Alberta Energy and Utilities Board

DECISION 2001-13

ESBI ALBERTA LTD.

PART D: LOCATION BASED CREDITS – STANDING OFFER FIRST REFILING PURSUANT TO DECISION 2000-76

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ALBERTA ENERGY AND UTILITIES BOARD
Calgary, Alberta

ESBI ALBERTA LTD. — **Decision 2001-13**
PART D: LOCATION BASED CREDITS – STANDING OFFER — **Application No. 990005**
FIRST REFILING PURSUANT TO DECISION 2000-76 — **File No. 1803-6**

1 INTRODUCTION AND BACKGROUND

In Decision 2000-1, the Board directed ESBI Alberta Ltd. (EAL) to develop a Standing Offer process to incent generation solutions to transmission constraints on an ongoing basis. In a refiling dated September 29, 2000 EAL proposed the Location Based Credits Standing Offer (LBC SO) process. In addition to requesting approval of the process format EAL also requested approval to launch Standing Offers to incent generation in the southern Alberta, Lloydminster, and Grande Prairie areas.

On October 17, 2000 the Board issued notice that a hearing would be held to consider the matters raised by the parties. A public hearing was held in Calgary, Alberta on November 9 through to November 15, 2000 with N. W. MacDonald, P. Eng., A. J. Berg, P. Eng., and R. G. Lock, P. Eng. sitting. Written arguments from the parties were received on or about November 17, 2000 and written reply received on or about November 22, 2000.

On December 14, 2000, the Board issued Decision 2000-76 directing EAL to refile the LBC SO contract and procedures to comply with findings and directions of the Board.

On January 22, 2001, EAL submitted a refiling of the Location Based Credit - Standing Offer Process (LBC SO) in response to the Board's directions in Decision 2000-76 issued December 14, 2000.

On January 25, 2001, EAL submitted an explanatory memorandum that was intended to form Tab 3 of the refiling. Accordingly, the complete refiling was organized as follows:

- Tab 1: Response to EUB Directions
- Tab 2: Location-Based Credit Entitlement Offer
- Tab 3: Explanatory Memorandum

The Board received detailed comments from FIRM, the Coalition, and TCE. Calpine, Duke and ENMAX did not submit detailed comments but did submit correspondence. Calpine indicated that it had participated in the development of the comments, and supported the Coalition comments respecting certain contractual matters raised by the terms and conditions of the Location-Based Credit Entitlement Offer. Duke submitted comments supplemental to its participation in the Coalition.

EAL convened a meeting on February 8, 2001 to discuss Intervenor comments. As a result of this meeting, EAL proposed further changes to the LBC Entitlement Offer in a document entitled "Appendix A: Location based Credits Standing Offer – Negotiated Settlement February 8, 2001". This document is attached as Appendix 2 to this Decision.

On February 12, 2001, EAL filed a revised LBC Entitlement Offer that reflected the results of discussions with Parties.

Parties submitted comments with respect to EAL's revised LBC Entitlement Offer on February 13, 2001. EAL responded by way of final reply on February 16, 2001.

ENMAX reiterated that it strongly advocated the urgent need to address the increasing risk of a rapid system voltage collapse in southern Alberta and, in particular, the Calgary area. In recognition of this need, ENMAX urged the Board to approve EAL's Refiling as soon as possible.

The Board has reviewed EAL's responses to the Board's Directions and the Board provides its decision herein.

The Board has also reviewed the February 12, 2001 revised LBC Entitlement Offer and notes that there are outstanding issues that need to be resolved by the Board prior to the Board's final approval of the LBC SO process and LBC Entitlement Offer:

The following sections of this Decision address these outstanding issues. Each issue section contains Views of the Parties and Views of the Board.

2. Incentive Payments
3. Eligibility Payments
4. Supplemental Payments
5. Definition of Forced Outage – Adjustment for De-rating
6. Cure Periods
7. Covenants
8. Definition of Forced Outage-Good Electric Operating Practice
9. Approvals
10. Audit Provisions
11. Definition of Dispatch
12. Total Requested Hours
13. Acceptance in Multiple Zones
14. Liquidated Damages in Event of Default
15. Liability
16. Transmission Development Plan

Section 17 provides details of the Board's direction to EAL to make a second refiling to comply with findings and directions of the Board in this Decision.

Section 18 summarizes the directions of the Board in this Decision for the convenience of readers.

The comments and views of the Parties in this Decision for the most part reflect the latest views of the parties after the revised filing by EAL on February 12, 2001. However, where appropriate earlier views of Parties are included.

A complete summary of the Views of Parties is included as Appendix 1. Appendix 2 is the February 8, 2001 submission by EAL representing results of discussions between parties on issues.

As a result of this Decision, the Board requires EAL to submit a second refiling.

2 INCENTIVE PAYMENTS (Article 4.1(f) and 4.1(b))

EAL proposed the following wording for Article 4.1(f) of the LBC Entitlement Offer:

> In the event that the COD is achieved before the RCOD, the Generating Facility Owner shall be entitled to twice the amount of the LBC Rate as determined pursuant to the scale set out under *Section 4.1(b)* (the **"Incentive LBC Rate"**) and the Incentive LBC Rate shall be paid by the Transmission Administrator for the period commencing on the date that the Facility achieved COD and ending on midnight of the day immediately preceding the RCOD in accordance with *Article12.* The Monthly Incentive LBC Payment shall be calculated based on the sum of the Target Hourly Energy multiplied by the Incentive LBC Rate (the **"Monthly Incentive LBC Payment"**). No more than six (6) consecutive months of the Monthly Incentive LBC Payment will be paid by the Transmission Administrator to the Generating Facility Owner in respect of any Facility and the Generating Facility Owner shall not be entitled to receive the Monthly LBC Payment while receiving the Monthly Incentive LBC Payment.

Article 4.1(b) was proposed by EAL to read as follows:

> (a) Subject to this and any early termination of this Agreement, commencing on the RCOD for each Tranche of Credit Capacity (provided that the COD for each Tranche of Credit Capacity occurs on or before the applicable RCOD, if the COD occurs after the applicable RCOD then the Monthly LBC Payment shall not commence until the COD) and terminating on the 20th anniversary of each such RCOD, the Generating Facility Owner shall be entitled each Month to, and shall be credited or paid by the Transmission Administrator, the Monthly LBC Payment applicable to such Month based upon that portion of the LBC Rate, determined as follows*:*
>
> (i) 100% of the LBC Rate if the Facility has an Energy Ratio of $\geq 95\%$;

(ii) 90% of the LBC Rate if the Facility has an Energy Ratio of < 95% but ≥ 85%;

(iii) 80% of the LBC Rate if the Facility has an Energy Ratio of < 85% but ≥ 70%; or

(iv) 0% of the LBC Rate if the Facility has an Energy Ratio < 70%;

(v) where:

(A) **"Energy Ratio"** means the ratio (expressed as a percentage) of the sum of the Target Hourly Energy in the Month, to the Target Monthly Energy;

(B) **"Target Monthly Energy"** means the Credit Capacity in Commercial Operation multiplied by the Target Hours;

(C) **"Target Hourly Energy"** means, during hours in which the Facility is Dispatched, the lesser of the Metered Energy at the metering point set out in *Section 4.1(a)* in the hour or the product of the Credit Capacity in Commercial Operation and one hour; and

(D) **"Target Hours"** means the difference between the total hours in a Month for which the Facility is Dispatched and the total number of hours for which there was a Permitted Unavailability or an occurrence of Force Majeure during the said hours the Facility was Dispatched.

Views of TCE

TCE supported the addition of an Incentive LBC Rate, as set out in the Board's Decision 2000-76 at p. 92, "Eligibility for incentive payments for generation being in operation of the required date up to 6 months early, similar to the IBOC contract".

In reviewing section 4.1(f) of EAL's refiling, it appeared to TCE that this provision would result in Incentive Payments being made in accordance with section 4.1(b) in that the Incentive Payment could be reduced based on the Energy Ratio (if less than 95%).

TCE submitted that the incentive payment under Section 4.1(f) of the pro-forma contract should not be determined pursuant to the scale set out under Section 4.1(b). TCE submitted that removing the wording "as determined pursuant to the scale set out under Section 4.1(b)" would resolve this issue.

Views of EAL

EAL disagreed with TCE because in EAL's view it is appropriate that the Generating Facility Owner (GFO) meet the performance requirements in order to receive payment. The performance requirements set out in Section 4.1(b) (sliding scale payments formula) should be applicable for all hours that the Facility receives a Dispatch Instruction, regardless of whether this is after the RCOD or before it (in the case of early COD).

Views of the Board

The Board concurs with EAL that the GFO should be required to meet performance standards in order to receive incentive payments.

Accordingly, no change is necessary to EAL's proposal respecting the requirement to meet performance standards in order to receive incentive payments.

3 ELIGIBILITY PAYMENTS

EAL proposed an incentive payment of 2 times the LBC SO Rate for each hour that the generator is in operation ahead of the Required Commercial Operation Date (RCOD) for a period of up to 6 months. Conversely, if the generator is late in achieving commercial operation an eligibility payment or penalty of $50 per day per MW of credit capacity was proposed for a period of up to 6 months. EAL indicated this approach was similar to IBOC payments.

Views of FIRM

The FIRM Customers noted there is not symmetry around the RCOD for proposed payments/receipts. For an assumed LBC SO Rate of $5/MWh. the incentive for early completion would be $10/MWh whereas the eligibility or penalty rate for missing the contract date would be a much lessor amount of $2.08/MWh ($50/24 hrs). For equivalency, the eligibility payment would have to be in the order of $120 per day per MW for the assumed LBC SO Rate. Furthermore, as the LBC SO Rate increases, the disparity between incentive and penalty payments increase.

Therefore the FIRM Customers recommended there be closer symmetry between the incentive and penalty provisions by increasing the daily eligibility payment (i.e. by assuming an LBC Rate or using the average of the existing IBOC Rates for calculation purposes) or using the same 2 times the LBC SO Rate formula.

Views of EAL

EAL stated that it had considered making the Eligibility Payment equal to twice the amount of the LBC Rate, as recommended by the FIRM Customers, versus using the same Eligibility Payment provided in the IBOC contracts. EAL considered that the latter was already approved by the Board and provided a sufficient deterrent for missing the RCOD.

EAL noted that making the Eligibility Payment equal to twice the amount of the LBC Rate would not be symmetrical with the Incentive LBC Rate. Using the LBC Rate as the reference point, the Generation Facility Owner (GFO) gains an additional amount equal to the LBC Rate for achieving its COD before the RCOD. On the other side, the net loss to the GFO for missing the RCOD would be equal to a charge of twice the LBC Rate, in addition to the lost opportunity of not receiving the LBC Rate.

Views of the Board

The Board accepts that EAL's approach was logical and reasonable and consistent with IBOC.

However, the Board now agrees with FIRM that there should be closer symmetry between the incentive and penalty provisions set out in Clause 4.1. The Board considers that closer symmetry can be achieved by increasing EAL's proposed eligibility payment or penalty from $50 per day per MW of credit capacity to $120 per day per MW of credit capacity. The Board notes that the $120 per day per MW is approximately equivalent to a notional LBC Rate of $5 per MWh (i.e. $120/24 hours).

The Board notes that closer symmetry is achieved since the GFO would receive an additional amount equal to the LBC Rate for achieving its COD before the RCOD and conversely would be required to pay an amount approximately equal to the LBC Rate for not meeting the RCOD.

The Board directs EAL, in its second refiling, to revise Clause 4.1(e) to increase the proposed eligibility payment or penalty from $50 per day per MW of credit capacity to $120 per day per MW for a period of up to 6 months.

4 SUPPLEMENTAL PAYMENTS

Views of FIRM

The FIRM Customers submitted that the LBC Rate should be included in the Operating Cost Benchmark because it will be an offsetting factor to the GFO's operating costs. Furthermore, the FIRM Customers submitted that if there is a concern that inclusion of the LBC Rate in the Operating Cost Benchmark will cause the GFO's required LBC Rate to be higher, then a business case should be prepared to substantiate this concern.

Views of EAL

EAL confirmed its concern that including the LBC Rate in the Operating Cost Benchmark will cause the GFO's required LBC Rate to be higher. EAL submitted that the logic for this concern is straightforward and does not require a detailed business case.

The number of hours during the 20-year term of the contract for which a GFO expects to receive the LBC Rate payment is a factor that determines the LBC Rate that the GFO will require in order to make its generation project economic. Including the LBC Rate in the Operating Cost Benchmark means that the GFO will effectively forfeit the LBC Rate payment during hours when the pool price is below the benchmark.

The GFO will, therefore, reduce the expected number of hours that it will receive the LBC Rate, causing its required LBC Rate to increase in order to keep its project economic. Due to the high level of uncertainty encountered in forecasting the number of hours over a 20-year period that the pool price will be below the Operating Cost Benchmark, the GFO will build in a risk premium, resulting in a further increase in its required LBC Rate.

EAL noted that this is the same reason that EAL gave to the Board during the LBC SO hearing for the inclusion of the Supplemental Payments. Spreading the risk over the TA's revenue requirements will result in a lower LBC Rate by reducing the GFO's risk premium, which will in turn result in lower overall costs to the TA's customers. The Board accepted this position in its decision, and did not require a detailed business case.

Views of the Board

The Board concurs with EAL that including the LBC Rate in the Operating Cost Benchmark will cause the GFO's required LBC Rate to be higher. Accordingly, the Board considers that no change is required to the Operating Cost Benchmark.

5 DEFINITION OF FORCED OUTAGE – ADJUSTMENT FOR DE-RATING

At the February 8, 2001 meeting, EAL noted that certain Intervenors proposed that the definition of Forced Outage allow for generator de-rates. EAL stated that it does not support such a change because it would significantly increase the burden of administering the contract.

Views of EAL

EAL proposed to accept that a Dispatch Instruction would be deemed to have been satisfied if the output of the Facility exceeds 90% of its Credit Capacity. This provision provides flexibility for de-rates and aligns dispatch requirements with the current Power Pool rules.

Views of ENMAX

ENMAX supported EAL's proposal, namely that EAL will accept that a Dispatch Instruction is satisfied if the output of the Facility exceeds 90% of its Credit Capacity and submits that this proposal is reasonable and provides adequate flexibility to account for de-rates.

Views of FIRM

The FIRM Customers supported EAL's position on this issue.

Views of the Board

The Board accepts EAL's proposal that a Dispatch Instruction would be deemed to have been satisfied if the output of the Facility exceeds 90% of its Credit Capacity. The Board considers that this proposal will provide adequate flexibility to account for de-rates.

6 CURE PERIOD

Another proposal arose from the February 8, 2001 meeting due to the increasingly tight time requirement to meet the RCOD. The issue was that the generator should be allowed to trigger Cure Periods within 24 months from the date of an Acceptance without having them count against the aggregate Cure Period limit of 365 days. (The 24 months represents construction time.) EAL considers this provision to be unnecessary, as there is already sufficient flexibility around Cure Periods.

Views of ENMAX

ENMAX agrees that LBC SO generators ought to be allowed to trigger Cure Periods within 24 months from the date of an Acceptance without such period counting against the aggregate Cure Period limit of 365 days or the allowed number of Cure Periods.

This proposal will provide an incentive to EAL to ensure the earliest possible Acceptance date in order to ensure that the 24 month grace period begins to run as soon as possible. In turn, this will also ensure that generators have the maximum amount of time between the Acceptance date and the Required Commercial Operation Date ("RCOD").

Views of FIRM

The FIRM Customers have some sympathy for the generators' concern as the LBC SO process timetable has extended further than initially anticipated. With an LBC SO initiation in March this would be some 4 months short of 24 months for RCOD of December 2002. With the flexibility around Cure Periods allowing the generator to trigger within 22 months appears to be an appropriate compromise in the circumstances. The FIRM Customers consider this period would provide the generator sufficient incentive to meet the target date and potentially allow more participants into the LBC SO process.

Views of EAL

EAL noted in its comments of February 16, 2001 that the Coalition [§8] expresses concern over the Cure Period provisions. These provisions are intended to address catastrophic failures that would be expected to occur only once or twice in the commercial life of a generator. Given that an LBC SO generator must have a high level of reliability over the 20-year contract term in order to be a substitute for transmission, EAL believes that the Cure Period provisions are already generous. The Coalition's concern about early problems is amply addressed by starting to count the number of Cure Periods six months after the COD.

Views of the Board

The Board considers that EAL's clarification as stated on February 16, 2001 is important and represents a reasonable approach by not counting the number of Cure Periods until 6 months after COD.

The Board considers the contract language in the Offer does not communicate EAL's intent clearly.

In the absence of EAL's clarification, the Board would have agreed with ENMAX, FIRM and the Coalition that a relaxation is warranted. A relaxation is warranted to allow LBC SO generators to trigger Cure Periods from the date of an Acceptance without such period counting against the aggregate Cure Period limit of 365 days or the allowed number of Cure Periods.

The Board considers that this clarification provides a balanced approach.

The Board directs EAL, in a second refiling, to incorporate its intent as stated in its February 16, 2001 clarification by starting to count the number of Cure Periods six months after the COD. The clarification should clearly identify the impact on both the number of Cure Periods and against the aggregate Cure Period limit of 365 days. The Board assumes that EAL intended the six month period not to count against the aggregate Cure Period limit of 365 days as well.

