sufficient to recover the annualised amount paid to the Balancing Pool under section 82(7), or if the Independent System Operator receives an annualised amount under section 82(7), reflect that amount, and

(c) include any other costs, expenses and revenue determined in accordance with the regulations made by the Minister under section 99.

(3) The rates set out in the tariff

(a) shall not be different for owners of electric distribution systems, customers who are industrial systems or a person who has made an arrangement under section 101(2) as a result of the location of those systems or persons on the transmission system, and

(b) are not unjust or unreasonable simply because they comply with clause (a).

(4) The Independent System Operator may recover the costs of transmission line losses and the costs of arranging provision of ancillary services acquired from market participants by

(a) including either or both of those costs in the tariff, in addition to the amounts and costs described in subsection (2), in which case the Board must include in the tariff the additional costs it considers to be prudent, or

(b) establishing and charging ISO fees for either or both of those costs.

B.2 Transmission Development Policy

B.2.1 Foundation Principles

The fundamental goal of the transmission policy is to ensure that consumers are served with reliable, reasonably priced electricity, and to support continued economic growth in Alberta.

B.2.2 Principles

The following principles summarize and further articulate the fundamental goal stated above.

1. Transmission is a monopoly service. This regulatory model for provision of transmission service best serves the purposes of Alberta.

2. Transmission is essential to reliability. Dependable provision of electric service underpins a strong economy and supports the safety and well being of every Albertan.

3. Transmission policy under a vertically integrated monopoly regime, like those of history, is fundamentally different from transmission policy within a competitive market for electricity.

4. Pricing and payment for transmission is fundamentally a cost most appropriately borne by the loads that are served by the transmission system on an equal basis, regardless of location.

5. Generators will make financial commitment and contribution towards upgrades of the transmission system based on generator size and location on the system.

6. Inter-ties are essential to a well-functioning market structure. Alberta is integrated with the electric systems of our neighbours. Transmission policy and the regulatory environment must facilitate open access to larger markets, while ensuring that Alberta's needs are met.

7. The policy should support appropriate consideration of export projects including the benefits to Alberta consumers.

B.2.3 Conclusions

1. Transmission will remain a regulated monopoly. Transmission assets should be planned by the ISO and approved by the AEUB. The AEUB will regulate rates of return and recovery of transmission costs. Transmission facility applications will be reviewed and approved by the AEUB in an open and transparent process. The regulatory and approval process must be timely and efficient.

2. Transmission service must be provided using a non-discriminatory and open-access regime, administered by the ISO.

3. Transmission embedded costs will be collected from consumers based on their use of the transmission system. Generators will be required to pay for local interconnection costs and to make a financial commitment and payment for transmission system upgrades based on their size and location on the system. Economic signals and prices from the wholesale electricity market should not be adjusted or unduly distorted with transmission costs.

4. Transmission planning must be proactive in nature and must therefore lead load growth and generation development. Both population and economic growth are expected to continue in the province and transmission assets should be developed in a manner, which is prudently in advance of projected needs. It is not reasonable to expect that market signals, congestion pricing schemes or similar methods will result in timely construction of transmission facilities or assure their sufficiency to meet system needs.

5. Bulk Transmission System plans and facilities will, at a minimum, adhere to Western Electric Systems Coordinating Council (WECC) and North American Electric Reliability Council (NERC) standards and criteria to assure overall system reliability. The ISO will establish and maintain planning and operating standards and criteria for the Alberta transmission system.

6. Transmission must serve and facilitate a competitive wholesale market. Transmission internal to Alberta should be reinforced so that about 95 per cent of expected economic wholesale transactions can be realized without transmission congestion.

7. Transmission development should eliminate the need for most transmission must run (TMR) contracts and remove most congestion areas in the long-run. Temporary congestion may occur in abnormal line configurations or in isolated instances of long-term limited growth, or other extraordinary circumstances.

The ISO should however, be provided with some flexibility to consider TMR contracts where they are technically viable and a superior economic alternative (e.g. in remote areas with low growth potential) over the long-term. Transmission must-run (TMR) may be an appropriate solution in those limited cases.

Where TMR is used, the cost of TMR (or similar) arrangements should be recovered from load customers in the same manner as wire costs as part of the transmission tariff. In the few cases where transmission constraints are not removed, TMR arrangements should not set or distort market prices. Rather TMR contracts should be provided on a cost-of service basis by the owner and should not be a vehicle for exercising market power in a region that is transmission deficient.

8. Transmission internal to Alberta should be reinforced so that under normal conditions, the existing inter-ties can import and export power on a continuous basis, in accordance with their design capability.

9. Projects primarily intended for export should be considered on a case-by-case basis. Pricing for such projects would normally be paid by the project beneficiaries (i.e. the exporters). Where residual benefits to the internal grid are demonstrated, consumers may fund system upgrades, in a manner consistent with the benefits.

B.3 TRANSMISSION REGULATION

Long-Term Planning – 20-Year Plan

3 As part of its duties under section 17 of the Act, the ISO must

(a) no later than July 1, 2005, prepare and maintain a long-term transmission system outlook document that projects, for at least the next 20 years,

(i) the forecast load on the interconnected electric system, including exports,

(ii) the anticipated generation capacity, including appropriate reserves and imports required to meet the forecast load,

(iii) the timing and location of future generation additions,

(iv) the transmission facilities required to meet the forecast load, imports, exports and anticipated generation capacity, including appropriate reserves, in a timely and efficient way,

(v) the transmission facilities required to provide for the efficient and reliable access to jurisdiction outside Alberta, and

(vi) other matters related to the items described in subclauses (i) to (v) that the ISO considers appropriate;

(b) update the long-term transmission system outlook document periodically as required, but at least every 4 years;

(c) make the long-term transmission system outlook document, and the updates made to it, publicly available and file copies of them with the Board for information.

Long-Term Planning – 10-Year Plan

4(1) As part of its duties under section 17 of the Act, the ISO must

(a) no later than December 31, 2004, prepare and maintain a transmission system plan in greater detail than the long-term transmission system outlook document that projects, for at least the next 10 years,

(i) the forecast load on the interconnected electric system, including exports,

(ii) the anticipated generation capacity, including appropriate reserves and imports required to meet the forecast load,

(iii) the timing and location of the future generation additions,

(iv) the transmission facilities required to meet the forecast load, imports, exports and anticipated generation capacity, including appropriate reserves, in a timely and efficient way,

(v) the transmission facilities required to provide for the efficient and reliable access to jurisdiction outside Alberta, and

(vi) other matters related to the items described in subclauses (i) to (v) that the ISO considers appropriate.

(b) update the transmission system plan periodically as required, but at least every 2 years;

(c) make the transmission system plan, including the assumptions and supporting data on which the plan is based, and the updates made to the plan, publicly available;

(d) file copies of the transmission system plan, assumptions, data and updates with the Board for information.

4(2) The transmission system plan must

(a) identify the transmission facility projects the ISO proposes to initiate by a needs identification document within 5 years of the date of the plan and within 5 years of each update of the plan, and

(b) for each transmission facility project identified, provide an anticipated implementation schedule for the project.

Needs Identification Document

5(1) When the ISO prepares a needs identification document under section 34(1) of the Act, the ISO may

(a) rely on the forecasts referred to in the long-term transmission system outlook document and transmission system plans, and

(b) indicate how the needs identification document relates to the long-term transmission system outlook document and transmission system plans.

5(2) In addition to the requirements for a needs identification document described in section 34(1) of the Act, the document must describe the timing and nature of the need, constraint or condition affecting or that will affect the operation, efficiency and reliability of the transmission system, including

(a) an assessment of current transmission capability;

(b) the planning criteria used for the assessment of transmission system capability;

(c) a 10 year forecast of the load on the interconnected electric system;

(d) a 10-year forecast of generation capacity and appropriate reserves required to meet the forecast load;

(e) the studies and analysis performed in identifying the timing and nature of the need affecting or that will affect the identified constraint or condition;

(f) the options considered for alleviating the constraint or condition;

(g) the technical and economic comparison of the options considered, including

(i) the impact on generation must-run requirements described in section 30(2)(a)(ii) of the Act;

(ii) how the options relate to the transmission system outlook document;

(iii) the evaluation of operational efficiency and reliability and the improvements provided by each option;

(iv) an evaluation of each option with respect to reliability standards and the planning criteria used for the assessment of transmission system capability;

(v) the proposed transmission substation and line configurations for each option considered;

(vi) the evaluation of factors respecting implementation of each option, including the timing and risks during construction;

(vii) environmental and other considerations;

(h) the ISO's recommendation of a preferred option, including

(i) the rationale for selecting the option, and

(ii) the implementation scheduled for the option;

(i) if appropriate,

(i) describing any operations preparatory to construction of a transmission facility, including engineering, purchase of materials, purchase of land or options to purchase land for future use or acquire a right or interest in land for future use as a right of way, as may be necessary, and

(ii) describing the rationale, including the assumptions and supporting data on which the rationale is based, supporting the nature of the preparatory operations and estimating the cost of the operations referred to in subclause (i).