7 COVENANTS

7.1 Section 3.1(c) – Timing of Document Provisions

Views of the Coalition

The Coalition stated that the provision required the Generating Facility Owner (the "GFO") to provide the Transmission Administrator (the "TA") with a series of documents within a very short time period following the Acceptance Date. In the case of a Facility that has an RCOD of less than two years following the Acceptance Date, the period for providing these documents was 25 Business Days. In many instances, obtaining these documents within such a short period of time is not relevant to the Construction Schedule or otherwise on the critical path to the achievement of COD prior to RCOD. In other instances, it is not clear what is intended. Specifically, 3.1c(i) should be amended so that "letters of intent" was used. The Coalition recommends that 3.1c(vii) should be amended to delete reference to "and operation". 3.1c(viii) should be amended to delete reference to "and maintenance". The Coalition also suggested that a clause should be added at the end of 3.1(c). This clause would indicate that failure by the GFO to provide documentation within the 25 days specified could not be used as an Event of Default unless the TA considered it likely to cause a delay in the RCOD.

Views of EAL

EAL provided comments in its February 16, 2001 letter to the Board. EAL notes that the Coalition takes issue with Subsection 3.1(c) of the contract but that this section was filed with the Board, as part of EAL's LBC SO application in September. EAL considers that this application was debated during the hearing and that the Board in Decision 2000-76 approved it. EAL noted that these issues were not raised by the Coalition in written comments filed with Board on January 31, 2001 and were not mentioned by the Coalition in the meeting that EAL held with the Coalition, FIRM Customers, ENMAX, and others on February 8. These comments should be dismissed.

Views of the Board

The Board agrees with EAL that these issues should have been raised earlier by the Coalition. However, the Board notes these issues were not debated during the Hearing.

Nonetheless, the Board considers that the Coalition makes valid arguments in many situations. The Board considers that its determinations in some situations may be beneficial to GFOs and in other cases may result in increased ability for the EAL to achieve its objectives. On balance, the Board considers that a more fair and reasonable outcome will have been achieved.

Accordingly, the Board will consider and address the concerns raised by the Coalition. The Board in this section will provide its views.

The following is a summary of the Board's findings with respect to Section 3.1:

- Generally speaking, the Board agrees a letter of intent is not binding but rather an expression of intent. However, in this case it is provided as an alternative to an executed agreement. The Board agrees with EAL as to its use of binding letter of intent and considers that no change is required.

- The Board agrees with the Coalition that the need for insurance for "operation" seems unnecessary within 25 Business Days following the Acceptance Date.

  Accordingly, the Board agrees that in subsection 3.1(c)(vii) the phrase: "and operation" in the context of 25 days should be deleted.

  Rather, the Board considers that a provision should be added that the demonstration of insurance for operation must be provided 180 days prior to RCOD.

  The Board further considers that a provision should be added to provide an obligation for the GFO to provide proof of adequate insurance to the TA on an annual basis.

- The Board agrees with the Coalition that subsection 3.1(c)(viii) should be amended to delete the phrase: "and maintenance".

  Rather, the Board considers that a substitute clause should be added to the effect that no later than 180 days prior to the RCOD, the GFO must provide either a maintenance contract or an affidavit of self-provision. This affidavit would certify that the GFO will be maintaining the Facility using its own employees and therefore will not need to enter into such a maintenance agreement.

  If the GFO should decide at any time during the Term that it will issue a maintenance contract to a third party, a provision should be added to require the GFO to file such contract with the TA within 15 days of entering a contract.

  Conversely, should the GFO decide to change from a maintenance contract to a self-provision of maintenance, a provision should require the GFO to provide the affidavit noted above to EAL warranting that it is capable of conducting such activities.

The Board, in the Audit section of this Decision, will also clarify that the TA has audit rights with respect to operations, maintenance records and maintenance plans. These audit rights will exist during the normal course of events and during the TA's assessment of a Recovery Plan.

- The Board agrees with the general intent of the Coalition with respect to the discretion to be provided to the TA in having flexibility to adjust the time frames. The

Board considers that a slightly modified clause to that proposed by the Coalition should be added at the end of subsection 3.1(c) as follows:

> The Transmission Administrator shall, in its sole authority, use its reasonable discretion in requiring receipt of any of the specific documentation referred to in this subsection 3.1(c) by the applicable deadline. The TA shall consider that the failure of the Generating Facility Owner to provide same will, or, in the reasonable opinion of the Transmission Administrator, is likely to cause a delay in the achievement of COD on or before the RCOD. If a deadline is extended for a material item, the TA may require, in its discretion, a deposit from the GFO in the amount of $5000 per MW of credit capacity. This deposit shall be forfeited in the event that COD is not achieved within 6 months of RCOD. This deposit shall be in cash or by a financial instrument acceptable to the TA.

Accordingly, the Board directs EAL, in a second refiling, to make the necessary changes to implement the above views of the Board on Section 3.1(c) on the following issues:

- insurance for operations,
- the securing of maintenance services, and
- the discretionary authority for adjusting deadlines for provision of any necessary document.

7.2 Section 3.1(e)(i) – Interconnection less than 240 kV

Views of the Coalition

The Coalition noted that section 3.1(e)(i) required that if a GFO wished to interconnect to the Transmission System at a voltage lower than 240 kV, it must have the approval of the TA.

On February 1, 2001 the TA advised members of the Coalition that no Acceptance which relied upon a connection at a voltage lower than 240kV could be made unless the TA had previously approved such lower voltage. The Coalition requested that the Board ensure that the TA puts in place a process which allowed for prompt approval of lower voltage connections and thereby ensured all Qualified Persons could participate in the Entitlement Offer Process at its commencement.

Views of EAL

EAL in its submission of February 16, 2001 noted that the Coalition requested that the Board ensure that the Transmission Administrator put in place a process that allows for prompt approval of lower-voltage connections.

EAL advised that its process will review all such requests that are received at least one week before the Standing Offer implementation date. If acceptable to the Transmission Administrator, these requests will be granted. EAL cannot guarantee the evaluation of requests received less than one week before the implementation date.

Views of the Board

The Board appreciates EAL's clarification of its process and considers EAL's practice should address the reasonable concerns of the Coalition. Accordingly the Board does not require any change.

However, in order to provide clarity to all participants, the Board considers that EAL should announce a cut-off date for all requests noting the one-week processing time.

Accordingly, the Board directs EAL to announce a cut-off date for accepting applications for lower-voltage connections associated with the LBC SO process.

7.3 Section 3.1(e)(iv) – Revised Interconnection Points

Views of the Coalition

The Coalition maintained it should be made clear that the TA cannot "accept" an Acceptance and then impose an interconnection point other than that specified in the GFO's filed Schedule 2. Further, the Coalition argued that the Acceptance Date should not be triggered until the TA provides the GFO with written acknowledgement accepting such interconnection point.

Views of EAL

In its submission of February 16, 2001, EAL noted that the Coalition suggests that Section 3.1(e)(iv) of the contract be rewritten to indicate that the Transmission Administrator cannot "impose" an interconnection point on the GFO. EAL noted that this section, too, was filed with the Board, as part of EAL's LBC SO application in September. EAL considers that this issue was debated during the hearing, was approved by the Board in Decision 2000-76, was not raised by the Coalition in written comments filed with Board on January 31, 2001, and was not mentioned in the February 8 meeting. EAL asked that the Coalition's comments be dismissed.

Views of the Board

The Board agrees with EAL that these issues should have been raised earlier by the Coalition. However, the Board notes these issues were not debated during the Hearing.

Although the Board has sympathy with the Coalition concerns, the Board considers that EAL has adequately provided for safeguards for fair and equitable treatment.

The Board also considers that a prudent investor would be aware of the interconnection requirements associated with any proposed site given the substantial capital investment and commitments involved. Further, investors would consult with technical experts familiar with the AIES and with the TA as necessary to understand the cost and timing implications of any particular site before accepting a LBC SO offer from the TA.

The Board considers it unlikely that the TA would "accept" an Acceptance and then impose an interconnection point other than that specified in the GFO's filed Schedule 2 in a material prejudicial manner without recourse for the affected GFO.

Section 3.1(e)(iv), states the following:

> the Facility shall be connected to the System at an interconnection point, as approved in writing by the Transmission Administrator, acting reasonably

The Board notes that Section 10.2 Transmission Administrator Representations and Warranties and in particular Section 10.2(b) states the following:

> the Transmission Administrator has taken all necessary actions to authorize the execution, delivery and performance of the Agreement, including the transactions contemplated herein in accordance with the provisions of the Agreement….

In addition, Section 15 provides for Dispute Resolution including Section 15.3 to apply to the Board in the event of Urgent Disputes.

Given the combined effect of these different sections, the Board considers that the concerns of the Coalition are adequately addressed.

Accordingly, the Board rejects the Coalition request that the Acceptance Date is not triggered until the TA provides the GFO with written acknowledgement accepting such interconnection point.

7.4 Section 3.1(g)(i) – Model Variations and Audit System

Views of the Coalition

Section 3.1(g)(i) required that the Facility be compatible with the TA's Model Validations and Audit System ("MVAS"). It was the Coalition's understanding that the constituents of the MVAS were not static and may be required to change from time to time. The Coalition maintained the costs associated with such changes may not in all instances be fairly borne by the GFO.

Therefore, the Coalition requested that the compatibility obligation of the GFO in respect of the MVAS be altered by rewording subsection 3.1(g)(i) as follows:

> …be compatible with the Transmission Administrator's MVAS as it exists at the date hereof, and shall further use all reasonable commercial efforts to implement any changes in the Transmission Administrator's MVAS as approved from time to time by the AEUB, provided that the costs associated with such changes shall be borne by the Generating Facility Owner only to the extent so directed by the AEUB;

Views of EAL

EAL in its submission of February 16, 2001 noted that the Coalition recommends changing Section 3.1(g)(i) of the contract so that it imposes certain constraints on the Transmission Administrator's requirement that the Facility be compatible with the Model Validations and

Audit System ("MVAS"). For the same reasons set out in EAL's other responses, EAL submitted that the Coalition's comments should be dismissed.

Views of the Board

The Board agrees that the Facility must be compatible with the TA's Model Validations and Audit System ("MVAS"). The Board notes that it is the Coalition's understanding that the constituents of the MVAS are not static and may be required to change from time to time. The costs associated with such changes may not in all instances be fairly borne by the GFO. The Board agrees with the viewpoint of the Coalition as to suggested changes.

Therefore, the Board directs EAL in its second refiling to reword the compatibility obligation in respect of the MVAS be altered in subsection 3.1(g)(i) as follows:

> …be compatible with the Transmission Administrator's MVAS as it exists at the date hereof, and shall further use all reasonable commercial efforts to implement any changes in the Transmission Administrator's MVAS as approved from time to time, provided that the costs associated with such changes shall be borne by the Generating Facility;

The Board recognizes that the Parties have available the Dispute Resolution provisions of Section 15 as necessary.

7.5 Section 3.2 - Maximum Time to Commercial Operation

Views of the Coalition

The Coalition noted that section 3.2 was a new provision inserted by the TA for the purpose of ensuring that a GFO was strongly induced to respond to Dispatch Instructions as promptly as possible.

The Coalition observed that this was an extremely onerous provision which fundamentally altered the balance of risk under the Agreement for any GFO. The impact of this provision was to impose a $500/MW per hour penalty (which quickly doubled to $1,000/MW) for every hour following an unexcused failure to commence Commercial Operation following the Maximum Time to Commercial Operation for the particular Facility.

This penalty was uncapped so that in six hours (in the case of a simple cycle gas turbine plant) this penalty would exceed the $5,000/MW in Liquidated Damages that were payable pursuant to Section 13.4 following an Event of Default.

If the Facility was offline as a result of an outage for which the GFO was deemed responsible, then a long-term outage could bankrupt a project. The Coalition considered for an example a 30 day unexcused outage of a 100 MW Credit Capacity Facility. After two hours the penalty rate is $1,000/MW. Thirty days at this rate netted a payment of $72,000,000. It seemed very late in the day for the TA to be proposing a provision, which offered such potentially catastrophic consequences for the GFO.

The Coalition stated it first discussed this provision with EAL during the February 8, 2001 meeting and did not agree with its imposition.

As such, the Coalition had a number of suggestions to propose in respect of it. They were as follows:

(a) the reference in subsection 3.2(a) to "best efforts" should be deleted and replaced with "reasonable commercial efforts". A "best efforts" obligation could be construed as requiring a party to spend money to achieve a particular goal until such time as the party was bankrupt. Obviously this was unacceptable from the perspective of any GFO;

(b) the $500/MW per hour quantum of the penalty prescribed in subsection 3.2(b) was clearly unreasonable, even before taking into consideration its doubling pursuant to subsection 3.2(c). The Coalition believed that a value of an order of magnitude of $100/MW per hour would be more reasonable. If the TA required the doubling prescribed in subsection 3.2(c), then the quantum of the number in subsection 3.2(b) should be $50/MW;

(c) there must be an aggregate cap on the amounts payable by any GFO pursuant to Section 3.2. The Coalition noted that for an Event of Default, the Liquidated Damage ceiling pursuant to Section 13.4 was $5,000/MW of Credit Capacity. That Liquidated Damage amount followed an Event of Default. A GFO's maximum liability pursuant to this Section 3.2 should not be allowed to exceed such Liquidated Damage amount for any individual failure pursuant to Section 3.2. The Board might also consider an aggregate cap for the total claims to be made by the TA pursuant to this Section 3.2;

(d) the last sentence of subsection 3.2(b) was particularly offensive in view of the quantum of the penalty proposed by the TA. A failure of 30 seconds in an hour on 100 MW of Credit Capacity ought not to result in an additional $100,000 of penalty. If the TA was fixated upon round numbers, the Coalition requested that in such instances the TA round down to the nearest complete hour of delay in Commercial Operation. Otherwise the Coalition would accept a proportional quantification of these penalties on the basis of five minute increments within any hour;

(e) as already noted, the doubling of the penalty amount prescribed in subsection 3.2(b) pursuant to subsection 3.2(c) was unacceptable to the Coalition without both: (i) a significant reduction in that initial quantum; and (ii) a cap on the aggregate liability of the GFO for such penalty;

(f) the payment obligations of the GFO were triggered on the entire amount of the Credit Capacity notwithstanding that the GFO may suffer only a shortfall of a few MW of its overall Credit Capacity obligation. The Coalition believes that the System was better off receiving a high percentage of the Credit Capacity requested by the TA at any particular time even if the entire Credit Capacity was unavailable. Therefore, the TA should be required to accept an amount of available capacity less than the Credit Capacity and any penalties otherwise payable pursuant to Section 3.2 should be based solely upon the shortfall in capacity, not upon the entire Credit Capacity. In other words, if a GFO suffered a de-rating of 5% on a Credit Capacity of 100 MW, the System was better off receiving the 95 MW that the GFO could provide and, if provided, the GFO should only pay the penalty prescribed in subsection 3.2(b) to the extent of the 5 MW shortfall not the entire Credit Capacity; and

Views of EAL

In its submission of February 16, 2001, EAL noted that the Coalition opposes EAL's proposed penalty of $500/MW per hour for missing the Maximum Time to Commercial Operation. The Coalition's proposal was made in response to the Coalition's concern that contract termination was too severe a penalty for such a failure.

In EAL's view, a GFO, acting prudently, will have no trouble meeting the already generous response times except in cases where the Facility is incapable of responding, which cases are already adequately covered by Forced Outage, Force Majeure, and Permitted Unavailability provisions.

As mentioned above, EAL considers that the Coalition offered to meet stringent dispatch requirements in exchange for valuable supplemental payments. EAL stated that it agreed to impose a financial penalty for failure to meet generous dispatch response times instead of considering this to be a breach of contract. The Coalition now seeks to further dilute this penalty to the point of insignificance in EAL's view.

In EAL's view, the GFOs are seeking to virtually eliminate performance risk (while continuing to receive supplemental payments) is obvious from their requests to:

- change "best efforts" to "reasonable commercial efforts" [§5(a)];
- reduce the penalty for failure to meet the Maximum Time to Commercial Operation to either $100/MW or $50/MW [§5(b)]. In EAL's view the penalty proposed by the Coalition is totally inadequate—they are a mere 10% and 5%, respectively, of the maximum amount the GFOs can receive from load customers for their output.
- round *down* to the nearest hour for timing purposes [§5(d)];
- pro-rate the penalties by the shortfall amount [§5(f)]. EAL notes that the delivery requirement has already been relaxed by granting that deliveries within 90% of contract capacity will be deemed to have met the dispatch request.
- replace the standard of Good Electric Operating Practice by one that simply requires that there be neither gross negligence nor wilful misconduct [§5(g)], even though the Board specifically approved Good Electric Operating Practice in Decision 2000-76.

EAL opposes all of these changes.

However, EAL proposed to simplify the performance penalty structure and to limit the GFOs' financial exposure, EAL proposes to leave the penalty at $500 per MW of Credit Capacity per hour for a maximum of 24 hours beyond the Maximum Time to Commercial Operation. Beyond the 24-hour period, the Transmission Administrator would have the option of terminating the contract.

Views of the Board

The Board agrees with the Coalition that the words "best effort" could be interpreted so as to impose an unfair burden upon the GFO.

The Board also has concerns about the potential magnitude of claims that a GFO might theoretically or potential face through the proposed conditions. If generation is to be considered a reliable replacement for transmission, the Board agrees that meaningful provisions must exist.

Therefore, the Board agrees with the simplification proposed by EAL on February 16, 2001 with some modifications from the Coalition. The Board does not, however, agree with the Coalition that a value of an order of magnitude of $100/MW per hour would be more reasonable.

Therefore, the Board directs EAL, in its second refiling, to make the following revisions to section 3.2:

- substitute the words "reasonable commercial efforts" for "best efforts"
- the payment obligations of the GFO should be triggered on the shortfall of the MW from the overall Credit Capacity obligation. The TA should be required to accept an amount of available capacity less than the Credit Capacity and any penalties otherwise payable pursuant to Section 3.2 should be based solely upon the shortfall in capacity, not upon the entire Credit Capacity.
- the penalty prescribed should be $500/MW per hour for a maximum of 24 hours beyond the Maximum Time to Commercial Operation for Section 3.2(b).
- section 3.2(c) should be deleted.
- for an event, the GFO's total financial exposure would be limited to the penalties payable for each hour for a maximum of 24 hours. Accordingly, the aggregate cap on the amounts payable by any GFO pursuant to section 3.2 for an event would be equal to the maximum shortfall from Accepted Credit Capacity in each hour multiplied by the $500/MW and summed over a 24-hour period. Beyond the 24-hour period, the Transmission Administrator would have the option of terminating the contract.
- except for adjustments required to give effect to the above, all other provisions of Section 3.2 remain.

In order to understand the performance of GFOs and the TA, the Board directs EAL in all future GTAs for the term of the LBC SO contracts to report on any occurrences where the GFO exceeded the maximum time to commercial operation requirement.

8 DEFINITION OF FORCED OUTAGE - GOOD ELECTRIC OPERATING PRACTICE

Views of the Coalition

The Coalition stated that imposition of Section 3.2 required the Coalition to reconsider carefully the definition of “Forced Outage” as set forth in Schedule 1. Based upon the Coalition’s review of that definition and its implications for this Section 3.2, the Coalition believed that the reference to Good Electric Operating Practice within such definition was not reasonable.

If an outage was not to be construed a “Forced Outage” if the GFO has breached any aspect of Good Electric Operating Practice, then the potential for a GFO to be second-guessed after a Forced Outage, and then being subject to liability pursuant to Section 3.2, was enormous.

On this basis, the Coalition believed that the appropriate standard for determining what constituted a Forced Outage was not the adherence to the relatively high standard of Good Electric Operating Practice. Rather the Coalition argued that the standard should be one where any outage should be a Forced Outage unless the GFO’s acts or omissions in respect of such outage constituted gross negligence or willful misconduct. Otherwise, a comparatively trivial operator error or misjudgment could, after the fact, be construed as not complying with Good Electric Operating Practice and as a result could expose a GFO to the brand new penalties proposed by the TA pursuant to Section 3.2.

The Coalition requested the deletion from the definition of “Forced Outage” of the following phrase:

> “which could not have been avoided through the use of Good Electric Operating Practice” and its replacement with the phrase: “other than those resulting directly from acts or omissions of the Generating Facility Owner which constitute gross negligence or willful misconduct”.

Views of the Board

The Board is not persuaded that the definition of forced outage needs to be changed. The Board considers that LBC generation facilities need to be maintained at a standard consistent with Good Electric Operating Practice. The Board considers that a relaxation of this standard could lead to the LBC generating facility being a less reliable substitution for transmission facilities.

The Board notes that it has addressed some of the concerns of the Coalition respecting Section 3.2 by reducing and capping the penalties for not meeting the Maximum Time to Commercial Operation.

9 FUNDAMENTAL APPROVALS – Section 7.1(a)(iv)

Views of the Coalition

The Coalition maintained, with respect to Section 7.1(a)(iv), that the reference to approvals needed to be broader than merely the EPA Approval and the HEEA Approval. The inclusion of the reference "(or equivalent approvals)" was inadequate to address the Coalition's concerns. The Coalition reiterated their request to have the definition of "Approvals" amended in Schedule 1 to read as follows:

> **"Approvals"** means, collectively, the AEUB Order, the HEEA Approval, the EPA Approval and all other orders, permits, approvals and consents required by Legislation in order to own, construct and operate the Facility as are identified in the Construction Schedule.

Views of ENMAX

ENMAX submitted that the reference to approvals should be broadened to include all required approvals.

Views of EAL

EAL in its submission of February 16, 2001 states that the Coalition repeats its comment of January 31 that the definition of Approvals should be expanded. EAL notes that the requested expansion include, "…and all other orders, permits, approvals and consents required by Legislation in order to own, construct and operate the Facility as are identified in the Construction Schedule."

EAL stated that the definition of Approvals is meant to deal with fundamental approvals. Expanding the definition would give rise to the real possibility that a GFO would have an option to exit the Agreement as a result of not receiving a non-material approval. EAL considered that this was the definition of Approvals accepted by the Board in relation to the IBOC Agreements. Accordingly, EAL submitted that there is no reason to deviate from it.

Views of the Board

The Board agrees with EAL that this matter has been adequately addressed, including the most recent amendment by EAL that provides for "(or equivalent approvals)". The Board agrees that the intent is to provide for fundamental provisions and that the achievement of the generation by the required date is important. Excessive broadening of this provision could have unintended or undesirable results for system security.

10 AUDIT PROVISIONS – Sections 3.1, 12.3 and 17.2

Views of the Coalition

With respect to sections 12.3 and 17.2 the Coalition noted that there was a lack of symmetry. Section 12.3 only allowed the GFO one year to dispute payments from the TA while section 17.2 allowed the TA 6 years to audit the GFO regarding the records of the facility.

The Coalition proposed that the audit periods for both parties should be either:

(i) two years; or

(ii) two years following the end of the calendar year to which the particular payment or information, as the case may be, related.

The Coalition's position was based upon both typical industry practice and a belief that there was no reason for one party to have an audit period six times longer than it was prepared to grant to the other.

Views of EAL

EAL in its submission noted that the Coalition proposed a modification of the audit periods [§7]. EAL submitted that this issue was dealt with in Decision 2000-76, and the Coalition failed to note any concern in its January 31, 2001 submission. EAL requested that the Board should not consider the Coalition's proposal.

Views of the Board

The Board understands the Coalition's concerns in this regarding the lack of symmetry in Section 12.3.

However, the Board agrees with EAL that the provision as refiled is appropriate and accordingly the Board approves EAL's approach. The Board rejects the Coalition requests.

The lack of symmetry is intentional to close off complications in a reasonable manner resulting from revisions associated with the supplemental payments.

However, the Board considers there are related audit issues that should be addressed as a result of the Coalition raising issues on operations and maintenance matters. This has resulted in the Board examining a number of provisions where changes need to be made.

Accordingly, the Board directs EAL in its second refiling to revise the following sections:

- Revise Section 17.2(a) as follows (changes bolded and italicized)
    - The Transmission Administrator shall have the right, exercisable upon reasonable prior notice to the Generating Facility Owner to audit or examine the books, records ***(including, but not limited to, operations records, maintenance records, and maintenance plans),*** Metering Equipment and metering status indication devices of the Generating Facility Owner as they relate to the Facility at the Transmission Administrator's sole cost and expense, to verify the accuracy of any information, data, notice, claim, demand, charge, payment, cost, expense or computation reported, gathered, collected, made or incurred by the Generating Facility Owner, or the performance of the covenants and obligations by the Generating Facility Owner under and pursuant to the Agreement. ***It is understood that reasonable prior notice will be reduced in the event that an audit is part of the Transmission Administrator's assessment of a Recovery Plan.***
- Revise Section 3.1(a) as follows (changes underlined and italicized)

   - The Generating Facility Owner shall construct the Facility and shall ensure that the Facility is designed, constructed, ***operated, and maintained*** in accordance with Good Electric Operating Practice and shall, as it relates to the Facility, comply with all applicable Legislation, including, without limitation, the stipulations, terms and conditions of any regulatory approvals, decisions, orders, licenses or other determinations.
- Modify the above noted wording changes as necessary to give practical effect to the Board's intentions.

11 DEFINITION OF DISPATCH - Section 4.1(b)

Views of the Coalition

With respect to section 4.1(b) the Coalition requested that the term "Dispatched" in section 4.1 (b) be qualified to restrict it to times when the Facility "is required to be Dispatched due to binding transmission constraints". Again, the Dispatch should be based on the Transmission Administrator's operational guidelines (for the reasons stated in section 1.2 above).

Views of EAL

EAL understood that the Coalition has agreed with EAL that this change is not required based on the requirement for Board approval of the operating guidelines that will be used to determine when to issue a Dispatch Instruction.

Views of the Board

The Board notes that the Coalition asked that the term "Dispatched" in Section 4.1(b) of the contract be qualified to restrict it to times when the Facility "is required to be Dispatched due to binding transmission constraints." The Board notes that EAL understood that the Coalition has agreed with EAL that this change is not required. A change is not required based on the requirement for Board approval of the operating guidelines that will be used to determine when to issue a Dispatch Instruction.

The Board agrees that these requirements need not be finalized at this time.

However, the Board does not agree with the Coalition that the Facility should only be dispatched when required "due to binding transmission constraints". The Facility is to be available as a substitute for transmission facilities. Transmission facilities are available with very little down time. The Board does not accept that the Coalition's competitive financial interests should interfere with the availability of this service.

12 TOTAL REQUESTED HOURS

EAL proposed the following wording for Article 5.1(b) of the LBC Entitlement Offer:

(b) The Annual Minimum Payment applicable to such Operating Year (if any) shall be the maximum of:

(i) Zero (0); or

(ii) (Annual Minimum Hours minus Total Requested Hours) X Credit Capacity in Commercial Operation X LBC Rate.

Where, subject to *Section 5.1(b)*:

"Total Requested Hours" means the total number of hours in an Operating Year during which the Facility is Dispatched by the System Controller. Total Requested Hours will also include all such hours when the Facility was unable to respond to Dispatch as a result of a Forced Outage or Force Majeure; however, it will not include such hours when the Facility was unable to respond to a Dispatch as a result of a Permitted Unavailability.

Views of TCE

With respect to section 5.1(b)(ii), TCE submitted that if a Facility was unable to respond to Dispatch as a result of Force Majeure, those hours should not be deducted from the Annual Minimum Hours. TCE noted that the Generating Facility Owner ("GFO"); according to the definition of "Target Hours" in section 4.1(b)(iv)(D), did not appear to be receiving any LBC Payments during Force Majeure. TCE maintained that to leave the provision as it was could result in a reduction of the Annual Minimum Hours paid to a GFO during Force Majeure, which may be out of the control of the GFO. As such, TCE suggested that the words "or Force Majeure" in the second sentence of the definition of "Total Requested Hours" be moved to the end of the entire second sentence (following the words "Permitted Unavailability").

Views of EAL

EAL noted that TCE suggested Total Requested Hours should exclude hours when the Facility is Dispatched during an event of Force Majeure. EAL stated the definition of Total Requested Hours must include hours when the Facility is Dispatched during an event of Force Majeure in order to prevent payments from the Transmission Administrator to the GFO during such events. It was normal business practice that a service provider did not receive payments for services that it could not provide. EAL stated that the GFO would not receive the Monthly LBC Payment during an event of Force Majeure, neither should it receive the Annual Minimum Payment during such an event.

Views of the Board

The Board concurs with EAL that the definition of Total Requested Hours must include hours when the Facility is Dispatched during an event of Force Majeure in order to prevent payments from the TA to the GFO during such events.

Accordingly, the Board accepts EAL's explanation and no change is necessary to EAL's definition of total requested hours in the LBC Standing Offer.

13 ACCEPTANCES IN MULTIPLE ZONES

Views of TCE

TCE understood that the SO that would be commenced February 20, 2001 would relate to several zones and that credits for each of these zones would be posted concurrently. However, if there were multiple bids accepted in multiple zones, TCE stated that it was not clear, how these contracts could be binding, if there was a bid down process. Furthermore, TCE stated that it was not clear what EAL would do in this situation. For instance, will EAL conduct bid downs in both zones concurrently? If bid downs in two zones are accepted concurrently, will EAL still have some discretion to determine which contract is "binding"?

TCE stated that the concern here is that EAL has maintained the ability to determine how to proceed with the SO for various zones once one zone has an accepted binding bid, yet it was not clear what happened when two bids in two zones were accepted. Likewise, it was not clear what EAL would do if two zones concurrently received acceptances.

TCE was concerned that if the single acceptances in two separate zones resulted in a binding contract, then presumably EAL had no discretion to determine if one acceptance would be binding and another not. TCE requested the Board direct EAL to incorporate such clarifications in their Memorandum.

Views of EAL

In response, EAL explained it would structure the Standing Offer such that the start times in each zone were staggered, that is, such that no 15-minute period in one zone will overlap with a 15-minute period in another zone.

Views of the Board

The Board notes that TCE requested clarification as to how the Transmission Administrator would determine if an Acceptance of a Standing Offer were binding. This situation could arise when several Acceptances occurred in separate zones during the first 15 minutes of a Standing Offer (or the first 15 minutes following an increase to the offered LBC Rate).

The Board accepts that EAL's proposed approach is suitable, except for Zone 1 and 2. The Board considers that commencing either Zone 1 or Zone 2 ahead of the other would be unfair to generators wishing to accept offers in the other zone. From a practical perspective, Zone 1 and 2 need to be treated as one zone since only 100 MW will be accepted from a combination of both zones not from each zone.

Accordingly, the Board directs EAL to operate the acceptance process in Zone 1 and Zone 2 simultaneously and to include both zones in any bid down procedure so all participating generators have an equal opportunity to be the winning accepted offer.

14 LIQUIDATED DAMAGES – EVENT OF DEFAULT

The issue of default was addressed in Decision 2000-76 as follows:

> The Board considers EAL's $5000/MW of capacity to be unacceptable and not meaningful. The Board notes that the $5000/MW would only cover costs, at an interruptible load price of $100/MWh, for approximately two days. In the event of default the TA may require a significant period to remedy.[1]

Further in Decision 2000-76, the Board directed EAL to address the issue of contract provisions that provide for liquidated damages in the event of default.

Views of the Coalition

The Coalition did not address the magnitude of the liquidated damage provision. However, in related matters the Coalition did express its concern about Section 3.2. The Coalition stated if the Facility was offline as a result of an outage for which the GFO was deemed responsible, then a long-term outage could bankrupt a project. The Coalition calculated that a one-month outage of a 100 MW Credit Capacity Facility could result in a payment of $72,000,000. The Coalition suggested a number of changes including a reduction from $1000 per MW.h to $100 per MW.h. This would result in a charge of $7.2 million in the Coalition's example.

Views of EAL

EAL in its response to Board's directions, provided the following response:

> …Also as in the IBOC contracts, if the COD does not occur within six months following the RCOD, this will be an Event of Default, allowing the TA to terminate the agreement and collect Liquidated Damages, as set out in Section 13.4(c). EAL proposes an improvement to the payment for Liquidated Damages: the $5000/MW amount should be adjusted over the Term of the contract at the rate of the Consumer Price Index. This would ensure the size of the payment doesn't lose its significance over time.

In its submission of February 16, 2001, EAL stated that Section 13.4 is the same "Termination for Event of Default" provisions accepted by the Board in relation to the IBOC Agreements, and there is no reason to alter it.

[1] Decision 2000-76, page 81

Views of the Board

It is not unexpected that the Coalition did not address the magnitude of the liquidated damage provision in view of the magnitude proposed by EAL and the concerns of the Board.

In general, the Board considers that EAL has addressed the Board's concerns on page 81 of 2000-76 and that parties have provided meaningful input. In other parts of this Decision, the Board will provide its decisions on matters other than liquidated damages.

However, the Board considers that EAL has not met the Board's expectation, in a meaningful way, with regard to liquidated damage in the events of default. Since EAL did not address it in a meaningful manner, it is not surprising that other parties did not comment on EAL's refiling.

Consequently, the Board will direct a revised amount for liquidated damages. In doing so, the Board will consider how related issues were addressed in EAL's refiling and the views of parties on those issues.

The Board will examine the following related issues:

- Penalties for exceeding the Maximum Time to Commercial Operation - Article 3.2
- Eligibility Payments – Article 4.1(e)
- Termination for Event of Default – Article 13.4 (c) and (d)
- Termination by Generating Facility Owner - Article 13.6

Using an example of a 100 MW facility, the Board will now assess the magnitude of those financial provisions in the context of EAL's refiling.