5(3) If the ISO's preferred option under subsection (2)(h) is to construct a transmission facility at a future date, the ISO must

(a) be reasonably certain that, in the future, a transmission facility is needed, and for the purpose of determining the certainty of the need, the ISO may specify milestones including

(i) load growth,

(ii) generation addition,

(iii) commitments by the prospective owners of generating units to construct a unit,

(iv) the receipt of payment of local interconnection costs under Part 4,

(v) the issue of permits or approvals, or meeting other legal requirements, for the construction of a generating unit, and

(vi) any other indicators prescribed by the ISO determining the certainty of the need for the construction of a transmission facility,

and

(b) identify the process by which the ISO will monitor and determine whether the milestones identified under clause (a) are met.

5(4) When the milestones described in accordance with subsection (3) are met, in full or in part, the ISO may make a direction to a TFO under section 35(1)(a) of the Act.

5(5) Despite section 34(1) of the Act, a needs identification document is not required for

(a) maintenance upgrades or enhancements to a transmission facility proposed by a TFO if the upgrades or enhancements improve the efficiency or operability of the transmission facility but do not materially affect transmission facility capacity, or

(b) a system access service requests for customer load and generator interconnections, if the ISO complies with Board directives with respect to those requests.

B.3.1 Part 2 Transmission System Criteria and Reliability Standards

Matters taken into account

8(1) In making rules under section 20 of the Act, and in exercising its duties under section 17 of the Act, the ISO must

(a) plan a transmission system that satisfies reliability standards, unless the ISO decides that to do so would not provide for a safe, reliable or efficient transmission system;

(b) ensure that transmission facilities adhere to reliability standards;

(c) monitor and ensure overall reliability of the interconnected electric system;

(d) comply with directives of the Board;

(e) taking into consideration the characteristics and expected availability of generating units, plan a transmission system that

(i) is sufficiently robust to allow for transmission of 100% of anticipated in-merit electric energy referred to in section 17(c) of the Act when all transmission facilities are in service, and

(ii) is adequate to allow for transmission, on an annual basis, of at least 95% of all anticipated in-merit electric energy referred to in section 17(c) of the Act when operating under abnormal operating conditions;

(f) make arrangements for the expansion or enhancement of the transmission system so that, under normal operating conditions, all anticipated in-merit electric energy referred to in clause (e)(i) and (ii) can be dispatched without constraint;

(g) make arrangements for the expansion or enhancement of the transmission system so that, under normal operating conditions, the transmission system interconnections with jurisdictions outside Albert can import and export electricity on a continuous basis, at or near the transmission facility's path rating;

(h) make rules respecting the preparation of needs identification documents for, and the planning and processing of, enhancements or upgrades to transmission facilities that provide transmission capacity to import or export electricity to or from Alberta in excess of the existing transmission facilities' path rating.

8(2) A decision by the ISO under subsection (1)(a) that a reliability standard would not be safe, reliable or efficient must be filed by the ISO with Board for approval.

8(3) In planning and arranging for enhancements or upgrades to the transmission system, the ISO may make or provide for specific and limited exceptions to the matters described in subsection (1)(e), (f) and (g), or any of them, and if it does so, must

(a) file the exceptions with the Board for approval, and

(b) specify the period of time the exception applies.

8(4) In considering the design and planning for the transmission system, the ISO may consider specific and limited exceptions to the requirements of subsection (1) and propose a non-wires solution

(a) in areas where there is limited potential for growth or load, and the cost of the non-wires solution is materially less than the life-cycle cost of the transmission wires solution, compared over an equivalent study period, or

(b) if the non-wires solution is required to ensure reliable service to do the shorter lead time of the non-wires solution, for a specified limited period of time.

8(5) The ISO must make rules respecting the operation of a generating unit necessary to alleviate a transmission system constraint and include in the ISO tariff the recovery of those costs.

Managing transmission constraints

9(1) The ISO must make rules and adopt practices respecting the operation of the transmission system and the management of transmission constraints that may occur from time to time.

9(2) If, in managing transmission constraints, there is a dispatch to a generating unit(s) that is out-of-merit, the unit(s) must not set the pool price.

9(3) In circumstances described under subsection (2), the pool price will be determined using the last in-merit generator actually dispatched.

Reliability management agreements

10(1) After this Regulation comes into force, the ISO must not enter into an arrangement or agreement under section 9(5) of the Act respecting reliability standards, or amend or change those arrangements or agreements, without the approval of the Board.

10(2) Arrangements and agreements entered into under section 9(5) of the Act must be made available to the public except when the ISO considers it not to be in the public interest to do so, in which case an explanation for the non-disclosure must be given.

10(3) In addition to the duties it has under section 17 of the Act, the ISO must

(a) monitor the results of reliability standards and make the results publicly available, and

(b) file a copy of the monitoring results with the Board for information.

10(4) The ISO must participate in the development of new or modifications to reliability standards.

Reliability standards compliance reports

11(1) The ISO must make periodic reports to the Board respecting compliance by the ISO and TFOs with reliability standards.

11(2) The TFOs must assist the ISO in preparing reports under subsection (1).

APPENDIX C: ARTICLE 4 AND 24 REGULATORY HISTORY

C.1 APPENDIX E (EAL TARIFF), JULY 2000

EAL applied to the EUB for an obligation on PPA buyers to supply certain System Support Services (SSS). These would be deemed to have a standing offer per Table A of Appendix E of the application. The intention was to reasonably compensate PPA Buyers for incremental costs and foregone opportunity value incurred in providing SSS, including operating reserves, TMR and constrained down.

This was rejected by the EUB on the grounds that provision of SSS could not be compelled through the Tariff.

C.2 INTERIM APPROVAL OF ARTICLE 4 (EAL TARIFF), AUGUST 2000

Article 4.4: In summary, allowed for the Transmission Administrator or System Controller to "conscript" dispatch to ensure the maintenance of system security[36].

This plant was compensated for each MW of conscripted dispatch at a rate equal to the maximum of their offer price into the market or the prevailing pool price.

C.3 INTERIM APPROVAL OF ARTICLE 24 (EMERGENCY PROVISION OF SSS), DECEMBER 2000

Article 24.1: During an Emergency, the System Controller may require a Customer to operate its Generating Unit to provide System Support Service. For the period during which the Emergency persists, Customers required to provide System Support Services shall be compensated as provided in sections 24.2 or 24.3 (whichever is applicable).

Article 24.2: If at the time of the Emergency the Customer has an existing contract with the Transmission Administrator, either directly or indirectly, to provide System Support Services (the "Existing Contract"), then the amount to be paid to the Customer by the Transmission Administrator for the System Support Services shall be determined according to the terms of the Existing Contract.

Article 24.3: If the Customer does not have an Existing Contract, then the amount to be paid to the Customer by the Transmission Administrator in respect of each ancillary service provided shall be the greater of:

36 Simplified summary

(a) The sum, over all hours during which the Customer is required to provide the System Support Service pursuant to section 24.1, of the product of the hourly MW dispatch and the highest price paid in the hour to Customers providing System Support Service pursuant to Article 24.2; or

(b) The sum, over all hours during which the Customer is required to provide the System Support Service pursuant to section 24.1, of the product of the hourly MW dispatch and 110% of the energy price in the hour as set by the Power Pool of Alberta plus any additional charges from the Power Pool of Alberta (including but not limited to uplift charges) and charges from the TA; or

(c) The direct costs incurred by the Customer to provide the required System Support Service, plus ten percent. Direct costs include, but are not limited to, Generating Unit start-up costs, fuel costs and variable operation and maintenance costs; however, direct costs do not include indirect, incidental, consequential, or special damages arising out of or relating to the Customer providing System Support Services; or

(d) The verifiable opportunity cost incurred by the Customer to supply the required System Support Services.

C.4 Refiling of Article 4 and Article 24, March 2001

C.4.1 Article 4, System Support Services

Article 4 was strengthened to require the provision of SSS as a condition of system access. The pricing provisions in Article 4.3 remained the same.

Article 4.1: From and after the effective date of the Tariff, certain Customers may be eligible and required to provide under- frequency load shedding. The provisions with respect to those requirements, and the credits therefore, are set out in Rate Schedule Under-Frequency Load Shedding ("UFS").

Article 4.2: Failure by any Customer to whom UFS applies, to comply with the requirements thereof shall provide the Transmission Administrator with the right, at its sole discretion, to withhold, limit or discontinue System Access Service to such Customer. Nothing in this paragraph shall, however, affect or derogate from the right of the WSCC[37] to levy penalties or the obligation of the Customer, if any, to pay such penalties as a result of failure to provide System Support Services to the Transmission Administrator as contemplated herein.

37 Western Systems Coordinating Council (WSCC) is now referred to as Western Electricity Coordinating Council (WECC).

C.4.2 Article 24, Emergency Provision of System Support Services

Article 24 was amended to include pricing provision (e):

Article 24.3: If the Customer does not have an Existing Contract, then the amount to be paid to the Customer by the Transmission Administrator in respect of each ancillary service provided shall be the greater of:

(a) – (d) unchanged

(e) The sum, over all hours during which the Customer is required to provide the System Support Service pursuant to section 24.1, of the product of the hourly MW dispatch and the hourly difference between the Customer Offer Price and the Pool Price, where Customer Offer Price is the current valid offer into the Power Pool or, if no current valid offer exists, the average of the offers spanning the most recent complete daily Off-Peak or On-Peak period, as the case may be, that have been made to and accepted by the Power Pool as valid offers.