Table 1:Assessment of EAL's Refiling
(Financial Provisions, & Liquidated Damages)

Article	Provision	Financial Outcome ($)
3.2 (b) Max Time to Commercial	$500 per MW.h x Credit Capacity in Commercial Operation for each hour	- $50,000 per hour - $1,200,000 per day - $36,000,000 per month
3.2 (c) Max Time to Commercial	$1000 per MW per hour if time exceeds twice the applicable Maximum Time	- $100,000 per hour - $2,400,000 per day - $72,000,000 per month[2]
4.1 (c) Incentive Payment	- Minimum Annual Hours of 7906/yr. times using $5/MW	- $3,950,000 per year
4.1(e) Eligibility Payment	- COD not achieved by RCOD. - $50 x Credit Capacity/day - No more than 6 months	- $912,000 after 6 months
4.1 (f) Incentive LBC Rate	- COD 6 months earlier than RCOD est. at twice rate of $5/MW @ 90%	- $4,400,000 in 6 months
13.4 (c) Termination for Event of Default	- $5000 times MW of Credit Capacity	- $500,000
13.6 Termination by Generating Facility Owner	- 13.4 (c) plus 13.4 (d) - $5000 x MW/Credit Capacity plus $50/MW of Capacity/day to 182 days	- $1,410,000 ($500,000 plus $910,000)

The Board in determining the Board Approved provisions for 13.4(c) and 13.6 has considered the appropriateness of liquidated damages in light of a reasonable estimate of LBC payments using a notional $5 per MWh

Although very mindful of the negative impact on consumers of default, the Board has not used this impact as the basis for this Decision on liquidated damages. The Board considers that a liquidated damage to cover the actual impact on consumers would have the effect of significantly increasing the cost of the LBC SO credit payments and could limit the participation of otherwise interested generators in the LBC SO procurement process. Further, the Board did not consider it fair and reasonable to generators to establish the liquidated damages in that manner when the LBC SO is an incentive program to encourage the location of generators in a system desired area vs. the generator's other alternatives.

In developing its approved amount of liquidated damages in the event of default for Section 13.4 (c), the Board used the following rationale

- The amount of the liquidated damages in the event of default should be based on the estimated minimum time for a replacement project of 18 months (1.5 years).

[2] The Coalition considered for example a 30 day unexcused outage of a 100 MW Credit Capacity Facility. After two hours the penalty rate is $1,000/MW. Thirty days at this rate netted a payment of $72,000,000.

- Since an event of default could occur at any time during the life of the project, the Board used the Annual Minimum Hours at year 10 (mid life of the contract) of 7074 hours per year.
- The value of the liquidated damages was established at a notional value of $5/MW.h of Incentive Payments.
- The calculations results in an amount of $53,055 per MW of Accepted Credit Capacity (7074 hours times $5/MW.h times 1.5 years)
- The value is reasonable by comparison to the LBC payment from annual incentive payment revenue and the opportunity to earn the incentive LBC rate for COD before RCOD.
- The calculation was rounded down to $50,000 per MW.

Table 2: Board Approved Provisions

Article	Provision -	Financial Outcome - ($)
Board Approved 13.4 (c) Termination for Event of Default	- **$50,000 times MW of Credit Capacity**	- **$5,000,000**
Board Approved 13.6 Termination by Generating Facility Owner	- **13.4 (c) plus 13.4 (d)** - **$50,000 x MW of Credit Capacity plus $120/MW of Capacity/day to 182 days**	- **$7,184,000** **($5,000,000 plus $2,184,000)**

Accordingly, the Board directs EAL in its second refiling to revise Article 13.4 (c) and (d) as follows:

(c) declare the amount equal to $50,000 (fifty thousand dollars) multiplied by the Accepted Credit Capacity immediately due and payable on account of Liquidated Damages. The Liquidated Damages formula set out in this *Section 13.4(c)* will, commencing in the first Operating Year, be adjusted every February 1st by the percentage change over 12 Months in the *January All-items Consumer Price Index* for Alberta;

(d) in the event of a termination under *Section 13.6*, declare the amount equal to $5 (five dollars) multiplied by the Tranche of Credit Capacity per day multiplied by 24 (twenty – four) hours per day multiplied by one hundred eighty two (182) days minus any Eligibility Payments the Generating Facility Owner has already paid to the Transmission Administrator in respect of the said Tranche of Credit Capacity, immediately due and payable on account of Liquidated Damages. For greater clarity in the event of a termination under *Section 13.4* the Liquidated Damages under *Sections 13.4(c)* and *13.4(d)* shall both apply; and

15 LIABILITY – Section 13.7

Views of Duke Energy

Duke expressed concern about Article 13.7 Limitation of Liability, section (a) Direct Loss or Damage which read:

> For the purposes of this Article, "Direct Loss or Damage" means, in relation to a Party, any and all liabilities, indebtedness, obligations, losses, damages, claims, assessments, fines, penalties, costs, fees and expenses of any kind, nature or description suffered or incurred by such Party, arising out of or in any way connected with a breach or default of this Agreement by the other Party…

Duke was concerned that this language, rather than adequately defining direct costs, included other costs that were indirect in nature. Duke took some comfort in EAL having liability protection through legislation but noted that the liability protection was subject to periodic review. Duke requested that should the existing liability protection afforded EAL as Transmission Administrator be nullified, Article 13.7 still be considered contractually as if the liability protection were in effect for the term of the LBC SO contract.

Views of the Board

The Board notes that Duke did not quote the entire Section 13.7 in its letter. The complete section is shown below"

> 13.7 Limitation of Liability
> A Party shall have no liability to the other Party for any matter or thing arising out of or in any way connected to this Agreement, except in respect of:
> (a) Direct Loss or Damage;
> (b) Liquidated Damages, as calculated under *Article 13*; and
> (c) any obligations for the payment of Monthly LBC Payments, Monthly Incentive LBC Payments, Annual Minimum Payments and Monthly Supplemental Payments.
>
> For the purposes of this Article, "**Direct Loss or Damage**" means, in relation to a Party, any and all liabilities, indebtedness, obligations, losses, damages, claims, assessments, fines, penalties, costs, fees and expenses of every kind, nature or description suffered or incurred by such Party, arising out of or in any way connected with a breach or default of this Agreement by the other Party, including interest which may be imposed therewith, court costs, costs resulting from any judgments, orders, awards, decrees or equitable relief and costs of legal counsel, on a solicitor and own client basis (collectively and individually a "**Claim**") but, shall, in no event, include Claims for loss of profit, loss of revenue, loss of production, loss of earnings, loss of contract or any other indirect, special or consequential loss or damage whatsoever.

The Board may not understand the implication of Duke's concern as the issue was communicated very concisely and with little elaboration.

The Board notes that while EAL is currently afforded some degree of liability protection, through legislation, there is no guarantee that this protection for EAL will be in effect for the entire term of the LBC SO contract. If Duke's concern is that a GFO may inadvertently be liable for consequential damages, the Board wishes to make clear that a GFO should not have any consequential damage liability. This position should endure regardless of the status of any legislated liability that the TA enjoys or may not enjoy at any point in the future. The Board considers that the fully quoted Section 13.7 makes this position clear.

However, the Board considers that Duke's concerns are best addressed by the TA and any necessary revisions dealt with by the TA.

Therefore, the Board directs EAL in its second refiling to address the concern of Duke Energy and make appropriate wording changes in Article 13.7 if warranted. Further the Board directs EAL in its second refiling to provide its views on Duke's concerns and the reasons for any action or inaction on Duke's concerns.

Further, the Board directs EAL in its second refiling to update Section 13.7 to include the penalties arising from Section 3.2 and to verify to the Board that Section 13.7 accurately includes all provisions.

16 TRANSMISSION DEVELOPMENT PLAN

Views of Coalition

The Coalition noted EAL stated that it would take "up to two years to achieve" the appropriate planning criteria. The Coalition was concerned that the planning criteria relied upon by EAL in the proceeding, and accepted by the Board in an "abundance of caution" should not be entrenched by the passage of time. The Board's expectation that EAL fully address the planning criteria for its ten-year transmission development plan does not appear to be unreasonable, particularly given the discussion this topic received during the proceeding leading to Decision 2000-76.

The Coalition requested that EAL provide a concrete schedule allowing this important issue to be determined in the approval process for the 2002 transmission development plan.

The Coalition proposed that the TA seek to address the Planning Criteria in one year. Further, in order to satisfy Direction 6 (Development Plan), it seemed that the "appropriate reliability criteria" must be established. The recommended reliability criteria should be at least finalized for the 2002 transmission development plan.

A critical component of Decision 2000-76 was that EAL submit an annual transmission development plan to the Board "for approval". This development plan was "at a minimum" to include the enumerated items (including "appropriate reliability criteria").

EAL's response to this Direction contains no commitment to actually submit this annual transmission development plan to the Board for approval. The Coalition requests that EAL make this commitment and describe when the annual transmission development plan, as described by the Board, would be submitted and how the approval process would, in EAL's view, proceed. The Coalition would also reiterate its understanding that the development plan should not be a substitute for specific facilities applications.

Views of EAL

EAL noted that the Coalition discussed planning criteria and the transmission development plan in section 1.1. EAL proposed to develop separate, comprehensive planning criteria with respect to the bulk, non-bulk, and POD components of the transmission system. Planning criteria for the non-bulk and POD components had not been formally developed before now. EAL stated a first draft of these criteria was contained in the *Transmission Development Plan 2001-2010*, published for comment[3] and public consultation in December 2000. (For clarification, EAL interpreted the Coalition's reference to the "2002 transmission development plan" to mean the plan that would be published in December 2002, covering the years 2003 through 2012.)

EAL hoped to reach a high degree of consensus before submitting the new planning criteria to the Board for approval. However, given the diverse interests of industry stakeholders, EAL believed that a significant amount of time may be required to do so.

EAL is prepared to commit to a process whereby it would submit planning criteria for approval by the end of 2001. EAL noted that the Transmission Planning Committee (TPC), chaired by EAL, was one mechanism through which industry stakeholders could provide their input to the planning process. EAL proposed that the TPC would be used to develop new planning criteria. TPC meetings are held quarterly, with the first meeting set for February 14, 2001.

EAL stated that it would file its transmission development plans for approval at the end of each year. EAL suggested the associated regulatory proceedings be written ones that focus on the policy components rather than on individual facility additions. This approach was proposed because the development plan was a "living" document, subject to constant change. Approving the plan in its entirety would not allow facility proposals to respond to changing requirement from supply and demand customers. EAL concurred with the Coalition's view that each specific facility should continue to be subject to a separate facilities application.

Views of the Board

The Board agrees with EAL's proposal to file its annual transmission development plan for approval at the end of each year. However, the Board considers that an oral proceeding should be held, at least with respect to the initial transmission development plan to be filed for approval in December 2001. It may be that subsequent transmission development plans could be dealt with by way of written proceedings after the transmission development plan process, planning criteria and other requirements have been more fully developed and approved by the Board.

The Board considers that the transmission development plan should be a high level plan that establishes an overview of the transmission facilities required over the next ten years. However, the Board considers that the transmission development plan should also provide details of

[3] The Development Plan requested written comments by the end of March 2001

expected transmission capital additions and retirements for the immediate future test year with respect to the bulk, non-bulk, and POD components of the transmission system. These details will form the basis for the TA's forecast revenue requirement for the immediate future test year.

The Board agrees with EAL that the transmission development plan by necessity is a "living" document, subject to the changing requirements of supply and demand customers. However, the Board does not agree that approving the transmission plan in its entirety precludes the ability of the TA to respond to the changing requirements.

The Board notes that the main area of change would be at the POD level of the transmission plan for the immediate future test year. The Board considers that provisions for periodic updates, filed for information, to the approved plan could handle any changes at the POD level and, if necessary, at the non-bulk and bulk level as well.

The Board concurs with EAL and the Coalition that each specific facility should continue to be subject to a separate facilities application.

The Board agrees with EAL's objective of attempting to reach a high degree of consensus before submitting new transmission planning criteria to the Board for approval. The Board also agrees with EAL that a process should be developed which would culminate in the submission, by the end of 2001, of new transmission planning criteria for approval by the Board in conjunction with the transmission development plan to be filed in December 2001.

Accordingly, the Board directs EAL by March 31, 2001, to establish the timetable for the process to submit new transmission planning criteria to the Board for approval by the end of 2001.

17 SECOND REFILING

The Board directs EAL to refile with the Board at its earliest convenience the following:

- Location Based Credit Entitlement Offer (for approval)
- Explanatory Memorandum for Persons Seeking Pre-Qualification for Participation in Standing Offers for Location Based Credits (for information)
- Response to EUB Directions (for information)

The above materials do not need to be all submitted at the same time if this would delay approval of the Location Based Credit Entitlement Offer.

The Board will then issue its final approval of the Location Based Credit Entitlement Offer.

The Board also requests that EAL to distribute a copy of material such as the notice and process information to all Parties, including the Board, when it distributes this information to potential GFOs.

18 SUMMARY OF DIRECTIONS

This section is provided for the convenience of readers. In the event of any difference between the Directions in this section and those in the main body of the report, the wording in the main body of the Decision shall prevail.

1. The Board directs EAL, in its second refiling, to revise Clause 4.1(e) to increase the proposed eligibility payment or penalty from $50 per day per MW of credit capacity to $120 per day per MW for a period of up to 6 months. (Page 6)

2. The Board directs EAL, in a second refiling, to incorporate its intent as stated in its February 16, 2001 clarification by starting to count the number of Cure Periods six months after the COD. The clarification should clearly identify the impact on both the number of Cure Periods and against the aggregate Cure Period limit of 365 days. The Board assumes that EAL intended the six month period not to count against the aggregate Cure Period limit of 365 days as well. (Page 9)

3. Accordingly, the Board directs EAL, in a second refiling, to make the necessary changes to implement the above views of the Board on Section 3.1(c) on the following issues:

    - insurance for operations,
    - the securing of maintenance services, and
    - the discretionary authority for adjusting deadlines for provision of any necessary document. (Page 11)

4. Accordingly, the Board directs EAL to announce a cut-off date for accepting applications for lower-voltage connections associated with the LBC SO process. (Page 12)

5. Therefore, the Board directs EAL in its second refiling to reword the compatibility obligation in respect of the MVAS be altered in subsection 3.1(g)(i) as follows:

    > …be compatible with the Transmission Administrator's MVAS as it exists at the date hereof, and shall further use all reasonable commercial efforts to implement any changes in the Transmission Administrator's MVAS as approved from time to time, provided that the costs associated with such changes shall be borne by the Generating Facility; (Page 14)

6. Therefore, the Board directs EAL, in its second refiling, to make the following revisions to section 3.2:

    - substitute the words "reasonable commercial efforts" for "best efforts"
    - the payment obligations of the GFO should be triggered on the shortfall of the MW from the overall Credit Capacity obligation. The TA should be required to accept an amount of available capacity less than the Credit Capacity and any penalties

otherwise payable pursuant to Section 3.2 should be based solely upon the shortfall in capacity, not upon the entire Credit Capacity.

- the penalty prescribed should be $500/MW per hour for a maximum of 24 hours beyond the Maximum Time to Commercial Operation for Section 3.2(b).

- section 3.2(c) should be deleted.

- for an event, the GFO's total financial exposure would be limited to the penalties payable for each hour for a maximum of 24 hours. Accordingly, the aggregate cap on the amounts payable by any GFO pursuant to section 3.2 for an event would be equal to the maximum shortfall from Accepted Credit Capacity in each hour multiplied by the $500/MW and summed over a 24-hour period. Beyond the 24-hour period, the Transmission Administrator would have the option of terminating the contract.

- except for adjustments required to give effect to the above, all other provisions of Section 3.2 remain. (Page 17)

7. In order to understand the performance of GFOs and the TA, the Board directs EAL in all future GTAs for the term of the LBC SO contracts to report on any occurrences where the GFO exceeded the maximum time to commercial operation requirement. (Page 17)

8. Accordingly, the Board directs EAL in its second refiling to revise the following sections:

   - Revise Section 17.2(a) as follows (changes bolded and italicized)

     - The Transmission Administrator shall have the right, exercisable upon reasonable prior notice to the Generating Facility Owner to audit or examine the books, records ***(including, but not limited to, operations records, maintenance records, and maintenance plans),*** Metering Equipment and metering status indication devices of the Generating Facility Owner as they relate to the Facility at the Transmission Administrator's sole cost and expense, to verify the accuracy of any information, data, notice, claim, demand, charge, payment, cost, expense or computation reported, gathered, collected, made or incurred by the Generating Facility Owner, or the performance of the covenants and obligations by the Generating Facility Owner under and pursuant to the Agreement. ***It is understood that reasonable prior notice will be reduced in the event that an audit is part of the Transmission Administrator's assessment of a Recovery Plan.***

   - Revise Section 3.1(a) as follows (changes underlined and italicized)

     - The Generating Facility Owner shall construct the Facility and shall ensure that the Facility is designed, constructed, ***operated, and maintained*** in accordance with Good Electric Operating Practice and shall, as it relates to the Facility, comply with all applicable Legislation, including, without limitation, the stipulations, terms and conditions of any regulatory approvals, decisions, orders, licenses or other determinations.

- Modify the above noted wording changes as necessary to give practical effect to the Board's intentions. (Pages 20-21)

9. Accordingly, the Board directs EAL to operate the acceptance process in Zone 1 and Zone 2 simultaneously and to include both zones in any bid down procedure so all participating generators have an equal opportunity to be the winning accepted offer. (Page 24)

10. Accordingly, the Board directs EAL in its second refiling to revise Article 13.4 (c) and (d) as follows:

    (c) declare the amount equal to $50,000 (fifty thousand dollars) multiplied by the Accepted Credit Capacity immediately due and payable on account of Liquidated Damages. The Liquidated Damages formula set out in this *Section 13.4(c)* will, commencing in the first Operating Year, be adjusted every February 1st by the percentage change over 12 Months in the *January All-items Consumer Price Index* for Alberta;

    (d) in the event of a termination under *Section 13.6*, declare the amount equal to $5 (five dollars) multiplied by the Tranche of Credit Capacity per day multiplied by 24 (twenty –four) hours per day multiplied by one hundred eighty two (182) days minus any Eligibility Payments the Generating Facility Owner has already paid to the Transmission Administrator in respect of the said Tranche of Credit Capacity, immediately due and payable on account of Liquidated Damages. For greater clarity in the event of a termination under *Section 13.4* the Liquidated Damages under *Sections 13.4(c)* and *13.4(d)* shall both apply; and (Page 27)

11. The Board notes that while EAL is currently afforded some degree of liability protection, through legislation, there is no guarantee that this protection for EAL will be in effect for the entire term of the LBC SO contract. If Duke's concern is that a GFO may inadvertently be liable for consequential damages, the Board wishes to make clear that a GFO should not have any consequential damage liability. This position should endure regardless of the status of any legislated liability that the TA enjoys or may not enjoy at any point in the future. The Board considers that the fully quoted Section 13.7 makes this position clear.

    However, the Board considers that Duke's concerns are best addressed by the TA and any necessary revisions dealt with by the TA.

    Therefore, the Board directs EAL in its second refiling to address the concern of Duke Energy and make appropriate wording changes in Article 13.7 if warranted. (Page 29)

12. Further the Board directs EAL in its second refiling to provide its views on Duke's concerns and the reasons for any action or inaction on Duke's concerns. (Page 29)

13. Further, the Board directs EAL in its second refiling to update Section 13.7 to include the penalties arising from Section 3.2 and to verify to the Board that Section 13.7 accurately includes all provisions. (Page 29)

14. Accordingly, the Board directs EAL by March 31, 2001, to establish the timetable for the process to submit new transmission planning criteria to the Board for approval by the end of 2001. (Page 31)

15. The Board directs EAL to refile with the Board at its earliest convenience the following:

    - Location Based Credit Entitlement Offer (for approval)
    - Explanatory Memorandum for Persons Seeking Pre-Qualification for Participation in Standing Offers for Location Based Credits (for information)
    - Response to EUB Directions (for information)

    The above materials do not need to be all submitted at the same time if this would delay approval of the Location Based Credit Entitlement Offer.

    The Board will then issue its final approval of the Location Based Credit Entitlement Offer.

    The Board also requests that EAL to distribute a copy of material such as the notice and process information to all Parties, including the Board, when it distributes this information to potential GFOs. (Page 31)

Dated in Calgary, Alberta on February 19, 2001.

ALBERTA ENERGY AND UTILITIES BOARD

(Original signed "N. W. MacDonald")

N. W. MacDonald, P. Eng.
Presiding Member

(Original signed "A. J. Berg")

A. J. Berg, P. Eng.
Member

(Original signed "R. G. Lock")

R. G. Lock, P. Eng.
Member

APPENDIX 1

1. VIEWS OF THE PARTIES

1.1 Issues Arising from Directions and Explanatory Memorandum

1.1.1 Views of FIRM

FIRM commented upon the following issues.

Incentive Payments and Eligibility Payments

FIRM noted that EAL addressed these payment issues in response to Board Direction #16 in Decision 2000 - 76.

It was FIRM's understanding (Explanatory Memorandum, page 4) that EAL was proposing an incentive payment of 2 times the LBC SO Rate for each hour that the generator is in operation ahead of the Required Commercial Operation Date (RCOD) for a period of up to 6 months. Conversely if the generator is late in achieving commercial operation an eligibility payment or penalty of $50 per day per MW of credit capacity is applicable for a period of up to 6 months. EAL indicated this approach was similar to IBOC payments.

FIRM noted there was not symmetry around the RCOD for proposed payments/receipts. For an assumed LBC SO Rate of $5/MWh FIRM calculated the incentive for early completion would be $10/MWh whereas the eligibility or penalty rate for missing the contract date would be a much lessor amount of $2.08/MWh ($50/24 hrs). For equivalency the eligibility payment would have to be in the order of $120 per day per MW for the assumed LBC SO Rate. Furthermore, as the LBC SO Rate increased the disparity between incentive and penalty payments would also increase.

FIRM recommended there be closer symmetry between the incentive and penalty provisions by increasing the daily eligibility payment (i.e. by assuming an LBC Rate or using the average of the existing IBOC Rates for calculation purposes) or using the same 2 times the LBC SO Rate formula.

Supplemental Payments

It was FIRM's understanding that the Generation Facility Owner (GFO) would be entitled to additional payments from the TA (Supplemental Payments) when the Facility was dispatched and the pool price was below an operating cost benchmark (Explanatory Memorandum, page 5). Further the benchmark is a formula calculated using a proxy for heat rate, spot natural gas prices, a proxy for maintenance costs, and actual variable transmission tariff charges and credits (including location specific loss factor charges or credits). EAL has modified the benchmark formula in this refiling to also include such variable transmission tariff charges.

However, FIRM maintained including variable transmission charges in the benchmark rate would increase the magnitude of potential supplemental payments to the generator. Supplemental payments are an offset to the difference between a generator's higher operating costs and the lower pool price. FIRM noted when a generator was in a transmission must run condition and entitled to supplemental payments the generator would also be eligible for the LBC SO credit.

Therefore FIRM submitted the LBC SO Rate should also be considered in determining the benchmark rate. That is, the benchmark rate should be:

(heat rate * fuel price index) + O&M + STS rate + LBC SO rate.

FIRM submitted that a generator would consider all variable charges/credits in determining whether to generate or not to generate. Since the LBC SO Rate is a variable credit, it should also be included in the operating cost benchmark determination.

Furthermore if there was a concern that inclusion of the LBC SO credit in the benchmark rate would tend to increase the generator's standing offer acceptance level then a business case should be prepared and presented to substantiate this concern.

Minimum Annual Hours

FIRM noted that EAL response to Board directive #12 addressed this issue.

FIRM stated the GFO was guaranteed to receive LBC SO payments for a set number of minimum annual hours as designated by the TA for each year of the 20 year contract (Explanatory Memorandum, page 5). These minimum annual hours were specified in Schedule 5 to the Location Based Credit Entitlement Offer.

FIRM noted that for the first 8 years of the contract the minimum annual hours represented a healthy 90% capacity factor with this capacity factor reducing on a sliding scale for the remaining 12 years of the contract. FIRM viewed this as a very substantial take-or-pay obligation for the initial years of the contract. FIRM submitted that the TA should provide details of the business case that justified this very high take-or-pay level in the initial years.

Gross vs. Net Metering

FIRM noted that EAL addressed this issue in response to Board Direction #20 and #21.

It was FIRM's understanding that the Standing Offer provided for a one-time GFO election of metering on a gross or net basis (Explanatory Memorandum, page 6) for purposes of calculating the LBC SO payment. With the election of the gross metering basis, the generator would also be responsible for STS charges based on gross metering.

However, with gross metering FIRM had a potential concern with DTS charges for the associated load. Since the generator received LBC SO payments based on gross generation, it was equivalent to all generation output being supplied to the system. For consistency purposes, FIRM maintained the related load should be treated as if it was all supplied from the system and the DTS tariff should reflect this gross contract load. To avoid any future misunderstandings, FIRM submitted the Explanatory Memorandum should clearly indicate DTS cost responsibilities with a gross metering election.

1.1.2 Views of TCE

TCE offered comments upon the explanatory memorandum.

TCE noted that while EAL had included the Explanatory Memorandum ("Memorandum") as part of its filing, it was not clear whether EAL was seeking Board approval of this document. In any event, TCE had some comments/questions in relation to the Memorandum that it would appreciate responses to.

In relation to Question 2, page 2, EAL provided various scenarios as to how payments would be made for various LBC SO acceptance situations. While TCE found this very helpful, it was unclear whether or not a GFO would be receiving an Incentive Payment where it had a credit capacity of 100 MW and it had its facility in commercial operation on July 1, 2002 for all 100 MW. Presumably, the GFO would receive an Incentive Payment for the July 1, 2002 period (for the first tranche of 50 MW) and a further Incentive Payment for the six months prior to the December 2004 period for the second tranche of 50 MW. TCE requested the Board require EAL to make this clarification.

On page 3 of the Memorandum, EAL stated "An accepted Standing Offer will be a binding contract. Each such contract entered into as a result of the standing offer process will be for a term of 20 years". TCE required some clarification in this regard, too. TCE understood that the SO that would be commenced February 20, 2001 would relate to several zones and that credits for each of these zones would be posted concurrently.

However, if there were multiple bids accepted in multiple zones, it was not clear, how these contracts could be binding, if there was a bid down process. Furthermore, it was not clear what EAL would do in this situation. For instance, will EAL conduct bid downs in both zones concurrently? If bid downs in two zones are accepted concurrently, will EAL still have some discretion to determine which contract is "binding"?

The concern here is that EAL has maintained the ability to determine how to proceed with the SO for various zones once one zone has an accepted binding bid, yet it was not clear what happened when two bids in two zones were accepted.

Likewise, it was not clear what EAL would do if two zones concurrently received acceptances. If the single acceptances in two separate zones resulted in a binding contract, then presumably EAL had no discretion to determine if one acceptance would be binding and another not. TCE requested the Board direct EAL to incorporate such clarifications in their Memorandum.

On page 9, TCE noted EAL had indicated the following:

> At least two business days prior to commencing the Standing Offer process, the TA will provide the Qualified Persons with a timetable (via fax and the TA's web-site) specifying the date and time that the Standing offer will become effective, the opening LBC Rate offered, the size of increments by which the LBC Rate will be increased (if necessary), and the frequency at which the incremental increase to the LBC Rate will occur.

Since the Location Based Credit Entitlement Offer was presumably binding once an acceptance was submitted, a company submitting a bid may require internal corporate approvals prior to such acceptance. TCE submitted two days may be insufficient to get the necessary corporate approvals and would ask that the Board require EAL to provide this information one week prior to the SO; in order that potential bidding companies have sufficient time to obtain appropriate internal corporate approvals.

Finally, with respect to Question 5, p. 9, TCE requested that further clarification be provided in relation to the bid-down process. In particular, it was not clear to TCE whether the bid-down was a fax race such that whichever bidder sent in a fax acceptance won the bid-down, or; whether the 15 minute window acceptance would apply (i.e. if the bidders who tied can all submit acceptances within the 15 minute window and if more than one did, then there was another decrement with a further 15 minute window).

In reply, TCE supported the Coalition's request, with respect to Directions 4 & 6, that EAL provide a concrete schedule for the 2002 transmission development plan approval process. TCE also supported the proposal that the Transmission Administrator ("TA") address the Planning Criteria in one year and that reliability criteria be finalized for the 2002 transmission development plan.

TCE again supported the Coalition's comments relating to Direction 11. TCE would also appreciate the opportunity to provide input into the development of the Operational Guidelines for the Dispatch of TMR Generation.

TCE noted that FIRM had suggested changes to the Eligibility Payments. As FIRM's suggestions have only recently been raised, TCE maintained it was difficult for parties to test this suggestion at the point of reply submissions. TCE noted that the TA had included an Incentive Payment that was similar to that in the IBOC contract. TCE noted that the Eligibility Payment in the proposed LBC SO contract were similar to that in the approved IBOC contracts. Since the IBOC contracts have had the benefit of a full hearing process and approval, TCE supported the proposed LBC SO Eligibility Payment also being similar to that in the approved IBOC contracts. TCE also noted that FIRM had suggested the addition of the LBC SO rate to the benchmark rate. TCE noted that FIRM in particular stated that "Furthermore if there is a concern that the inclusion of the LBC SO credit in the benchmark rate will tend to increase the generator's standing offer acceptance level then a business case should be prepared and presented to substantiate this concern".

TCE had concerns with this proposal. Firstly, FIRM did not take into account that the Standing Offer commences in two weeks and parties are now filing reply submissions. Secondly, in Decision 2000-76, the Board provided considerable guidance on the Supplemental Payments with provisions to: revise the supplemental payment as a result of unforeseen circumstances, dispute resolution, and a dispatch process that ensures the TA pre-authorizes supplemental payments. TCE submitted that the proposed refiling appropriately set safeguards to ensure the TA had sufficient control over the Supplemental Payments.

1.1.3 Views of the Coalition

The Coalition commented upon a number of directives.

Direction 4 - EAL to Fully Address the Appropriate Planning Criteria and Direction 6 – Development Plan

The Coalition noted that EAL stated it would take "up to two years to achieve" the appropriate planning criteria. The Coalition was concerned that the planning criteria relied upon by EAL in the proceeding, and accepted by the Board in an "abundance of caution" should not be entrenched by the passage of time. The Board's expectation that EAL fully address the planning criteria for its ten-year transmission development plan did not appear to be unreasonable, particularly given the discussion this topic received during the proceeding leading to Decision 2000-76.

The Coalition requested that EAL provide a concrete schedule allowing this important issue to be determined in the approval process for the 2002 transmission development plan.

The Coalition proposed the Transmission Administrator seek to address the Planning Criteria in one year.

Further, in order to satisfy Direction 6 (Development Plan) it seemed that the "appropriate reliability criteria" must be established. The recommended reliability criteria should be at least finalized for the 2002 transmission development plan.

The Coalition claimed a critical component of Decision 2000-76 was that EAL submit an annual transmission development plan to the Board "for approval". This development plan was "at a minimum" to include the enumerated items (including "appropriate reliability criteria").

The Coalition noted that EAL's response to this Direction contained no commitment to actually submit this annual transmission development plan to the Board for approval. The Coalition requested that EAL make this commitment and describe when the annual transmission development plan, as described by the Board, would be submitted and how the approval process would, in EAL's view, proceed. The Coalition also reiterated its understanding that the development plan should not be a substitute for specific facilities applications.

Direction 11 - Operational Guidelines for Dispatch of TMR Generation

The Coalition noted that EAL stated it would not be able to complete these criteria until October 2001, saying, "these operating guidelines are not required in order to launch the Standing Offer". While the use of minimum hours was fine for payments under the Offer, the Coalition stated dispatch of the Facilities should be in accordance with operational guidelines and the actual transmission system needs.

The Coalition therefore agreed that it was not necessary for the refiling to have the operational guidelines in place, as long as Dispatch of the Facilities receiving incentives under the LBC SO was done in accordance with operational guidelines for dispatch of TMR generation. The Coalition also registered its understanding that it would have input into the development of these operational guidelines.

1.1.4 Views of ENMAX

ENMAX, while not submitting initial comments, did offer reply. With respect to the issues of incentive payments and eligibility payments, ENMAX was not supportive of the FIRM's recommendations. ENMAX stated that there was no justification for changing the incentive and penalty provisions. It was ENMAX's understanding that the penalty provisions proposed by EAL were similar to those extant in the IBOC process and should therefore be acceptable in the context of the LBC SO.

ENMAX also disagreed with FIRM's submission regarding supplemental payments. ENMAX did not support including the LBC SO credit in the operating cost benchmark determination. The payment of the LBC SO credit was distinct from the requirement of the TA to make a supplemental payment to the generation facility owner. The credit was payable under circumstances which were unrelated to those under which a supplemental payment was made and therefore ought to be excluded from the determination of the supplemental payment.

With respect to minimum annual hours, ENMAX generally supported the FIRM's recommendation that the TA be required to provide details of the business case that justified the elevated take-or-pay level in the initial years, but only to the extent that implementing this recommendation did not further delay the LBC SO.

2.2 Issues Arising from the Entitlement Offer (pro forma Contract)

2.2.1 Views of the Coalition

The Coalition commented upon the following terms.

Commercial Operation Date (168 hours of continuous operation)

The Coalition noted the term "Commercial Operation Date" or "COD" was defined in Schedule 1 as the date given by written notice once the Facility has generated "on a continuous basis over a period of at least one hundred and sixty-eight (168) hours …". It is a covenant under section 3.1 of the Offer that the COD not occur more than six months after the Required Commercial Operation Date (RCOD). As such, the Coalition noted failure to meet COD constituted an Event of Default, under section 13.1 of the Offer, which placed the facility owner at risk for termination and liquidated damages under section 13.4 of the Offer.

Under section 4.1(g) of the Offer, incentive rates were provided for in the event that the COD was achieved before the RCOD. This complied with the direction given by the Board for incentive payments for generation being in operation ahead of the required date.
The concern of the Coalition related to the requirement for 168 hours (or 7 days) of continuous operation at a 100% Energy Ratio. The Coalition noted that under most turn-key construction agreements with which its members are familiar, the completion requirement for a power plant is generally set at a less onerous standard than 168 hours of continuous operation at a 100% capacity factor. The Coalition was aware of seven days of operation being applicable for new technology and even then at a capacity factor of less than 100%.