Subsequently the EUB stated that had they known Engage was going to use the current offer price (COP) provision in Article 24.3(e), approved on an interim basis, it would have likely not included this provision. EUB concluded that reliance on 24(e) by Engage was designed so that the units would not be dispatched into the market.

C.5 REFILING ARTICLE 24, EFFECTIVE JANUARY 2001

Article 24 was amended to delete pricing provision (e) and include pricing provision (f).

Article 24.3: If the Customer does not have an Existing Contract, then the amount to be paid to the Customer by the Transmission Administrator in respect of each ancillary service provided shall be the greater of:

(a) – (d) largely unchanged, but some modifications to reflect the cost structure of PPA agreements and to allow for offsetting revenues.

(e) DELETED by Board Decision 2002-103

(f) Compensation, at the discretion of the Board, in addition to the highest compensation payable under Article 24.3 (a) to (d) required to provide just and reasonable total compensation to the provider of Ancillary Services on a sustained basis in the absence of a contract with the TA.

C.6 TRANSMISSION REGULATION

C.6.1 Part 5 – Transmission System Losses and Credits

Recovery of Must Run Costs

23 (1) For the purpose of section (30)(2)(a)(ii) of the Act, the compensation must be no greater than an amount that would result in the recovery of fixed, operating, and maintenance costs, including a reasonable rate of return, using a methodology described in the ISO Tariff.

(2) The ISO must include in the ISO Tariff a cost determination methodology and related terms and conditions of service for the purposes of subsection (1).

(3) The ISO must make rules regarding transmission must-run generating units and the determination of pool price so that the pool price will be determined using the last in-merit generating unit(s) dispatched.

(4) Costs associated with subsection (1) must be included and recovered under the ISO Tariff in the same manner as transmission costs under section (30)(a)(i).

C.6.2 Part 6 – Board Responsibilities

ISO Tariff – Transmission System Considerations

(30) When considering an application for approval of the ISO tariff under sections 121 and 122 of the Act, the Board must

(a) ensure

(i) the just and reasonable costs of the transmission system as a whole charged to the owners of electric distribution systems, customers who are industrial and persons who have made an arrangement under section 101(2) of the Act, and exporters, to the extent required by the ISO tariff, and

(ii) the owner payable by an owner of an electric distribution system is recoverable in the tariff of the owner of the electric distribution system;

(b) ensure owners of generating units are charged local interconnection costs to connect their generating unit to the transmission system, and are charged a financial contribution towards transmission system upgrades, and for location-based costs of losses;

(c) consider all just and reasonable costs related to arrangements and agreements described in section 9(5) of the Act.

APPENDIX D: IBOC/LBC-SO/TMR REGULATORY HISTORY

D.1 OVERVIEW OF REGULATORY PROCESSES

D.1.1 November 23, 1998

U98179 ESBI Alberta Ltd. Approval of Financial Arrangements for Purchase of Transmission Support Services from Cu Power Canada Limited's Poplar Hill Power Plant

ESBI Alberta Ltd. (EAL) filed an application with the AEUB on 1 September 1998 for approval of its Energy Services Agreement, dated 12 August 1998, with CU Power Canada Limited (CUPCAN, also known as ATCO), pursuant to the Transmission Administrator Deficiency Correction Regulation, A.R. 163/98, O.C. 345/98.

The Board noted that there was agreement among all the parties that there was an urgent need for voltage support and reactive-power to serve Northwest Alberta, especially in the Grande Prairie region. CUPCAN's Poplar Hill Power Plant, which was being completed and commissioned, would help to meet that need in the immediate future. The Board also noted that, although parties had concerns about some aspects of the Application, there were no formal objections to its approval at the close of the hearing.

D.1.2 February 2, 2000

2000-1 ESBI Alberta Ltd. 1999/2000 General Rate Application Phase 1 And Phase 2 (Application 990005)

Board directs EAL to re-file 1999/2000 GTA by March 1, 2000. Decision 2000-1 dealt extensively with System Expansion Related Pricing (SERP) proposed by EAL. SERP was intended to send an on-tariff locational based signal to generating units to deal with transmission constraints. Although the Board rejected SERP as a solution, it thought it appropriate to use the SERP analysis as a ceiling price for a Standing Offer process. The Board also considered that using the system of SERP credits as a ceiling would also provide the appropriate incentives for generation in the Northwest part of the province.

Therefore, from the SERP analysis came two-approaches to alternatives to transmission expansion to deal with congestion:

- *Invitation To Bid On Credits (IBOC)*: This was intended to deal with shorter-term critical congestion issues in Southern Alberta. The TA consistently maintained that, absent some action prior to December 2001, potential voltage collapse was imminent due to load growth in the Calgary area. The IBOC process was therefore the TA's response to a RFP process.

- *Locational Based Credits – Standing Offer (LBC-SO)*: As a continuation of the short term IBOC approach, a similar process (LBC-SO) was proposed (and preferred over the IBOC process, which was intended to deal with critical near-term issues). LBC-SO would essentially work like a Dutch Auction, where the TA would use portions of its SERP analysis to determine the lowest starting point for the energy credit, and the credit would be stepped up in stages to attract auction participants as required.

The Standing Offer Process was thought to have the following advantages:

- In the event of over-subscription, it is market driven and could lower costs;

- Through increasing steps of offer prices, it was market driven and could lower prices (even if not over-subscribed);

- It would target the specific area or problem and offer incentives to those offering solutions;

- It would reduce risks relating to the PPAs;

- It would be flexible and transparent, and would ensure that incumbents did not have an unfair advantage; and

- The ceiling on the standing offer was economically determined by the PV of avoided cost of transmission alternative.

The Board considered RFPs (IBOCs) useful in urgent situations, and determined that a 20-year term was most likely to be commercially reasonable.

D.1.3 April 5, 2000

2000-24 ESBI Alberta Ltd. 1999/2000 Tariff Application Refiling – Part A Invitation To Bid On Credits (IBOC)

On March 20, 2000, EAL submitted detailed bid procedures and a pro-forma contract for the IBOC process. Interested parties raised a variety of issues with the IBOC, and to a lesser extent the LBC-SO process, which were addressed in this decision. The AEUB approved EAL's request to immediately commence an IBOC for a maximum of 500MW, and agreed that EAL should not necessarily accept the lowest bid or any bid. EAL was directed to prudently choose a portfolio of bids that would provide project diversity, operational diversity and the lowest credit payable, compared on a present worth basis, and that will also satisfy the timing of transmission reliability concerns.

In service dates for IBOC were set at Dec. 15, 2001 (200MW to satisfy immediate transmission concerns). Targeting the Calgary area was based on sound technical analysis and transmission planning principles.[38] Therefore determined bids must be within 50 mile radius of Calgary. The EUB considered that the experience gained in the course of the IBOC process should provide valuable benchmark in establishing market based LBC-SO.

D.1.4 Summary of Completed IBOC Agreements

2000-47 ESBI Alberta Ltd IBOC Contract Approval

The AEUB approved three Calgary-area IBOC contracts for 20-year terms (Figure 4).

Figure 4: IBOC Service Providers in the North West Region

Generation Asset and Owner	Credit Capacity MW	Variable Cost $/MWh	Contract Term	Payment Details		
				Incentive Payment	Monthly LBC Payment	Supple-mental Payments
Carseland TransCanada	81	$3.75	June 20, 2000	✓	✓	✓
Balzac Nexen/EnCana	97	$3.75	June 20, 2000*	✓	✓	✓

38 Clear evidence was submitted in hearings that generation Calgary area was urgently needed.

Generation Asset and Owner	Credit Capacity MW	Variable Cost $/MWh	Contract Term	Payment Details		
				Incentive Payment	Monthly LBC Payment	Supple-mental Payments
Cavalier – Stage 1 Encana	78	$3.75	July 22, 2001	✓	✓	✓
Cavalier – Stage 2 Encana	25	$3.25	Dec 1, 2001	✓	✓	✓

Notes:
*This arrangement has been terminated.

The AEUB considered that the IBOC process was conducted in a fair manner and allowed for adequate testing of the application. EAL had achieved fair and reasonable balance between timeliness of the process, confidentiality of bidders and the public interest.

The AEUB ordered the proposed LBC-SO timetable to be completed by July 19, 2000 so that LBC-SO process could be commenced by Sept 15, 2000. EAL subsequently refiled the proposed LBC-SO process. Along with requesting approval for the process, it requested approval to launch standing offers to incent generation in Southern Alberta, Lloydminster and Grande Prairie.

D.1.5 December 14, 2000

2000-76 ESBI Alberta Ltd. Part C: 1999/2000 Phase I And II Tariff Application Location Based Credits – Standing Offer.

The AEUB issued a number of directions to EAL in relation to the proposed LBC-SO process, including:

1. To proceed with a process to procure the requested generation through incentives, for all four zones as follows:
   - Southern Alberta Zones 1&2 – combined total of 100 MW in 2002/2003;
   - Southern Alberta Zones 1&2 – combined total of 100 MW in 2004/2005;
   - Grande Prairie Zone 3 total of 100 MW in 2002/2003;
   - Lloydminster Zone 4 total of 50 MW in 2002/2003.