In order to provide for symmetry with normal commercial arrangements for the construction and commissioning of power plants, the Coalition recommended that the definition of Commercial Operation Date be amended as follows to provide for a test that was more in line with commercial arrangements made with suppliers:

> …which notice cannot be given until the Facility has generated over a cumulative period of at least one hundred and sixty-eight (168) hours at an average Energy Ratio of not less than ninety-five (95%) percent. It is understood that during the test period, the Facility will normally be offering its electric energy into the Power Pool of Alberta at a price no greater than the Operating Cost Benchmark. All hours for which the Facility receives a dispatch order from the System Controller will contribute toward the test of one hundred and sixty-eight (168) hours. In the event that during the test period the TA requests the Facility Owner to offer electrical energy at a price that is less than the Operating Cost Benchmark, the TA will make Supplemental Payments in accordance with section 6.1(2).

Maximum Time to Commercial Operation

The Coalition noted Schedule 5 set out the maximum time to have a Facility in Commercial Operation after Dispatch Instruction in hours:

Coal Plant – 8 hours
Combined Cycle Gas Turbine Plant – 3 hours
Simple Cycle Gas Turbine Plant – 1 hour

These Maximum Times related to the covenant under section 3.1(m) of the Offer:

> Subject to Permitted Unavailability or Forced Outage (to the extent the Facility is subject to Forced Outage), upon receiving a Dispatch Instruction the Generating Facility Owner shall, subject to Good Electric Operating Practice, use best efforts to have the Facility in Commercial Operation by the time specified in the Dispatch Instruction, but in no event shall the time to get the Facility in Commercial Operation exceed the applicable Maximum Time to Commercial Operation as provided in *Schedule 5*. [emphasis added]

The Coalition also noted that pursuant to section 13.1, failure to meet the Maximum Time to Commercial Operation would be an Event of Default. The prescribed remedies under section 13.4 included termination, and liquidated damages under both 13.4(c) and 13.4(d), as well as realization on the Prudential Security.

Accordingly, the Coalition maintained a generator could be complying with Good Electric Operating Practice and using its best efforts to have the power plant on line specified in the Dispatch Instructions. However, despite these best efforts, if the inflexible deadlines were not met, the drastic remedies of termination and exposure to significant amounts of liquidated damages were stipulated. Even if an operator made an error, the drastic remedy of termination seemed to be going far beyond what was necessary. The Coalition suggested a financial penalty was all that was necessary to encourage compliance.

The Coalition further maintained exposure to termination in these circumstances was not commercially reasonable. The generator should have an incentive to comply with Dispatch instructions. The Coalition submitted that exposure to a penalty (for example $50 per MW.h) for each hour over the maximum would be ample incentive for a generator to meet the Maximum Time limits. Providing for terminations when, despite good faith efforts, the arbitrary time limits prescribed in Schedule 5 have not been met only added to the risk profile of the LBC SO, and for no foreseeable countervailing benefit. It was recommended that the sole penalty for a breach of section 3.1(m) should be a penalty of $50 per MW.h for each hour over the maximum.

Approvals

The Coalition noted that under section 10.1(c)(ii), the generator must represent and warrant as of the Acceptance Date, that performance of the Agreement does not require any consent, authorization or approval under any Legislation,[4] other than those required in connection with the Approvals.

Approvals are defined as:

> **"Approvals"** means, collectively, the AEUB Order, the HEEA Approval and the EPA Approval.

The Coalition noted that under section 17 of the *Hydro and Electric Energy Act* the owner or operator of a power plant shall not connect his power plant to a transmission line unless the connection is in accordance with an order under section 17. Since section 17 is not included in the defined Approvals, section 10.1(c)(ii) would place Facility Owners in breach of the agreement if this necessary approval were not in place at the time of the Acceptance Date.

The Coalition also noted that other approvals under Legislation might well be required for individual power plants. The obtaining of defined Approvals (EPA Approval and HEEA Approval) was a condition precedent under section 7.1 of the Offer.

The Coalition proposed that a more realistic provision be provided for the obtaining of approvals to reflect that individual projects may require more particular approvals.

The Coalition proposed that the definition of Approvals be amended to read as follows:

> **"Approvals"** means, collectively, the AEUB Order, the HEEA Approval, the EPA Approval and all other orders, permits, approvals and consents required by Legislation in order to construct and operate the Facility as are identified in the Construction Schedule.

The Coalition suggested Section 7.1(a) should also be amended by adding the following to the end of section 7.1 (a)(iii): "… and the Generating Facility Owner has obtained all other Approvals on terms satisfactory to the parties as contemplated under *Section 9.1*." In this way, it would be the obligation of the generator to disclose the approvals it required in the Construction Schedule, and pursue those approvals with diligence.

However, the generator ought not to take on the risk of governmental action which was beyond its control nor represent and warrant that it has all approvals as of the Acceptance Date when it was a virtual certainty that not all the approvals would by then be in hand.

<u>Target Hours</u>

The Coalition noted that Target Hours were defined in section 4.1(b) as the difference between the hours in a Month for which the Facility is Dispatched and the total number of hours in which there was a Permitted Unavailability or the occurrence of Force Majeure during the set hours the Facility was Dispatched.

[4] A broadly defined term, which includes regulation, guidelines, directions and standards.

The term "Dispatched" was defined to mean "an instruction given to the Generating Facility Owner by the System Controller requiring the Generating Facility Owner to have the Facility in Commercial Operation pursuant to this Agreement.

The Coalition believed that the principle surrounding the calculation of Target Hours should be only those hours where the Transmission Administrator required the Facility to run for transmission constraint reasons. The current definition of Dispatch introduced leeway to consider non-binding hours as target hours. This tended to make the energy ratio more onerous, and was not consistent with the principle that target hours be restricted to those hours where there was actually a transmission constraint which required the facility to run.

The Coalition requested that the term "Dispatched" in section 4.1 (b) be qualified to restrict it to times when the Facility "is required to be Dispatched due to binding transmission constraints". Again, the Dispatch should be based on the Transmission Administrator's operational guidelines (for the reasons stated in section 1.2 above).

Operating Cost Benchmark

For greater certainty, the formula (7.5 GJ/MW.h) was understood by the Coalition to be based on higher heating value gas.

Reciprocal Representations and Warranties

The Coalition proposed that the Transmission Administrator provide reciprocal representations and warranties to those which the Generating Facility Owner was obliged to provide under section 10.1(a), (b) and (c). The Coalition submitted that it was only reasonable for the TA to make these sorts of representations and that they would assist in a smoother financing of the power plants.

Events of Default, Termination Rights and Cure Period

The Coalition noted that Article 13 enumerated events of default, termination rights and cure periods and maintained project lenders and generators would carefully scrutinize these provisions.

The Coalition proposed a number of amendments that it claimed would preserve the incentive of the generator to comply while minimizing the scope for arbitrary terminations, which could chill participation in the LBC SO. They were as follows:

Section 13.1(a)
This section stipulated that failure to perform and observe any of the covenants in sections 13.1 or 16.1 or a breach of a representation and warranty in section 10.1 was an Event of Default. The Coalition submitted there should be a materiality test in section 13.1(a) and (b). It proposed that non-material breaches should not give rise to the onerous

consequences of an Event of Default, and therefore that the word "material" qualify the word "failure" in section 13.1 (a) and the word "breach" in section 13.1 (b).

Section 13.1(f)
An event of default was the Generating Facility Owner failing to comply with "any of the date(s) and remedial action(s) set out in the Recovery Plan". Under this provision, if a single milestone were missed by one day, an Event of Default could be triggered. The Coalition proposed that the following qualifier be added to section 13.1(f):
… and the failure to comply with such date(s) and remedial action(s)will have a material adverse effect on the Recovery Plan.

Section 13.2(f)
In this section, the Cure Period ended upon the Facility being restored to 90% of the average Energy Ratio over a three-month rolling period or the expiration of nine months from the date the Generating Facility Owner was required to provide the Recovery Plan. The Coalition was concerned about a case where a Generating Facility Owner was in the seventh month of its Recovery Plan, and then restored the Facility so that it generated over a 90% level for the eighth and ninth month of the Cure Period. The Coalition assumed that in these circumstances, the Generating Facility Owner would be regarded as having restored the average Energy Ratio of the Facility to ninety (90) percent.

For greater certainty, the Coalition proposed that another event be added to 13.2(f):
(iii) the average Energy Ratio of the Facility is restored to ninety-five (95) percent over any one (1) month period.

Section 13.4(h)
The purpose of this provision was to provide the Transmission Administrator with the ability to deal with a "lemon" power plant. The concern the Coalition had with the existing provision in section 13.4(h) was that if a generator promptly cured problems (for example within a month), it still must submit a Recovery Plan. Having one "strike" against it for an inconsequential event, the generator would be placed at risk of termination if it happened again.

The Coalition proposed the following change to section 13.1 (h):
(h) After Cure Periods extending in aggregate for a 12 month period, the Facility has had an average Energy Ratio of less than ninety (90) percent for any consecutive three (3) Month rolling period.

2.2.2 Views of TCE

TCE offered the following comments with respect to specific sections of the Location Based Credit Entitlement Offer.

Section 4.1(f)

TCE supported the addition of an Incentive LBC Rate, as set out in the EUB's Decision 2000-76 at p. 92, "Eligibility for incentive payments for generation being in operation of the required date up to 6 months early, similar to the IBOC contract". In reviewing section 4.1(f) of ESBI's refiling, it appeared to TCE that this provision would result in Incentive Payments being made in accordance with section 4.1(b) in that the Incentive Payment could be reduced based on the Energy Ratio (if less than 95%). TCE submitted that removing the wording "as determined pursuant to the scale set out under Section 4.1(b)" would resolve this issue.

Section 5.1(b)(ii)

With respect to the definition of "Total Requested Hours"; TCE submitted that if a Facility was unable to respond to Dispatch as a result of Force Majeure, those hours should not be deducted from the Annual Minimum Hours. The Generating Facility Owner ("GFO"); according to the definition of "Target Hours" in section 4.1(b)(iv)(D), did not appear to be receiving any LBC Payments during Force Majeure. TCE maintained that to leave the provision as it was could result in a reduction of the Annual Minimum Hours paid to a GFO during Force Majeure, which may be out of the control of the GFO. As such, TCE suggested that the words "or Force Majeure" in the second sentence of the definition of "Total Requested Hours" be moved to the end of the entire second sentence (following the words "Permitted Unavailability").

Section 7.1(a)(iii)

TCE noted that in EAL's Explanatory Memorandum, they acknowledged at page 8 that "A Qualified Person's proposed generation facility may be located outside of the applicable Standing Offer zone provided that the generator will be interconnected to the AIES within such zone via a wholly dedicated transmission facility". TCE stated EAL was cross-examined by the Coalition on the issue of whether a generator outside the province would qualify for a LBC SO, if it had the appropriate dedicated transmission line (see Transcript Volume 1 pages 23 & 24 and paragraph 24 of page 8 of EAL's Evidence). Presently, Section 7.1(a)(iii) has as a condition precedent, that the GFO obtain EPA Approval and HEEA Approval, on terms satisfactory to the Parties, in accordance with section 9.1. The definitions of "EPA Approval" and "HEEA Approval" in turn related solely to the "Facility" which was defined to mean the generating unit.

TCE had a few concerns with the wording of Section 7.1(a)(iii). Firstly, either or both EPA Approval and HEEA Approval may not be required if the generating unit is located out of the province. Secondly, the definitions of the EPA Approval and HEEA Approval did not extend to include the transmission line that may be required for a generating unit to provide electricity into the constrained zone. TCE claimed the necessary permits for the transmission line should also be a condition precedent as the transmission line would be a necessary component of the facility reducing constraints in the zone.

TCE recommended revising section 7.1(a)(iii) to read "the Generating Facility Owner has obtained the necessary environmental or other approvals required for the Facility to commence Commercial Operation, on terms satisfactory to the Parties as contemplated under Section 9.1."

Section 12.3

TCE noted that there appeared to be a few typographical errors to the second sentence, which TCE believed should read "The Generating Facility Owner shall have one year from the date of payment to commence a dispute, otherwise the amount paid shall be deemed conclusively to be correct".

Section 19.2

With respect to Section 19.2(a) TCE suggested that EAL clarify if the "material change in the Supplemental Payment formula" must actually be a material change in the costs that were covered by the Supplemental Payment. Furthermore, section 19.2(a) referred to Section 6.1(c), which did not exist. Presumably, it should refer to Section 6.1(a)(i).

With respect to Section 19.2(b), TCE suggested that the words "and Supplemental Payment formula" be added at the end of the last sentence to achieve consistency with Section 19.2(a).

In reply, TCE supported the Coalition's comments with respect to section 2.2 of the Location Based Credit Entitlement Offer ("Entitlement Offer"). In particular, TCE supported the suggestion that a penalty of $50/MWh would be sufficient incentive for a GFO to meet the Maximum Time.

TCE also believed that further clarification in section 2.5 of the Entitlement Offer would be useful so that it was understood that the 7.5GJ/MWhr is based on the higher heating value of gas.

2.2.3 Views of ENMAX

ENMAX agreed with the Coalition that failure to meet the maximum time to have a Facility in Commercial Operation after a Dispatch should result in a financial penalty rather than termination, as set out in section 2.2 of the Coalition's submission. ENMAX acknowledged that EAL must have the tools necessary to encourage compliance but in this instance the significant financial penalty was sufficient.

ENMAX also agreed that the definition of "Approvals" ought to be amended to include any required regulatory approvals, as suggested by TCE and the Coalition (set out in section 2.3 of the Coalition's submission and on page 2 of TCE's submission).

ENMAX, however, disagreed with TCE's submission with respect to section 4.1(f) and did not support TCE's recommendation to remove the phrase "as determined pursuant to the scale set out under Section 4.1(b)." ENMAX supported the present language of section 4.1(f) and noted that EAL's proposed language would result in the similarity between the Invitation to Bid on Credits ("IBOC") and the LBC SO expected by the Board in its Direction 16, set out on pages 91—92 of Decision 2000-76. ENMAX submitted that TCE's recommended change would detract from the similarity in language.

2.2.4 Views of EAL

In reply EAL noted that the Coalition had recommended a series of changes to the pro forma contract. As a result EAL made the following changes to the revised pro forma contract filed with its comments. The item numbers refer to Appendix A which was attached to EAL's reply and attached to this decision as Appendix A as well.

- Commercial Operation Date (§2.1) — Item 7
- Maximum Time to Commercial Operation (§2.2) — Item 1
- Approvals (§2.3) — Item 2
- Representation and Warranties (§2.6) — Item 3
- Events of Default, Termination Rights and Cure Period (§2.7)
    - materiality (Contract Section 13.1(a)) — Item 4
    - materiality (Contract Section 13.1(f)) — Item 4
    - end of cure period (Contract Section 13.2(f)) — Item 6
    - event of default regarding cure period (Contract Section 13.1(g)) — Item 5

EAL stated that at section 2.4 of their the Coalition asked that the term "Dispatched" in Section 4.1(b) of the contract be qualified to restrict it to times when the Facility "is required to be Dispatched due to binding transmission constraints." EAL understood that the Coalition has agreed with EAL that this change is not required based on the requirement for Board approval of the operating guidelines that will be used to determine when to issue a Dispatch Instruction.

EAL confirmed that the 7.5 GJ/MW.h in the Operating Cost Benchmark formula is to be based on higher heating value gas.

EAL noted that the Coalition discussed planning criteria and the transmission development plan in section 1.1. EAL proposed to develop separate, comprehensive planning criteria with respect to the bulk, non-bulk, and POD components of the transmission system. Planning criteria for the non-bulk and POD components had not been formally developed before now. EAL stated a first draft of these criteria was contained in the *Transmission Development Plan 2001-2010*, published for comment[5] and public consultation in December 2000. (For clarification, EAL interpreted the Coalition's reference to the "2002 transmission development plan" to mean the plan that would be published in December 2002, covering the years 2003 through 2012.)

EAL hoped to reach a high degree of consensus before submitting the new planning criteria to the Board for approval. However, given the diverse interests of industry stakeholders, EAL believed that a significant amount of time might be required to do so. EAL is prepared to commit to a process whereby it would submit planning criteria for approval by the end of 2001.

EAL noted that the Transmission Planning Committee (TPC), chaired by EAL, was one mechanism through which industry stakeholders could provide their input to the planning process. EAL proposed that the TPC would be used to develop new planning criteria. TPC meetings are held quarterly, with the first meeting set for February 14, 2001.

[5] The Development Plan requested written comments by the end of March 2001

EAL stated that it would file its transmission development plans for approval at the end of each year. EAL suggested the associated regulatory proceedings be written ones that focus on the policy components rather than on individual facility additions. This approach was proposed because the development plan was a "living" document, subject to constant change. Approving the plan in its entirety would not allow facility proposals to respond to changing requirement from supply and demand customers. EAL concurred with the Coalition's view that each specific facility should continue to be subject to a separate facilities application.

EAL noted that TCE had submitted the incentive payment under Section 4.1(f) of the pro-forma contract should not be determined pursuant to the scale set out under Section 4.1(b). EAL disagreed because it was appropriate that the Generating Facility Owner (GFO) meet the performance requirements in order to receive payment. The performance requirements set out in Section 4.1(b) (sliding scale payments formula) should be applicable for all hours that the Facility received a Dispatch Instruction, regardless of whether this was after the RCOD or before it (in the case of early COD).