2. To incorporate the additional 100 MW required in southern Alberta for 2004 into the 2002 LBC-SO procurement process.

3. To adhere to the following four main principles in the design of any future LBC-SO proposals:

   - A standing offer for generation to fulfil a transmission need shall be subject to the same scrutiny that a transmission facility would receive in terms of need and cost.

   - Generation should normally only be procured through incentives when the generator solution is significantly more economical than a transmission solution.

   - Generation should be available to run on a basis similar to transmission availability.

   - Transmission options need to continue to be pursued so that long term availability and reliability of a transmission line, the advantages of a strong transmission backbone, and the level playing field provided to new competitors are achieved.

4. To fully address the appropriate planning criteria when it files its ten year transmission development plan with the Board in 2001 for approval. EAL should provide the Board with sufficient quantitative and qualitative analyses to support its ongoing use of selective N-2 criteria for transmission expansion planning purposes.

8. To submit the annual transmission development plan to the Board for approval. The development plan, at minimum, should include and address the following items:

   - A load forecast;

   - A generation forecast;

   - Appropriate reliability criteria;

   - Assumptions;

   - A model of the system;

   - Contingency studies that demonstrate violation of the criteria;

   - An assessment of the risk associated with violating the criteria;

   - Probabilistic analysis of the various contingencies;

   - An assessment of the costs and benefits of potential solutions;

- The proposed ceiling prices for transmission alternatives, consistent with the Board findings in this Decision;
- Proposed actions to "debottleneck" the AIES;
- Recommended transmission projects; and
- A declaration of stakeholder involvement and outstanding concerns.

9. To use a 20-year contract term for the LBC-SO program.

10. In its notification to parties, prior to the opening of an LBC-SO offer, to include the number of steps, the frequency of changing the offer price, and the opening offer price.

11. To review the operational guidelines, with respect to the criteria used for the dispatch of TMR generation, with the parties during their ongoing discussions with a view to settling this narrow difference and to include such guidelines it its refiling.

12. To establish a minimum amount of annual hours for which EAL would be contractually obligated to pay the LBC to LBC-SO generators during each year of the 20-year contract term.

13. To include an arbitration provision to deal with unforeseen circumstances that may cause the supplemental payment formula to yield unintended results during the life of the contract.

14. To develop contract terms to include the general intent of the following provisions:

    - A provision that will allow changes to be made, at the request of either party, to the supplemental payment formula in the event that unforeseen circumstances cause the supplemental formula to no longer yield reasonable results.
    - A dispute resolution process. If the above changes were agreed to voluntarily by the generator and the TA, the provision would be subject to EUB approval. Alternatively, either party could engage binding arbitration.
    - A decision and dispatch process that ensures that the TA must pre-authorize and request supplemental payment claims and be aware of the potential magnitude of the claims before they occur.
    - A communication and documentation process that ensures that the TA can effectively advise the generator when the TA will require the generator to run to be eligible for supplemental payments.

- A procedure that ensures that in any event, all supplemental payments are considered final following a 1-year period.

16. To define and include in the contract the following:

    - The definition of what constitutes plant acceptance and that the generator is fully operational.
    - A clear definition of the required operational date. After this date, the following revised penalty provisions will apply.
    - Contract provisions that provide for liquidated damages in the event of default.
    - Eligibility for incentive payments for generation being in operation ahead of the required date up to 6 months early, similar to the IBOC contract.

17. To include a cost-benefit analysis of having distribution-connected generators participate in the process.

18. In its next LBC-SO application, to address whether other transmission solutions should also be eligible for procurement credits.

19. In its next Transmission Development Plan, to identify the timing and qualifying circumstances for eligibility for SO credits beyond 2004.

23. To clearly describe its bid-down procedure and to use a numerical example to show how the process would work including generators of sizes ranging from 20 MW to 100 MW. This example should include the process used when projects smaller than the total credit capacity are the winners in a bid down process. The proposed procedure should be developed with input from stakeholders to ensure that it is a workable and acceptable proposition.

25. To address administrative issues associated with the acceptances of LBC-SO by generators including the following:

    - Confidence that parties who wished to participate and should be considered in the time for equal initial consideration were not restricted from doing as a result of technical difficulties with the process of faxing in acceptances.
    - Protection of confidentiality within EAL's offices of the number of parties accepting a SO and who the parties are. This applies for both a SO offer level and any bid-down procedure.
    - Providing confidential confirmation of receipt to parties following each submission.

- Procedures in the event of technical difficulties associated with receipt of faxed acceptances or the inability of the fax machines to receive all the proposals within the specified time. Procedures should address extending the time for equal initial consideration.

26. At the time that EAL submits the results of the LBC-SO process for approval by the Board, to complete the following:

    - Explain the results of its administrative procedures of its offer and bid down process;
    - Explain the procedures undertaken to protect confidentiality, including the points outlined above; and
    - To submit a compliance letter by a recognized national audit firm indicating acceptable procedures were followed.

27. To file with the Board by December 18, 2000, a proposed schedule for the LBC SO process that should include the following:

    - The refiling date;
    - The date for comments by parties;
    - The expected Decision date by the Board;
    - The commencement of the LBC SO process;
    - An expected filing date for the application for Board approval of the contracts with the selected generators; and
    - The expected Hearing date for the approval of the contracts.

D.1.6 January 2001 to March 2001

EAL subsequently submitted a number of refilings responding to these directions:

- *January 22, 2001*: EAL re-filed LBC-SO Process in response to the AEUB's (2000-76) decision;
- *February 12, 2001*: EAL re-files revised LBC-SO that reflects results of discussions around Jan 22, 2001 refiling;
- *February 19, 2001*: The AEUB directs a series of rewording and changes to LBC-SO Offer (2001-13 Part D: Locational Based Credits – Standing Offer First Refiling Pursuant To Decision 2000-76);
- *February 23, 2001*: EAL submits second refilling in accordance with decision 2001-13. Board directs EAL to commence the LBC-SO using its judgment after accommodating changes; and

- *March 2, 2001*: LBC-SO Entitlement Offer approved by the Board. Pro Forma attached to approved filing (2001-18 ESBI Alberta Ltd. Part F: Location Based Credits – Standing Offer Filing for Acknowledgement and Approval pursuant to Decision 2001-17).

D.1.7 May 9, 2001

2001-35 plus Addendum A ESBI Alberta Ltd. LBC-SO Contract Approval, Part G: Southern Alberta and Grande Prairie

AEUB approved and bound future TAs to the following 20 year LBC-SO contracts:

- Encana Medicine Hat (Zone 2) for 75MW @ $1.75/MWh (COD Dec 1, 2004). Although this contract was approved, the unit was shelved by Encana due to project economics.
- TransCanada Energy Bear Creek, Grand Prairie (Zone 3) for 50MW @ 2.75/MWh (COD Dec 1, 2002).
- Calpine Calgary Energy Centre (Zone 1) for 125MW @ $2.75/MWh. (COD 1st 100 MW, Dec 1, 2002; COD 2nd 25MW Dec 1, 2004).

D.1.8 July 2001

July 30, 2001, 2002 -070 ESBI Alberta Ltd. Valleyview Transmission Must Run Services, Agreement Compliance Filing

On March 8, 2001, EAL opened the LBC-SO in Southern Alberta, Grande Prairie, and Lloydminster, but closed the process in the Grande Prairie zone to assess a proposal from ATCO Power for an alternative solution for the area (Valleyview Proposal). EAL determined that the Valleyview Proposal met its technical and cost criteria. The Valleyview Proposal was for a credit capacity of only 40 MW, whereas 100 MW was required in the Grande Prairie zone. Therefore, EAL reopened the LBC-SO in the Grande Prairie zone in order to fulfil the remaining requirement of 60 MW for the zone. The Grande Prairie LBC-SO resulted in TransCanada Energy Ltd. (TCE) accepting 50 MW of generation at a LBC Rate of $2.75/MWh (TCE Bear Creek). EAL evaluated the Valleyview Proposal in combination with the TCE Acceptance and determined that 90 MW would satisfy the requirements for the zone. Accordingly, the LBC SO process in Grande Prairie was brought to a close.

On July 13, 2001, EAL and ATCO Power executed the Valleyview TMR Agreement. EAL submitted that this Agreement essentially took the form of the LBC-SO Agreements previously approved by the Board, but revised to permit the use of a synchronous condenser.

D.1.9 Summary of Completed LBC-SO Agreements

Figure 5 summarises completed LBC-SO agreements in the Northwest region.