EAL also noted that TCE suggested Total Requested Hours should exclude hours when the Facility is Dispatched during an event of Force Majeure. EAL stated the definition of Total Requested Hours must include hours when the Facility is Dispatched during an event of Force Majeure in order to prevent payments from the Transmission Administrator to the GFO during such events. It was normal business practice that a service provider did not receive payments for services that it could not provide. Just as the GFO would not receive the Monthly LBC Payment during an event of Force Majeure, neither should it receive the Annual Minimum Payment during such an event.

EAL stated the corrections and clarifications requested by TCE in respect of Sections 12.3 and 19.2 of the contract had been made.

EAL noted that TCE had requested clarification regarding eligibility for Incentive Payments when a GFO accepts a Standing Offer for two Required Commercial Operation Dates (RCODs) and the full Credit Capacity is available before the first RCOD. EAL explained the GFO would be eligible for an Incentive Payment for the first Tranche during the six-month period leading up to the first RCOD, and an additional Incentive Payment for the second Tranche during the six-month period leading up to the second RCOD. That is, the Incentive Payment was applicable to each RCOD separately.

With respect to TCE's request for clarification as to how the Transmission Administrator would determine if an Acceptance of a Standing Offer was binding. This would be related to when several Acceptances occurred in separate zones during the first 15 minutes of a Standing Offer (or the first 15 minutes following an increase to the offered LBC Rate). EAL explained it would structure the Standing Offer such that the start times in each zone were staggered, that is, such that no 15-minute period in one zone will overlap with a 15-minute period in another zone.

EAL stated that it would provide a timetable one week prior to the start-date of the Standing Offer (i.e., February 13).This timetable would specify the date and time that the Standing Offer becomes effective, the opening LBC Rate, the size of the increments in the LBC Rate, and the frequency of the increments.

EAL also noted that TCE had expressed concern that the bid-down process could become a "fax race such that whichever bidder sends in a fax acceptance wins the bid-down." EAL confirmed that a bid-down process would not be a fax race. EAL explained that at the time of the bid-down process, the TA would specify the time requirement for the bidders to submit their Acceptances to the TA. If the fax line was busy due to another bidder submitting its Acceptance, a bidder may submit its Acceptance immediately upon the fax line becoming available. All otherwise-valid Acceptances received by the TA within the time requirement would be valid.

EAL noted that FIRM recommended that "there be closer symmetry between the incentive and penalty provisions by increasing the daily eligibility payment. This would be accomplished by assuming an LBC Rate or using the average of the existing IBOC Rates for calculation purposes or using the same 2 times the LBC SO Rate formula."

EAL stated it considered making the Eligibility Payment equal to twice the amount of the LBC Rate, as FIRM recommended, versus using the same Eligibility Payment provided in the IBOC contracts. EAL considered that the latter was already approved by the Board and provided a sufficient deterrent for missing the RCOD.

EAL also stated that making the Eligibility Payment equal to twice the amount of the LBC Rate would not be symmetrical with the Incentive LBC Rate. Using the LBC Rate as the reference point, EAL explained that the Generation Facility Owner (GFO) gained an additional amount equal to the LBC Rate for achieving its COD before the RCOD. On the other side, the net loss to the GFO for missing the RCOD would be equal to a charge of twice the LBC Rate, in addition to the lost opportunity of not receiving the LBC Rate.

EAL noted that FIRM submitted that the LBC Rate should be included in the Operating Cost Benchmark because it would be an offsetting factor to the GFO's operating costs. Furthermore, FIRM submitted that if there was a concern that inclusion of the LBC Rate in the Operating Cost Benchmark would cause the GFO's required LBC Rate to be higher, then a business case should be prepared to substantiate this concern. EAL confirmed its concern that including the LBC Rate in the Operating Cost Benchmark would cause the GFO's required LBC Rate to be higher. EAL submitted that the logic for this concern was straightforward and did not require a detailed business case.

EAL explained the number of hours during the 20-year term of the contract for which a GFO expected to receive the LBC Rate payment was a factor that determined the LBC Rate that the GFO would require in order to make its generation project economic. Including the LBC Rate in the Operating Cost Benchmark meant that the GFO would effectively forfeit the LBC Rate payment during hours when the pool price was below the benchmark. The GFO would, therefore, reduce the expected number of hours that it would receive the LBC Rate, causing its required LBC Rate to increase in order to keep its project economic. Due to the high level of uncertainty encountered in forecasting the number of hours over a 20-year period that the pool price would be below the Operating Cost Benchmark, EAL expected the GFO would build in a risk premium, resulting in a further increase in its required LBC Rate. This was the same reason that EAL gave to the Board during the LBC SO hearing for the inclusion of the Supplemental Payments. Spreading the risk over the TA's revenue requirements would result in a lower LBC Rate by reducing the GFO's risk premium, which would in turn result in lower overall costs to the Transmission Administrator's customers. EAL's view was that the Board accepted this position in its decision, and did not require a detailed business case.

On the subject of gross metering, EAL noted FIRM submitted that the *gross* load associated with the LBC SO generator should be subject to charges under tariff Rate DTS. EAL maintained this issue has already been dealt with by the Board, which ruled that if the generator chooses the gross metering option, Rate STS would be applicable for the gross generation but Rate DTS will be applicable only for the net load.

EAL noted that FIRM also submitted that the TA should provide details of the business case that justified its proposed Minimum Annual Hours. EAL offered the following explanation of its proposal, but was concerned that releasing the details would reveal the Transmission Administrator's pricing expectations to potential LBC SO bidders. That could result in higher-than-necessary credits being paid to GFOs.

EAL explained it used a number of scenarios to examine the trade-off between Minimum Annual Hours and the LBC SO Rate that would be required by the GFOs. The trade-off existed because, as the Minimum Annual Hours increased, a GFO's revenue rose (for a given LBC Rate) and the certainty of that revenue increased. This combination allowed the GFO to accept a lower LBC Rate and still obtain the revenues necessary to support the generation project. On the other hand, the higher the Minimum Annual Hours, the more likely it was that the Transmission Administrator would pay the LBC Rate in hours when the generator was not required.

EAL further explained the analysis conducted by EAL looked at the LBC Rate that would be required to recover the investment needed for a "typical" generator under several Minimum Annual Hours scenarios. The number of actual dispatch hours it would take to cause the lower-minimum, higher-rate scenarios to be more expensive than the higher-minimum, lower-rate scenarios was then determined. The results showed that the number of hours was relatively small—less than 10% of the total hours in a year. Such small margins created a high level of risk that choosing a scenario with lower Minimum Annual Hours would result in higher costs.

Finally, EAL commented upon two issues that arose at its meeting with the parties on February 8, 2001. EAL stated that it was proposed that the definition of "Forced Outage" allows for generator de-rates. EAL did not support such a change because it would significantly increase the burden of administering the contract. Instead, EAL proposed to accept that a Dispatch Instruction would be deemed to have been satisfied if the output of the Facility exceeded 90% of its Credit Capacity. EAL maintained this provision provided flexibility for de-rates and aligns dispatch requirements with the current Power Pool rules.

EAL also stated it was proposed that, due to the increasingly tight time requirement to meet the RCOD, the generator should be allowed to trigger Cure Periods within 24 months from the date of an Acceptance without having them count against the aggregate Cure Period limit of 365 days. (The 24 months represented construction time.) EAL considered this provision to be unnecessary, as there was already sufficient flexibility around Cure Periods (see Item 5 of Appendix A).

2.3 Comments on Revised Filing (Settlement) of February 12, 2001

2.3.1 Views of the Coalition

With respect to section 3.1(c), the Coalition stated that the provision required the Generating Facility Owner (the "GFO") to provide the Transmission Administrator (the "TA") with a series of documents within a very short time period following the Acceptance Date. In the case of a Facility that has an RCOD of less than two years following the Acceptance Date, the period for providing these documents was 25 Business Days. In many instances, obtaining these documents within such a short period of time is not relevant to the Construction Schedule or otherwise on the critical path to the achievement of COD prior to RCOD. In other instances, it is not clear what is intended.

Given that a failure by the GFO to observe any of the provisions of Section 3.1 may be construed as an Event of Default pursuant to Section 13.1, the Coalition believed that subsection 3.1(c) required amendment as follows:

(g) references to "binding letters of intent" was unclear. Generally speaking, a letter of intent is not binding but rather an expression of intent. It was not clear to the Coalition what was meant by the mixed phrasing "binding letter of intent". We would request that the reference to "binding" be deleted as an ordinary letter of intent seems more reasonable in the restricted time allowed;

(h) the requirement for evidence of insurance for the "duration of the construction <u>and operation</u>" seemed unnecessary within 25 Business Days following the Acceptance Date. In any event, it did not seem reasonable to require the GFO to obtain the insurance as it related to a 20 year term of operations within this time period. The Coalition requested that subsection 3.1(c)(vii) be deleted in its entirety, but at a bare minimum the phrase: "and operation" should be deleted;

(i) subject to its comment regarding "binding letters of intent" the Coalition could accept subsection 3.1(c)(viii) if the phrase: "and maintenance" was deleted. Again, not only was it unreasonable to require an agreement in 25 Business Days governing the maintenance of the Facility (presumably for the duration of the Agreement, although this was not clear), but many GFOs would choose to maintain the Facility using their own employees and therefore would never need to enter into such a maintenance agreement; and

(j) presumably the requirement for the documents set forth in subsection 3.1(c) related to the TA's need to assure itself that both the Construction Schedule would be adhered to and COD for the particular Facility would be achieved by the RCOD. With this in mind, the GFO required protection that a failure to provide any of this documentation within 25 Business Days, which failure did not jeopardize the achievement of COD, could not be used against the GFO for the purposes of determining the occurrence of an Event of Default. Therefore, at the end of subsection 3.1(c), the Coalition requested that the following text be added:

> It shall not be reasonable for the Transmission Administrator to require receipt of any of the specific documentation referred to in this subsection 3.1(c) by the applicable deadline specified above unless the failure of the Generating Facility Owner to provide same will, or in the reasonable opinion of the Transmission Administrator is likely to, cause a delay in the achievement of COD on or before the RCOD.

The Coalition noted that section 3.1(e)(I) required that if a GFO wished to interconnect to the Transmission System at a voltage lower than 240 kV, it must have the approval of the TA. On February 1, 2001 the TA advised members of the Coalition that no Acceptance which relied upon a connection at a voltage lower than 240kV could be made unless the TA had previously approved such lower voltage. The Coalition requested that the Board ensure that the TA puts in place a process which allowed for prompt approval of lower voltage connections and thereby ensured all Qualified Persons could participate in the Entitlement Offer Process at its commencement.

The Coalition stated that section 3.1(e)(iv) required that the GFO connect the Facility to the System at an interconnection point as approved in writing by the TA. Section 5 of Schedule 2 (Response Information Required) required a GFO to specify its desired point of interconnection to the System.

The Coalition maintained it should be made clear that the TA cannot "accept" an Acceptance and then impose an interconnection point other than that specified in the GFO's filed Schedule 2. The Coalition further maintained that the Acceptance Date is not triggered until the TA provides the GFO with written acknowledgement accepting such interconnection point. For example, the period for the performance of the documentary filing requirements specified in subsection 3.1(c) could not be triggered until the GFO knew exactly where its interconnection point would be.

Therefore, the Coalition requested that subsection 3.1(e)(iv) be rewritten to read:

> the Facility shall be connected to the System at the interconnection point specified in the Generating Facility Owner's Offer in the form of Schedule 2 attached hereto, subject to the Transmission Administrator's written acceptance of such location, or the Generating Facility Owner's acceptance of an alternate interconnection point that may be specified by the Transmission Administrator;

Section 3.1(g)(i) required that the Facility be compatible with the TA's Model Validations and Audit System ("MVAS"). It was the Coalition's understanding that the constituents of the MVAS were not static and may be required to change from time to time. The Coalition maintained the costs associated with such changes might not in all instances be fairly borne by the GFO.

Therefore, the Coalition requested that its compatibility obligation in respect of the MVAS be altered by rewording subsection 3.1(g)(i) as follows:

> …be compatible with the Transmission Administrator's MVAS as it exists at the date hereof, and shall further use all reasonable commercial efforts to implement any changes in the Transmission Administrator's MVAS as approved from time to time by the AEUB, provided that the costs associated with such changes shall be borne by the Generating Facility Owner only to the extent so directed by the AEUB;

The Coalition noted that section 3.2 was a new provision inserted by the TA for the purpose of ensuring that a GFO was strongly induced to respond to Dispatch Instructions as promptly as possible.

The Coalition observed that this was an extremely onerous provision, which fundamentally altered the balance of risk under the Agreement for any GFO. The impact of this provision was to impose a $500/MW per hour penalty (which quickly doubled to $1,000/MW) for every hour following an unexcused failure to commence Commercial Operation following the Maximum Time to Commercial Operation for the particular Facility. This penalty was uncapped so that in six hours (in the case of a simple cycle gas turbine plant) this penalty would exceed the $5,000/MW in Liquidated Damages that were payable pursuant to Section 13.4 following an Event of Default. If the Facility was offline as a result of an outage for which the GFO was deemed responsible, then a long-term outage could bankrupt a project.

The Coalition considered for an example a 30 day unexcused outage of a 100 MW Credit Capacity Facility. After two hours the penalty rate is $1,000/MW. Thirty days at this rate netted a payment of $72,000,000.

It seemed very late in the day for the TA to be proposing a provision, which offered such potentially catastrophic consequences for the GFO. The Coalition stated it first discussed this provision with EAL during the February 8, 2001 meeting and did not agree with its imposition.

As such, the Coalition had a number of suggestions to propose in respect of it. They were as follows:

(k) the reference in subsection 3.2(a) to "best efforts" should be deleted and replaced with "reasonable commercial efforts". A "best efforts" obligation could be construed as requiring a party to spend money to achieve a particular goal until such time as the party was bankrupt. Obviously this was unacceptable from the perspective of any GFO;

(l) the $500/MW per hour quantum of the penalty prescribed in subsection 3.2(b) was clearly unreasonable, even before taking into consideration its doubling pursuant to subsection 3.2(c). The Coalition believed that a value of an order of magnitude of $100/MW per hour would be more reasonable. If the TA required the doubling prescribed in subsection 3.2(c), then the quantum of the number in subsection 3.2(b) should be $50/MW;

(m) there must be an aggregate cap on the amounts payable by any GFO pursuant to Section 3.2. The Coalition noted that for an Event of Default, the Liquidated Damage ceiling pursuant to Section 13.4 was $5,000/MW of Credit Capacity. That Liquidated Damage amount followed an Event of Default. A GFO's maximum liability pursuant to this Section 3.2 should not be allowed to exceed such Liquidated Damage amount for any individual failure pursuant to Section 3.2. The Board might also consider an aggregate cap for the total claims to be made by the TA pursuant to this Section 3.2;

(n) the last sentence of subsection 3.2(b) was particularly offensive in view of the quantum of the penalty proposed by the TA. A failure of 30 seconds in an hour on 100 MW of Credit Capacity ought not to result in an additional $100,000 of penalty. If the TA was fixated upon round numbers, the Coalition requested that in such instances the TA round <u>down</u> to the nearest complete hour of delay in Commercial Operation. Otherwise the Coalition would accept a proportional quantification of these penalties on the basis of five minute increments within any hour;

(o) as already noted, the doubling of the penalty amount prescribed in subsection 3.2(b) pursuant to subsection 3.2(c) was unacceptable to the Coalition without both: (i) a significant reduction in that initial quantum; and (ii) a cap on the aggregate liability of the GFO for such penalty;

(p) the payment obligations of the GFO were triggered on the entire amount of the Credit Capacity notwithstanding that the GFO may suffer only a shortfall of a few MW of its overall Credit Capacity obligation. The Coalition believes that the System was better off receiving a high percentage of the Credit Capacity requested by the TA at any particular time even if the entire Credit Capacity was unavailable. Therefore, the TA should be required to accept an amount of available capacity less than the Credit Capacity and any penalties otherwise payable pursuant to Section 3.2 should be based solely upon the <u>shortfall</u> in capacity, not upon the entire Credit Capacity. In other words, if a GFO suffered a de-rating of 5% on a Credit Capacity of 100 MW, the System was better off receiving the 95 MW that the GFO could provide and, if provided, the GFO should only pay the penalty prescribed in subsection 3.2(b) to the extent of the 5 MW shortfall not the entire Credit Capacity; and

(q) the imposition of Section 3.2 has required the Coalition to reconsider carefully the definition of "Forced Outage" as set forth in Schedule 1. Based upon our review of that definition and its implications for this Section 3.2, the Coalition believed that the reference to Good Electric Operating Practice within such definition was not

> reasonable. If an outage was not to be construed a "Forced Outage" if the GFO has breached any aspect of Good Electric Operating Practice, then the potential for a GFO to be second-guessed after a Forced Outage, and then being subject to liability pursuant to Section 3.2, was enormous. On this basis, the Coalition believed that the appropriate standard for determining what constituted a Forced Outage was not the adherence to the relatively high standard of Good Electric Operating Practice but rather one where any outage should be a Forced Outage unless the GFO's acts or omissions in respect of such outage constituted gross negligence or willful misconduct. Otherwise, a comparatively trivial operator error or misjudgment could, after the fact, be construed as not complying with Good Electric Operating Practice and as a result could expose a GFO to the brand new penalties proposed by the TA pursuant to Section 3.2. The Coalition requested the deletion from the definition of "Forced Outage" of the phrase: "which could not have been avoided through the use of Good Electric Operating Practice" and its replacement with the phrase: "other than those resulting directly from acts or omissions of the Generating Facility Owner which constitute gross negligence or willful misconduct".