Figure 5: LBC-SO Service Providers in the North West Region

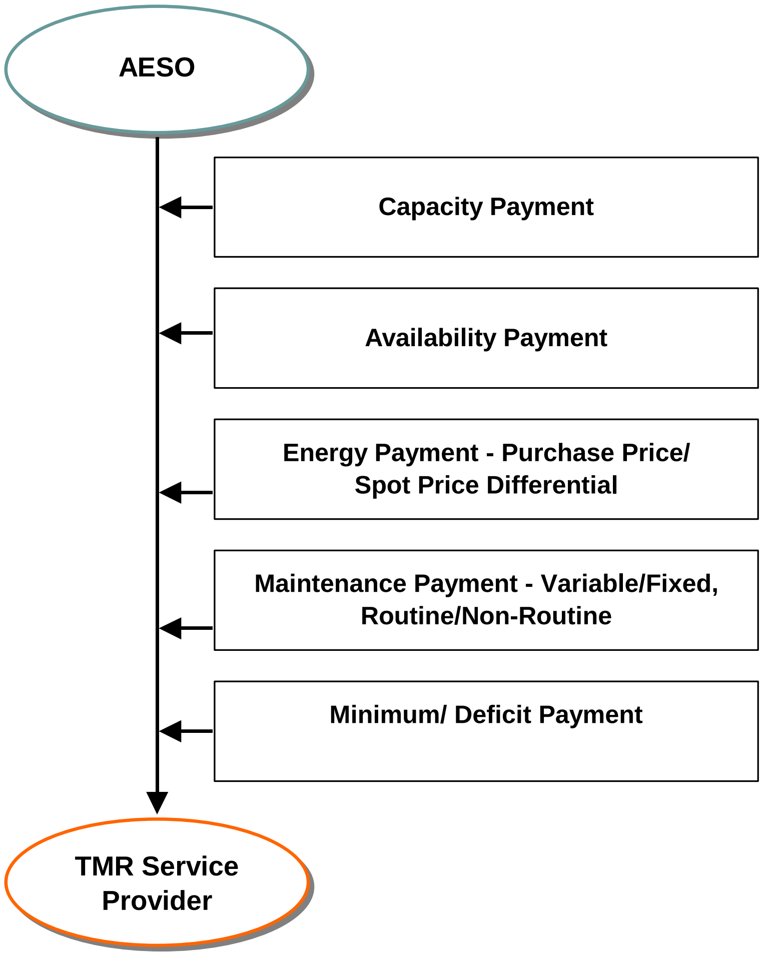
Generation Asset and Owner	Credit Capacity MW	Zone	Contract Term	Payment Details			
				Incentive Payment	Monthly LBC Payment	Annual Minimum Payment	Supplemental Payment
Valleyview* ATCO Power	40	Grand Prairie	May 21, 2002	✓	✓	✓	✓
Calpine Energy Calpine Energy	100 25	South West	December 1, 2002 December 1, 2004	✓	✓	✓	
Bear Creek	50	Grand Prairie	December 1, 2002	✓	✓	✓	✓

Notes:
* Valleyview can provide energy and reactive power services. The agreement was signed in parallel to the LBC-SO process, but was not officially an LBC-SO contract.

D.2 TMR AGREEMENTS

The AESO entered into a number of TMR arrangements with generators in the North West Region. These arrangements are bilateral negotiated arrangements between the service provider and the AESO. Negotiations for the procurement of TMR services date back to the late 1990s and the procurement of services under bilateral contracts has continued to the present date. Figure 6 provides an overview of the structure of these agreements.

Figure 6: Structure TMR Agreements



APPENDIX E: REVIEW OF INTERNATIONAL TMR ARRANGEMENTS

The following provides an overview of TMR arrangements in a number of wholesale electricity markets. In part this discussion relies on information provided to us by the MSA.[39] We note that internationally, 'transmission must-run' (TMR) arrangements tend to be referred to as 'reliability must-run' (RMR), and where applicable we have adopted this convention.

E.1 NATIONAL ELECTRICITY MARKET (NEM)

The National Electricity Market (NEM) covers the Australian states of Queensland, New South Wales, the Australian Capital Territory, Victoria and South Australia, and shortly, Tasmania.[40]

E.1.1 Operations and Governance of the NEM

The National Electricity Market Management Company Limited (NEMMCO) administers and manages the NEM, subject to the provisions of the National Electricity Code (Code). The Code sets out the market rules that apply to market operations, power system security, network connection and access, and pricing for network services in the NEM. The Code requires NEMMCO to operate the wholesale electricity market in a way that:

- Is competitive;
- Facilitates choice of supplier for all end-use customers;
- Provides open access to transmission and distribution networks;
- Does not favour existing market participants over potential market participants;
- Does not favour one fuel type or technology over another; and
- Does not favour intrastate over interstate trading.

39 MSA, "Draft Review of Jurisdictions", December 2005.

40 National Electricity Market Management Company, "An Introduction to Australia's National Electricity Market", June 2004.

NEMMCO determines a half-hourly spot price at each ‘regional reference node’ (RRN), and spot prices at RRNs separate between regions when inter-regional constraints on ‘interconnectors’ – transmission lines connecting adjacent NEM regions – bind.[41] Intra-regional constraints are not priced as part of the spot market calculation, since ‘constrained-on’ generators may not set the market-clearing price. However a system of non-firm hedges are sold by NEMMCO which give market participants rights to a share of the “settlement residue” that is created when regional prices separate as a result of congestion. For settlement purposes, losses are accounted for:

- Within regions by fixed, intra-regional loss factors between the RRN and customer/generation connection points; and
- Between regions, by inter-regional loss factor equations applied to flows on interconnectors.

As part of its planning and market information obligations, NEMMCO prepares an annual Statement of Opportunities (SOO). This publication is a 10-year forecast that provides information to assist market participants in assessing the future need for electricity generating capacity, demand side capacity, and augmentation of the network to support the operation of the NEM. From 2004, the SOO will incorporate an Annual National Transmission Statement (ANTS) to provide an integrated estimate of the current state and potential future development of major national transmission flow paths. The obligation to provide network planning information to market participants also extends to the regional transmission network service providers (TNSPs), who own and operate the regional transmission networks.

The Australian electricity supply industry is undergoing reforms of its regulatory and governance framework. Two new statutory bodies have been established:

- The Australian Energy Market Commission (AEMC) will be responsible for rule-making and market development; and
- The Australian Energy Regulator (AER) will be responsible for the regulation of network access, the regulation of the transmission networks, the enforcement of market rules, and the regulation of retail and distribution arrangements.

Given the regional structure of the NEM, network support services – the equivalent to TMR/RMR services – also differ for intra- and inter-regional network constraints.

41 In addition to the energy market, NEMMCO operates eight separate markets for the delivery of frequency control ancillary services (FCAS), and purchases network control ancillary services (NCAS) under agreements with service providers.

E.1.2 Intra-Regional Network Support Agreements

A TNSP must analyse the expected future operation of its transmission network and undertake regular planning exercises with a minimum planning period of 10 years. If planning processes indicate that relevant technical limits on the network will be exceeded, the TNSP must take corrective action, which may include network augmentation or non-network alternatives. The degree of regulatory scrutiny of any investment/agreements that are entered into varies by size and type of investment, but fundamentally the regulatory framework encourages TNSPs to adopt the least-cost solution to address an identified network requirement. These may hence include local generation, provision of network support by existing generation, demand side management (DSM) initiatives and network augmentations.

Network Support Agreements

TNSPs' annual planning statements provide information concerning identified opportunities for market participants to enable interested parties to develop solutions. Processes for proposed network developments then focus on:

- Identifying anticipated network limitations and constraints that may arise over the next five years;
- Notifying Code participants of anticipated limitations within the timeframe required for corrective action;
- Seek information from market participants and interested parties on feasible non-network solutions to address anticipated constraints.

For emerging network limitations which may result in large network assets, TNSPs may issue detailed information papers outlining the limitations to assist in identifying non-network solutions.

If generation has been contracted under a network support agreement, the relevant TNSP must advise NEMMCO as such. NEMMCO will constrain the generating unit on and as such the generating unit will not be eligible to set spot prices when constrained on.

Payment for network support services is a matter for negotiation between the TNSP and the service provider, and the terms of corresponding agreements are commercially confidential. However, as part of their Code obligations, TNSPs have been required to develop and publish formal negotiating guidelines that apply to such 'negotiable services'. We note that network support agreements may also be entered into at the distribution level of the NEM. Payments to embedded generators may then reflect the avoided cost of network augmentation.

Congestion management

CRA recently developed a proposal for a more market-oriented form of transmission congestion pricing. The proposed regime focuses on points of congestion, and involves specific contracting and localised energy market pricing to create efficient economic incentives within the regional price arrangements. Overall, the purpose of these arrangements would be to integrate incentives for individual generators to enhance the capability of the network with the operations of the spot market.

E.1.3 Inter-Regional Network Support

TNSPs contemplating inter-regional (interconnector) network augmentations must also consider the scope for non-network service provider to avoid significant network investment.

E.2 ONTARIO WHOLESALE MARKET

The Independent Electricity Market Operator (IMO) administers the Ontario electricity wholesale market.[42] The wholesale market clearing price (MCP) is set for each 5-minute interval and reflects bids and offers into the market from dispatchable facilities and boundary entities, and supply and demand from non-dispatchable facilities.[43]

Every five minutes the following real-time market prices are determined:

- MCP for energy across Ontario;
- MCP for energy at each of the twelve intertie zones with neighbouring markets;
- MCP for each of the three operating reserve classes across Ontario.
- MCP for 10 minute non-synchronized and 30 minute operating reserve at each of the twelve intertie zones with neighbouring markets.

Each hour, the Hourly Ontario Energy Price (HOEP) is determined by using the average of the five-minute Ontario energy prices. HOEP is used as the wholesale price for electricity for non-dispatchable generators and non-dispatchable loads.

42 Due to changes incorporated in Bill 100, as of January 10, 2004, the IMO underwent a name change to the Independent Electricity System Operator (IESO).

43 Independent Electricity Market Operator, Market Surveillance Panel, "Monitoring Report on the IMO-Administered Electricity Markets for the period from May 2004 to October 2004", December 13, 2004.

A ten-minute MCP is determined for non-synchronized and 30-minute operating reserve at each of the twelve intertie zones with neighbouring markets. The Hourly Ontario Energy Price (HOEP) is determined on the basis of the five-minute Ontario MCPs.

E.2.1 RMR Contracting Framework

An RMR contract refers to a contract between the IMO and a participant, which allows the IMO to direct the facility to operate in specific ways. The IMO may enter into RMR contracts based on studies that indicate that:[44]

- A facility is required to maintain reliability, not including overall adequacy; and
- Such facility is likely to be dispatched as constrained 'on' or 'off', and such contract would be to the mutual benefit of the Parties.

A contract may be entered into with market participants who have registered facilities capable of supplying or withdrawing physical services.

RMR activations reflect the need for a range of network support requirements, including voltage support, system stability, equipment thermal restrictions, or the management of other *localised* transmission constraints due to a recognised contingency event, where market solutions do not exist. In general, RMR contract terms are for one year. A standardised contract template sets out key contracting provisions.

The IMO may also enter into a RMR contract with a facility that would be temporarily unavailable, if doing so avoids rejection/deferral/recalling of another facilities planned outage. In this situation, the IMO will only pay compensation for 'out-of-pocket' expenses incurred to permit the facility to be available. Facilities that are dispatched under these circumstances will receive no extra compensation above what they are entitled to under normal dispatch payments.

The IMO may call on a RMR resource that is subject to a contract if and only if the IMO determines that market participants will not offer sufficient physical services into real time markets to enable the IMO to maintain reliability, other than in respect of a lack of overall adequacy of the IMO controlled grid.

E.2.2 RMR Contract Negotiations

The IMO uses one or a combination of the following processes to conclude RMR contracts:

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44 Independent Electricity Market Operator, "Summary: Principles of Reliability Must-Run Contracts", July 22, 2002.

- Where practical, a competitive tendering (RFP) or negotiation process to identify multiple potential suppliers and to determine competitive prices and other terms for reliability must run contract; or

- The IMO may negotiate RMR contracts with a single potential supplier (where multiple suppliers do not exist), where the IMO determines that this will result in reasonable prices.

Where the IMO determines, in accordance with any guidelines issued by the Ontario Energy Board (OEB), that the processes noted above will not accomplish a fair and efficient outcome the IMO will:

- Establish and submit for approval from the OEB a standard, cost-based reliability must run contract;

- Contract with the participant in respect to the relevant RMR resource using the RMR contract approved by the OEB as set out above;

- File the contract with the OEB for approval following the conclusion of such contract.

E.2.3 Powers of Direction

In the absence of an RMR contract, the IMO has the authority to direct a registered market participant to submit or to resubmit dispatch data, or both, in order to maintain the reliability of the IMO-controlled grid.

E.2.4 RMR Compensation

A RMR contact template has been established for the purposes of contracting RMR generation.[45] The contract requires the calculation of total estimated costs, including fixed costs (known prior to activation) and an estimate of variable hourly costs and variable energy costs.

Total actual cost will include the fixed costs agreed to and the hourly and energy costs actually incurred by the service provider in respect to the RMR activation. Along with agreed to fixed costs, variable hourly and variable energy costs, total actual cost will include additional labour, condenser/speed no load, related spill, lost opportunity, gas curtailment, non-fuel start-up, or other mutually agreed costs applicable to the RMR activation.

45 Independent Electricity Market Operator, "Reliability Must-Run Contract for Procurement of Physical Services Between "Physical Service Provider" And Independent Electricity Market Operator", Version 01, Nov 29, 2002.

E.3 ELECTRIC RELIABILITY COUNCIL OF TEXAS (ERCOT)

The Electric Reliability Council Of Texas (ERCOT) operates a single control area with regulatory oversight by the Public Utility Commission of Texas (PUCT).[46] The ERCOT wholesale market is designed around bilateral transactions. Wholesale market prices are determined as locational marginal energy prices for generation resources, and zonal energy prices for loads.[47]

Congestion management then distinguishes between interzonal and local congestion:

- *Interzonal congestion management*: The ERCOT market comprises five zones interconnected by transmission interfaces referred to as commercially significant constraints (CSCs). Flows over CSCs are managed by deploying balancing energy in each zone through the balancing energy market.

- *Local congestion management*: Constraints that are not defined as a CSC result in 'local congestion' when they are binding. Local congestion is managed through the redispatch of individual generating or load resources.

In particular the actions that can be taken by ERCOT to manage local congestion include:

- Redispatching specific units out-of-merit order, referred to as out-of-merit energy (OOME);

- Manually committing a resource out-of-market that will help relieve the local congestion, known as out-of-merit capacity (OOMC); and

- Committing or dispatching an RMR resource.

ERCOT only operates a real-time balancing market to address the energy imbalances that result from differences between the real time system requirements and the system loading anticipated in the balanced schedules. The ERCOT balancing energy market is an ancillary service market – not a spot market, and accounts for only 5-10% of the total ERCOT energy market.

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46 Sam R. Jones, P.E., Chief Operating Officer, ERCOT, "The New Texas Wholesale/Retail Market", January 23, 2002".

47 Market Rules, Chapter 25. Substantive Rules Applicable To Electric Service Providers, Subchapter S. Wholesale Markets.

E.3.1 RMR Service

RMR services can be for the provision of generation capacity and/or energy resources from an RMR unit (or a synchronous condenser unit). An RMR unit is a generation resource unit operated under the terms of an annual agreement with ERCOT that would not otherwise be operated except that they are necessary to provide voltage support, stability or management of localised transmission constraints under first contingency criteria where market solutions do not exist.

E.3.2 RMR Contracting Arrangements

RMR services are purchased by the ERCOT ISO, and costs are assigned to Load Serving Entities (LSEs) on a load ratio share basis. RMR agreements are in a standard form, and ISO Staff can enter into RMR contracts without a requirement for additional approval from the ERCOT Board of Directors or from any regulatory body.

ISO Staff are required to develop a list of 'exit strategies' for each RMR contract. To date, these have only included transmission solutions. There is work underway on defining a procedure for contracting with 'Must Run Alternatives' (MRAs), non-transmission alternatives to the RMR contract. It is envisioned that ERCOT would issue pure competitive RFPs for MRAs, and that the compensation would be case specific and approved by ERCOT staff, with input from several Stakeholder Committees. The ERCOT Board is not expected to be in a position to approve these contracts due to anti-trust issues (this is a Stakeholder Board).

E.3.3 RMR Guidelines

Chapter 25, s.(f) of the Substantive Rules Applicable To Electric Service Providers also comments on RMR resources. RMR resources must notify ERCOT if these intend to cease or suspend operation. In the event of a dispute preventing an RMR agreement from being signed, the generation entity may file a complaint with the PUCT against ERCOT. The scope of the complaint may include:

- The need for the RMR service;
- The reasonable compensation and other terms for the RMR service;
- The length of the RMR service, including any appropriate RMR exit options; and
- Any other issue pertaining to the RMR service.

E.3.4 RMR Compensation

RMR compensation reflects variable operating cost, plus a 10% 'adder' on non-fuel costs. When the unit is committed by the ISO, it can sell excess power into the balancing market and retain a portion of the profit from these sales. The unit may not self-commit.

In this context 'variable cost' refers to any cost that would not be incurred if the unit were shutdown or mothballed. This includes fuel and O&M, and capital improvements costs, if these are needed to enable the unit to provide RMR service.

E.3.5 Dispute Resolution

There is currently a 90 day negotiating period between the RMR supplier and the ISO. If an agreement is not reached after 90 days, the generation unit may shutdown or cease operations. The Public Utility Commission of Texas, as the regulator, has proposed a rule to close this existing loophole, which is considered a potential threat to system reliability. Under the proposed rule, the parties would come before the Commission for resolution of the issues, and during that time, the unit must stay available for use by the ISO

E.4 Pennsylvania-New Jersey-Maryland Interconnection (PJM)

The PJM market is composed of two capacity credits markets (daily and long-term) and two energy markets (day-ahead and real time). The day-ahead market is a scheduled market supported by bilateral transactions, while the real time market is a balancing spot market. PJM uses locational marginal pricing (LMP) to value energy along with congestion. PJM also uses a financial transmission rights (FTRs) market to permit participants to hedge against congestion, along with annual revenue rights (ARRs).

In May 2004, the Federal Energy and Regulatory Commission (FERC) ruled on PJM tariff matters as they relate to the compensation of RMR units.[48] In this order, FERC considered the proposed provisions developed by the PJM Interconnection, and announced a general "Reliability Compensation" policy. The order addresses both the specifics of PJM's compensation and dispute resolution process, and the broad principles for TMR compensation.

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48 Order on Tariff Filing, May 6 2004, Docket #: EL03-236-000.

E.4.1 PJM Operating Agreement (6.4.1)[49]

The PJM Operating Agreement (OA), Schedule 1, Section 6, defines a "Must-Run for Reliability Unit" as is "any generation resource subject to the dispatch of the Office of the Interconnection that (a) is a generation resource for which construction commenced before July 9, 1996, and (b) as a result of transmission constraints, the Office of the Interconnection determines, in the exercise of Good Utility Practice, must be run in order to maintain the reliability of service in the PJM Control Area and PJM West Region."

A unit may be selected for "Must-Run" for reliability and cost-capped at any time. All units must submit at least one cost-based schedule in the day a-head market to be used by PJM if the unit must be cost-capped due to a transmission constraint. PJM selects the cost capped units based on the most cost-effective solution to the problem based on the provided cost schedules.

PJM currently has no "Must-Run" for Reliability contracts and no plans to enter into contracts outside the PJM Operating Agreement. Any unit which is bid into the PJM market is eligible to be selected as an RMR unit.

Pricing

The bids of generation resources dispatched out of economic merit to maintain reliability are capped in order to 'restrain the exercise of local market power.' Bids are capped, either during each hour when the transmission limit affects the schedule, or for the entire operating day. These generators then receive a price equal to the greater of the capped bid or the LMP.

Offer price caps are suspended for any transmission limit(s) whenever there are three or more generation suppliers available for redispatch that are not jointly pivotal with respect to such transmission limit(s), unless the Market Monitoring Unit determines that a reasonable level of competition does not exist.

The offer price cap is set as follows:

(i) The weighted average LMP at the generation bus where energy from the capped resource was delivered when it was operating in merit and when the price was deemed to be "competitive";

(ii) The incremental operating cost of the generation resource, plus 10% of such costs; or

(iii) An amount determined by agreement between the Office of the Interconnection and the Market Seller.

49 PJM Interconnection, L.L.C. Substitute Original Sheet No. 131A, Third Revised Rate Schedule FERC No. 24 Superseding Original Sheet No. 131A, Issued By: Craig Glazer Effective: June 1, 2004, Vice President, Government Policy, Issued On: July 16, 2004.

PJM's cost development guidelines comment in great detail on the calculation of capped costs:[50]

- Incremental heat (or fuel) input costs;
- No-load costs;
- Performance factors;
- Fuel costs;
- Operating and maintenance costs;
- Start-up costs;
- Opportunity costs; and
- Regulation costs.

E.4.2 FERC Review

Following a dispute with Reliant, PJM was asked by FERC to review cost recovery for RMR units. While FERC did not find for the applicant, it noted that PJM itself had recognized that its current provisions may not have been the most appropriate mechanism for ensuring cost recovery for RMR units, particularly as they relate to scarcity pricing. FERC stated that the issue a of long term solution to RMR cost recovery was of sufficient importance to warrant a quick resolution, and found that:

- PJM should re-examine its mechanism to ensure that it was providing appropriate compensation while mitigating market power for RMR services;
- Specifically, PJM should consider whether its current market design, including mitigation measures, were just and reasonable (under the Federal Power Act (FPA)), and whether there were both adequate incentives to attract and retain needed investment as well as provide rates that were not excessive.

In this and other proceedings concerning organised wholesale electric markets, FERC has had to consider appropriate compensation to generators needed for reliability but subject to market power mitigation.

FERC laid out the following principle for analysing reliability based compensation:

50 PJM, "Manual 15, Cost Development Guidelines", Revision: 04, Effective Date: September 01, 2004.

- Market power mitigation (which impacts revenue received by units needed to ensure reliability) can conflict with the longer term goal of attracting and retaining necessary infrastructure to assure long-term reliability in such markets (referred to as Reliability Compensation Issues (RCIs).
- As a result, FERC determined that there is not necessarily a standard regulatory response to such issues. FERC therefore determined that it would employ an "overarching analytical approach" which will institute a consistent and disciplined way of looking at these issues. "The right path to solve Reliability Compensation Issues should be both uniform and transparent."

FERC then outlined the following analytical approach to address RMR compensation issues:

6. Determine whether the market exhibits material short term or long term Reliability Compensation Issues (RCIs).
    a. Short term issues relate principally to appropriate compensation for units needed for reliability and are subject to mitigation with the result that the units are receiving non-compensatory revenue impacting the ability to provide the service.
    b. Long term issues relate to local capacity shortages identified in the reliability based planning process resulting from the reasonably expected retirement of units or need for new infrastructure that is not anticipated to be installed.
7. If material RCIs exist, evaluate whether market design improvements can be implemented to resolve issues. If material RCIs do not exist, targeted approaches (such as unit specific contracts or compensation schemes) may be appropriate.
8. In undertaking analysis, specific RCIs should be reviewed and market design changes targeted for resolution. If either LR-RCIs or SR-RCIs are identified, there should be the demonstration that the solution proposed is feasible, implementible and expected (with high probability) to solve the problem. Such demonstration must include showing the revenue produced by the solution is adequate to solve the problem and safeguard against the exercise of market power.
9. The value of the service should be apparent to both the buyer and the seller. Market design feature that can work as solutions include:
    - Locational changes such as locational installed capacity (LICAP markets);
    - Locational operating reserves;

- Locational pricing for energy in time of locational operating reserve scarcity; and
- Higher bid-caps or relaxed mitigation (increased reference prices, proxy unit based approaches, increased offer caps) or other approaches designed to solve RCIs while protecting against the unwarranted exercise of market power.

10. While market design changes are the preferred choice for solving RCIs, market design changes may not be effective in every situation. If market design changes are or will be ineffective, other mechanisms should be utilized. FERC is willing to consider specific proposals to provide appropriate last resort processes such as an RTO/ISO administered auction/RFP to create a long term commitment. Short term remedies such as generator specific contracts may also be appropriate. These approaches should be viewed as a backstop to market design based solutions. FERC expressed concern that when an RTO/ISO negotiates contracts to procure power, it may assume an interest in market prices which could sacrifice its independence and change its incentives. RTO/ISO auctions/RFPs are therefore not substitutes for market design based solutions, and should only be invoked when there is an affirmative finding that market design solutions will not effectively solve the problem.

11. In implementing RTO/ISO based backstops, the rules should provide for a clear triggering event that authorizes the RTO/ISO to act. Such triggering events should reflect findings that market design options are inappropriate and an auction/RFP is the most effective vehicle for creating a solution. Payment obligations resulting from an auction/RFP should be allocated to the local load benefiting from the reliability improvement. The analytical process resulting in the auction/RFP process should be transparent, include material stakeholder input and attempt to create a consensus of market participants, most importantly market participants in the reliability impacted area.

E.4.3 PJM Findings

Although FERC did not find in favour of Reliant, the Commission did identify concerns with PJMs treatment of must-run compensation. FERC found:

- PJMs existing tariff provisions to be unjust and unreasonable for units that are used a high percentage of the time to support reliability with high marginal costs that may not be recovered under the current mitigation scheme. "A frequently mitigated unit may set the market price in many periods when it is dispatched and during these periods it will only receive incremental costs + 10%, which might not be sufficient to enable recovery of its fixed costs over the long run." Frequently mitigated units do not have the right to alternative compensation that would allow them to recover their going forward costs, at the minimum.

- The negotiation process to be unjust and unreasonable because the tariff allowed for negotiation between the generator and PJM, but the negotiation was at the discretion of PJM. As such the tariff did not provide the generator with a clear statement of its rights if an agreement could not be negotiated.

  FERC subsequently directed PJM to revise its tariff to provide the right to frequently mitigated units needed for reliability (i.e. units that are offer capped more than 80% or more of their run hours, are needed for reliability, and are not recovering sufficient revenues to cover their costs) to receive higher offer caps or alternative compensation.

- FERC also found that the PJM tariff did not provide sufficient ability to resolve disputes relating to compensation for these units. It directed that:

  - These issues should be covered at the outset by through bilateral negotiations (with a clear expression of the rights of both parties);

  - PJM should file any agreements reached with FERC; and

  - After allowing time for negotiations (60 days), any unresolved issues should be brought before FERC for resolution.

  PJM was also ordered to clarify its policy on retirement of RMR units and compensation if the unit is required to stay in service for reliability.

E.5 Independent System Operator New England (NEISO)

The NEISO uses a zonal system with multi-part settlement and LMPs, along with Financial Transmission Rights (FTR) and Auction Revenue Rights (ARRs) to manage congestion.[51] The New England transmission system is divided into eight pricing zones and a hub, where the LMP for each zone is the load-weighted average of each of the nodal LMPs that make up the zone. The LMP for the hub is the simple average LMP from each of the LMP nodes that make up the hub.

The bulk of electricity trading activity is done through bilateral transactions between wholesale buyers and sellers. Short-term trades are undertaken in the day-ahead and real-time markets.

51 ISO New England, "Wholesale Electricity Trading", May 2003.

E.5.1 Daily RMR Resources

The NEISO identifies "Daily RMR Resources" on a daily basis as necessary for the provision of operating reserve requirements and adherence to NERC, NPCC and NEPOOL reliability criteria over and above those resources required to meet first contingency reliability criteria within a reliability region.[52]

When establishing operating schedules, the NEISO will select daily RMR resources on a not unduly discriminatory basis in accordance with the procedures defined in the NEPOOL Manuals. RMR payment for daily RMR resources is based on the highest of:

- the LMP for the hour;
- the lower of the supply offer or the applicable reference level; or
- the resource's 'stipulated bid cost'.

E.5.2 Contractual Arrangements

NEISO has identified Designated Congestion Areas (DCAs) based on an evaluation of historic operations patterns in North East Pool Control Area (NEPOOL) and forecast requirements for maintaining reliability. These are geographic areas in which resources owned by a limited number of suppliers are regularly required to be run to relieve transmission constraints.

Entities designated as an RMR resources may apply to the ISO for an RMR agreement (pro forma contract). The request includes one of the following four options for a RMR agreement that the RMR seller believes is appropriate for its resource:

- Option 1: Prospective agreement based on marginal cost, including a wear and tear adder;
- Option 2: Prospective agreement for limited energy resources;
- Option 3: Prospective agreement to avoid a seasonal shut-down or other capability-reducing action, using an avoided cost adder; and
- Option 4: Prospective agreements to avoid a seasonal shut-down or other capability-reducing action, with a hold-harmless payment subject to true-up.

52 New England Power Pool, "Market Rule 1 - NEPOOL Standard Market Design".

E.5.3 PUSH Offer Rules

On June 1, 2003, the ISO implemented Peaking Unit Safe Harbor (PUSH) offer rules.[53] These allowed owners of low capacity-factor units (less than 10% annual capacity factor) in DCAs to include levelised fixed costs in their supply offers without risk of mitigation. The rule change was intended to enable fixed cost recovery and to produce signals for investment through higher LMPs in these areas during periods of scarcity.

Stipulated Costs

Stipulated costs are determined using the generating unit fuel usage and related items for the applicable operating day including incremental energy bids and start-up and no-load values. Hence:

Stipulated Marginal Cost (SMC)

= Incremental Operating Cost

\+ Wear & Tear Adder

\+ Avoided Costs Adder (if applicable) or Lost Opportunity Cost (if applicable)

Where:

Incremental Operating Cost = (Fuel costs + O&M costs + Other costs) * MWh

Fuel costs = (Variable fuel use for generation * Fuel index price) + Fuel cost ancillaries

O&M costs = Variable O&M as specified in the RMR Agreement

Other costs = SO_2 allowance adder + NO_x allowance adder + Operating permit adder

Wear and tear adder = Incremental operating costs * 0.10

53 ISO New England, "A Review of Peaking Unit Safe Harbor (PUSH), Implementation and Results", December 3 2003.

Avoided Costs

The avoided costs adder is intended to ensure the availability of a resource where it is in the economic interest of the RMR seller to shut down for part of the year or take other actions that would reduce the capability or availability of a resource, and where the ISO determines is needed for the reliability and security of the system. RMR sellers seeking an RMR agreement and claiming the avoided costs adder are required to establish that the resource would have shut down for a demonstrable period.

Lost opportunity costs are available only for generating resources that are subject to output limitations that significantly restrict expected in-merit operation. These are negotiated on a case-by-case basis to provide the resource payments intended to approximate the net revenue the resource would have obtained had it operated solely in the market.

E.5.4 Negotiation of Cost of Service Agreements

If the ISO has determined that it requires a particular facility to stay in service for reliability reasons, it may undertake financial arrangements to ensure that the facility will be available. In this case there is opportunity for the RMR seller to be compensated an amount equal to the cost of continuing to operate the resource as RMR. The RMR Seller can file (with FERC) for cost-based rates with each party free to take any position it determines appropriate regarding recovery of return of and on investment.

E.6 CALIFORNIA INDEPENDENT SYSTEM OPERATOR (CAISO)

The CAISO operates a fraction (less than ten percent) of the total wholesale electricity marketplace to maintain operating reserves and match supply with demand. Scheduling Coordinators submit ISO balanced demand and supply schedules. The real-time imbalance market is cleared on a zonal basis.

E.6.1 Planning Processes

The CAISO conducts an annual Local Area Reliability Service (LARS) process to determine which resources it requires to ensure that local areas meet reliability criteria.[54] The ISO Governing Board approves the designation of RMR units. Through an annual planning process, the CAISO designates specific generating units as RMR units, based on the potential need for these units to be on-line and/or generate at sufficient levels to provide voltage support, adequate local generation in the event of system contingencies, and meet other system requirements related to local reliability.

54 California Independent System Operator, Memorandum to ISO Board of Governors from Robert Kott, Manager of Reliability Contracts, Re: RMR Designations for 2005, September 10, 2004.

In addition the LARS process included a solicitation of proposals for load management alternatives, transmission projects and generation resources to meet the forecast of reliability requirements.

E.6.2 RMR Contractual Agreement

The CAISO has the right at any time, based on technical analyses and studies, to designate a generating unit as an RMR unit. Such an RMR unit is then obligated to provide the ISO with its proposed rates for RMR generation for negotiation with the CAISO. Such rates are authorized by FERC or the Local Regulatory Authority, whichever authority is applicable.

The RMR contract is intended to allow the ISO to maintain reliability and curb the market power of units needed to maintain local area reliability by giving the ISO the ability to call on these units in real time at cost-based prices. RMR contracts provide a mechanism for compensating unit owners for the costs of operating when units are needed for local reliability, but may not be economical to operate based on overall energy and ancillary service market prices.

The pro forma agreement developed by the CAISO sets out key terms and conditions for RMR resources:[55]

- The CAISO may issue RMR dispatch notices whenever market bids cannot be used to manage congestion without taking a bid out of merit order; and
- RMR units must elect to provide service under one of two ‘conditions’:
  - A Unit under Condition 1 may participate in market transactions and retain all corresponding revenues; or
  - A Unit under Condition 2 is dispatched by the CAISO and may not retain revenues from market transactions.

E.6.3 RMR Compensation

The payment of RMR units is complex and is dependent on the nature of the RMR contract. RMR units receive an annual fixed payment from the CAISO for various interrelated reliability needs, as well as separate monthly payments for their operational or variable costs. Payment options are set out in a pro forma contract, which outlines the calculation for the annual fixed revenue requirement and monthly payments.

In addition, RMR units are able to collect a fixed option payment, to be negotiated between the RMR unit owner, the applicable Participant Transmission Owner, and the ISO.

55 California Independent System Operator, “Pro Forma Must-Run Service Agreement ”.

E.6.4 Dispute Resolution

If bilateral negotiations fail to resolve contract issues, CAISO has in place an alternative dispute resolution (ADR) process. However, nothing in the RMR agreement affects an owner's right to unilaterally make application to FERC for a change in rates or terms and conditions under Section 205 of the Federal Power Act and pursuant to FERC rules and regulations. The CAISO may also challenge such application or may submit a complaint concerning the RMR owner's rates, terms and conditions under s.205 of the FPA.

APPENDIX F: ABOUT THE AUTHORS

The project was led by **Mr Gregory Thorpe**, Vice President of CRA, based in Melbourne, Australia. He is in his 30th year in the electric power industry spanning both the central utility and competitive market eras. He provides consulting advice to Australian and international clients on a diverse range of market design, governance and regulatory matters. Previously he was an Associate Director of the National Electricity Code Administrator (Australia) during its formation and the initial years of operation of the Australian National Electricity Market (NEM)

He established and managed the market surveillance function for the Australian electricity market. He is an experienced power system engineer and has managed central operations associated with dispatch and operational planning and designed high voltage networks within a vertically integrated utility. Mr Thorpe has also served as the executive officer for the Reliability Panel for the NEM

Dr Lewis Evans - Senior Consultant to CRA and Professor of Economics, Victoria University of Wellington (New Zealand) provided key economic review. Dr Evans specializes in the economics of organizations and markets. He has published more than 35 refereed articles in leading international and local economics journals and has another 50 publications. He is a member of the editorial boards of *the Journal of Economic Literature*, and *Contemporary Economic Policy*. He is a lay member of the New Zealand High Court for matters of commerce and a member of the Electricity Market Surveillance Committee. He has consulted for a considerable number of companies and governmental organizations, including the Asian Development Bank and the RAND Corporation, a private policy institution in Los Angeles. In 1996, he was awarded the NZIER-Qantas economics award.

Ms Sabine Schnittger, Principal, played a major role in developing economic analysis and drafting of this report. Based in Melbourne, is a highly experienced economist with extensive international experience in restructuring, and design and regulatory issues arising in utilities industries and associated markets. She has provided economic advice to private and public sector clients in the US, the Asia Pacific region, and in Europe. In the utilities sector, Ms Schnittger has advised on regulatory matters arising in the course of the reform and privatisation of the UK utilities industries. She has advised a wide range of clients in the Australian National Electricity Market (NEM), and market design and regulatory issues in the US, Canadian and European energy markets.