With respect to section 7.1(a)(iv) the Coalition noted that in a letter dated January 31, 2001 a request made to provide a broader reference to the Approvals referred to in subsection 7.1(a)(iv) rather than merely the EPA Approval and the HEEA Approval. The inclusion of the reference "(or equivalent approvals)" was inadequate to address the Coalition's concerns. The Coalition stood by its submission of January 31, 2001 that this provision be changed to read that: "the Generating Facility Owner has obtained all Approvals on terms satisfactory to the Parties as contemplated under Section 9.1."

Then, in conjunction with this change, the Coalition reiterated their request to have the definition of "Approvals" amended in Schedule 1 to read as follows:

> **"Approvals"** means, collectively, the AEUB Order, the HEEA Approval, the EPA Approval and all other orders, permits, approvals and consents required by Legislation in order to own, construct and operate the Facility as are identified in the Construction Schedule.

The Coalition stated that section 12.3 prescribed that the GFO had one year following its receipt of any payment from the TA to dispute the amount of such payment or such payment would be conclusively deemed correct. In contrast, the TA reserved for itself in subsection 17.2(c) a period of six years to audit all books, records and other information relating to the Facility and to seek adjustments as a result of such audits. The Coalition believed that there was no particular reason for the audit periods afforded to each of the respective parties to be so different.

The Coalition believed that the audit periods for both parties should be either: (i) two years; or (ii) two years following the end of the calendar year to which the particular payment or information, as the case may be, related. The Coalition's position was based upon both typical industry practice and a belief that there was no reason for one party to have an audit period six times longer than it was prepared to grant to the other.

The Coalition noted that section 13.1(g) was a new section in which the TA had added a provision specifying that if the Facility has had in the aggregate six Cure Periods, then if its Energy Ratio dropped below 90% for any consecutive three Month period thereafter, an Event of Default would have occurred.

Given the length of the term of the Agreement, this meant that a Facility which had a series of problems early its Commercial Operation may be subject to termination notwithstanding the fact that its operations for a number of years had exceeded 90% by a considerable margin.

This essentially provided the TA with an unnecessary additional trigger for terminating the Agreement that it needed now but may not need or want later on in the Facility's life. The Coalition believed that this was inappropriate. The Coalition believed that subsection 13.1(g)(iii) should be deleted to remove the reference to the total of six Cure Periods as a trigger for an Event of Default.

If, however, the Board would not accept this proposal, then at a bare minimum, the Coalition requested that the TA not have the benefit of subsection 13.1(g)(iii). If notwithstanding that there have been six Cure Periods and the Facility has an average Energy Ratio of less than 90% for any consecutive three Months period, the Facility nevertheless has had an average Energy Ratio of 90% or greater for either:

(i) the prior two year period; or
(ii) the entire life of the Facility from the COD to current date.

The Coalition's strong preference was that the only restriction on Cure Periods should be that prescribed in subsection 13.1(g)(ii), which was an aggregate 365 days. As a refinement to that aggregate duration of Cure Periods, the Coalition asked the Board to consider adding a provision for a "run-in period", during which any necessary Cure Periods did not count toward the 365 day total.

It was in the interest of the System Security to have any Facility reach its COD as soon as possible including, if possible, prior to the RCOD. A GFO was disincented from having COD occur prior to the RCOD if it risked consuming the aggregate 365 day total of the Cure Periods by accelerating its COD. Rather, it would defer the declaration of COD until it could be certain that it has had a satisfactory run-in.

Therefore, the Coalition proposed that the 365 day aggregate duration of all Cure Periods after which an Event of Default could be declared by the TA not commence until a date six months following the earlier of either COD or RCOD. After such six-month run-in period, the 365-day counter would begin. As a point of reference, this proposed six month run-in period would replace the twenty-four month proposal made by the Coalition to EAL in this regard in the meeting on February 8, 2001.

Finally, the Coalition noted that section 13.4 specified remedies to which the TA was entitled following an Event of Default. Such remedies were based upon the declaration of the TA on notice to the GFO. The Coalition noted that there was no time limit prescribed between the occurrence of an Event of Default and the declaration by the TA that an Event of Default has occurred. If for example, an Event of Default occurred during the construction of the Facility, then under Section 13.4 as written, the TA could allow the GFO to complete construction, provide service for as long as it took the TA to find a replacement generator and then terminate the Agreement. The Coalition believed this was unfair.

The Coalition believed that the TA must make its election as regarding the occurrence of, and remedies for, any Event of Default within a reasonable period after it first becomes aware that such Event of Default has occurred. The Coalition proposed that such period be 30 days. Additionally, Section 13.4 provided that the TA may declare an amount equal to $5,000/MW of Accepted Credit Capacity payable as Liquidated Damages.

The Coalition believed that it should be clear in the Agreement that this was a one-time payment. It should not be open to the TA to not terminate the Agreement but continue to seek repeated Liquidated Damage amounts of $5,000/MW of Accepted Credit Capacity for continuing Events of Default.

The Coalition also stated that Calpine concurred with all the Coalition's comments.

2.3.2 Views of ENMAX

In its reply comments upon the February 12 filing of EAL, ENMAX stated that EAL and the parties had identified three issues during the course of settlement discussions that remained in dispute. ENMAX wished to provide comments on each of the items. In addition, ENMAX sought a clarification with respect to the condition precedent provisions of the negotiated settlement.

With respect to "maximum time to commercial operation" ENMAX supported EAL's most recent proposal, and submitted that it offered a reasonable arrangement.

ENMAX noted that certain interested parties proposed that the definition of "Forced Outage" be amended to allow for generator de-rates and that EAL opposed this. ENMAX supported EAL's proposal, namely that EAL would accept that a Dispatch Instruction was satisfied if the output of the Facility exceeded 90% of its Credit Capacity and submitted that this proposal was reasonable and provided adequate flexibility to account for de-rates.

ENMAX noted that EAL has proposed to increase the number of allowable Cure Periods during the term of the contract from two Cure Periods to six; to limit the maximum duration of all Cure Periods to 365 days, and to stipulate that the number of allowable Cure Periods during the term of the contract be applicable only after six months following Commercial Operation Date ("COD").

ENMAX claimed that certain parties have suggested that LBC SO generators be allowed to trigger Cure Periods within 24 months from the date of an Acceptance without such Cure Periods counting against the aggregate Cure Period limit of 365 days or the allowed number of Cure Periods. EAL opposed this, taking the position that this was unnecessary, and that its proposal provided sufficient flexibility.

ENMAX agreed that LBC SO generators ought to be allowed to trigger Cure Periods within 24 months from the date of an Acceptance without such period counting against the aggregate Cure Period limit of 365 days or the allowed number of Cure Periods. ENMAX argued that this proposal would incent EAL to ensure the earliest possible Acceptance date in order to ensure that the 24 month grace period begins to run as soon as possible. In turn, this would also ensure that generators have the maximum amount of time between the Acceptance date and the Required Commercial Operation Date ("RCOD").

ENMAX noted that Article 7.1(a)(iv) referred to a Generating Facility Owner ("GFO") obtaining EPA approval and HEEA Approval. EAL has indicated that it is prepared to expand this condition precedent to refer to a GFO obtaining EPA approval and HEEA Approval "or equivalent approvals." ENMAX submitted that this condition precedent should be expanded to include *all* required approvals, not just approvals which were equivalent to EPA and HEEA approvals. ENMAX claimed that there was no justification for limiting the condition precedent in the manner suggested by EAL.

In conclusion, ENMAX reiterated its concerns over the potential for voltage collapse in southern Alberta and urged the Board to approve the LBC SO as expeditiously as possible.

2.3.3 Views of FIRM

FIRM stated that they supported the changes proposed by EAL at Appendix A of EAL's February 12 refiling.

FIRM noted that two issues were discussed at the meeting of February 8 upon which agreement was not reached. With respect to the suggestion that that the definition of Forced Outage allow for generator de-rates FIRM noted that EAL did not support such a change because it would significantly increase the burden of administering the contract. Instead, EAL has proposed to accept that a Dispatch Instruction would be deemed to have been satisfied if the output of the Facility exceeds 90% of its Credit Capacity. This provision provided flexibility for de-rates and aligned dispatch requirements with the current Power Pool rules. FIRM supported EAL's position.

The second proposal arising from the meeting related to the increasingly tight time requirement to meet the RCOD. Some proposed that a generator should be allowed to trigger Cure Periods within 24 months from the date of an Acceptance without having them count against the aggregate Cure Period limit of 365 days. (The 24 months represented construction time.) FIRM noted that EAL considered this provision to be unnecessary, as there was already sufficient flexibility around Cure Periods (see Item 5 of Appendix A). FIRM stated that they had some sympathy for the generators' concern as the LBC SO process timetable had extended further than initially anticipated. With an LBC SO initiation in March this would be some 4 months short of 24 months for RCOD of December 2002. With the flexibility around Cure Periods allowing the generator to trigger within 22 months appeared to be an appropriate compromise in the circumstances. FIRM considered this period would provide the generator sufficient incentive to meet the target date and potentially allow more participants into the LBC SO process.

FIRM also commented upon the issue of Minimum Annual Hours, noting that in their comments of January 31 FIRM suggested a business case be provided to support the EAL proposed schedule of minimum annual payments over the 20 year contract period. In subsequent discussions with EAL it was FIRM's understanding that four scenarios would be provided in spreadsheet format to support the schedule proposed. FIRM noted that no such level of detail has been provided, just a brief narrative description. FIRM remained concerned that that a significant issue with respect to obligatory annual payments over 20 years did not have any supporting analysis on the record nor was there any review conducted by interested parties.

2.3.4 Views of TCE

In its reply comments, TCE stated that it strongly disagreed with EAL's comments with respect to section 4.1(f) and 5.1(b)(ii) for the reasons set out by TCE in its January 31, 2001 letter and for other obvious reasons.

TCE stated that Article 7.1(d) contains a typographical error in that it references "Section 7.1(a)(a".

TCE also stated that in Schedule 1, the definition of "Commercial Operation Date" should have the second sentence revised. This revision should read:

> Once the Facility has begun generating in order to fulfil its Commercial Operation Date, and until the Commercial Operation Date, the Facility must operate at the Tranche of Credit Capacity during all hours where the Pool Price is equal to or greater than the Operating Cost Benchmark (changes are underlined).

2.3.5 Views of Duke

Duke's comments were focused on Article 13.7 Limitation of Liability, section (a) Direct Loss or Damage which read:

> For the purposes of this Article, "Direct Loss or Damage" means, in relation to a Party, any and all liabilities, indebtedness, obligations, losses, damages, claims, assessments, fines, penalties, costs, fees and expenses of any kind, nature or description suffered or incurred by such Party, arising out of or in any way connected with a breach or default of this Agreement by the other Party…

Duke was concerned that this language, rather than adequately defining direct costs, included other costs that were indirect in nature. Duke took some comfort in EAL having liability protection through legislation but noted that the liability protection was subject to periodic review. Duke requested that should the existing liability protection afforded EAL as Transmission Administrator be nullified, Article 13.7 still be considered contractually as if the liability protection were in effect for the term of the LBC SO contract.

2.4.1 Comments from EAL on February 16, 2001

ESBI Alberta Ltd.
Location-Based Credits Standing Offer (LBC-SOLBC SO)
Response to Coalition Letter of February 13, 2001

Introduction

1. ESBI Alberta Ltd. (EAL) has reviewed the letter to the Alberta Energy and Utilities Board ("the Board"), dated February 13, 2001, entitled *Revised Filing of the Location Based Credit Standing Offer: Comments of the Coalition (concurred to by Calpine)*. EAL finds it necessary to respond to that letter. Based on comments contained in the Coalition's letter and in replies of other parties filed earlier it appears that the interested parties may have lost sight of the underlying purpose and objective of the LBC SO process. Accordingly, before dealing with the specific comments made by the Coalition, EAL would like to remind interested parties of three things.

2. First, as set out in AEUB Decision 2000-76, "The LBC SO is a process of providing incentives to generators to locate in certain areas of the province *in order to relieve transmission system constraints*" [emphasis added]. Therefore, the successful LBC SO generators will be constructing proxies for transmission. As such, the performance requirements for the LBC SO generation projects are different than those that would be associated with generation projects in general. A relaxation of the LBC SO performance requirements beyond those already negotiated between the Transmission Administrator and the Coalition, as suggested by the latter in its recent correspondence, will seriously erode the ability of the LBC SO project to fulfil its fundamental purpose.

3. Second, the supplemental payments are a very significant part of the LBC SO. Having successfully negotiated these payments in exchange for stringent dispatch requirements, the Coalition now seeks to significantly relax those dispatch requirements while maintaining the supplemental payments. This is unacceptable and must be rejected unless the supplemental payments are also reduced.

4. Third, the Coalition has raised a number of points in its letter that have already been dealt with through the Board's process and direct negotiations with the Transmission Administrator. To revisit these issues now is an abuse of the regulatory process. All

comments not directly related to the changes filed by the Transmission Administrator on February 12, 2001 should be summarily dismissed.

Comments of the Coalition

5. The Coalition takes issue with Subsection 3.1(c) of the contract. This section was filed with the Board as part of EAL's LBC SO application in September. It was debated during the hearing. It was approved by the Board in Decision 2000-76. It was not raised by the Coalition in written comments filed with Board on January 31, 2001. It was not mentioned by the Coalition in the meeting that EAL held with the Coalition, FIRM Customers, ENMAX, and others on February 8. These comments should be dismissed.

6. The Coalition requests that the Board ensure that the Transmission Administrator put in place a process that allows for prompt approval of lower-voltage connections. All such requests received at least one week before the Standing Offer implementation date will be reviewed and, if acceptable to the Transmission Administrator, will be granted. EAL cannot guarantee the evaluation of requests received less than one week before the implementation date.

7. The Coalition suggests that Section 3.1(e)(iv) of the contract be rewritten to indicate that the Transmission Administrator cannot "impose" an interconnection point on the GFO. This section, too, was filed with the Board as part of EAL's LBC SO application in September. It was debated during the hearing, was approved by the Board in Decision 2000-76, was not raised by the Coalition in written comments filed with Board on January 31, 2001, and was not mentioned in the February 8 meeting. These comments should be dismissed.

8. The Coalition recommends changing Section 3.1(g)(i) of the contract so that it imposes certain constraints on the Transmission Administrator's requirement that the Facility be compatible with the Model Validations and Audit System ("MVAS"). For the same reasons set out in ¶5 and ¶7, these comments should be dismissed.

9. The Coalition opposes EAL's proposed penalty of $500/MW per hour for missing the Maximum Time to Commercial Operation. This proposal was made in response to the Coalition's concern that contract termination was too severe a penalty for such a failure. In EAL's view, a GFO, acting prudently, will have no trouble meeting the already generous response times except in cases where the Facility is incapable of responding, which cases are already adequately covered by Forced Outage, Force Majeure, and Permitted Unavailability provisions.

10. As mentioned above, the Coalition offered to meet stringent dispatch requirements in exchange for valuable supplemental payments. EAL has agreed to impose a financial penalty for failure to meet generous dispatch response times instead of considering this to

be a breach of contract. The Coalition now seeks to further dilute this penalty to the point of insignificance.

11. That the GFOs are seeking to virtually eliminate performance risk (while continuing to receive supplemental payments) is obvious from their requests to:

- change "best efforts" to "reasonable commercial efforts" [§5(a)];
- reduce the penalty for failure to meet the Maximum Time to Commercial Operation to either $100/MW or $50/MW [§5(b)]. In EAL's view the penalty proposed by the Coalition is totally inadequate—they are a mere 10% and 5%, respectively, of the maximum amount the GFOs can receive from load customers for their output.
- round *down* to the nearest hour for timing purposes [§5(d)];
- pro-rate the penalties by the shortfall amount [§5(f)]. EAL notes that the delivery requirement has already been relaxed by granting that deliveries within 90% of contract capacity will be deemed to have met the dispatch request.
- replace the standard of Good Electric Operating Practice by one that simply requires that there be neither gross negligence nor wilful misconduct [§5(g)], even though the Board specifically approved Good Electric Operating Practice in Decision 2000-76.

EAL opposes all of these changes.

12. To simplify the performance penalty structure and to limit the GFOs' financial exposure, EAL proposes to leave the penalty at $500 per MW of Credit Capacity per hour for a maximum of 24 hours beyond the Maximum Time to Commercial Operation. Beyond the 24-hour period, the Transmission Administrator would have the option of terminating the contract.

13. The Coalition repeats its comment of January 31 that the definition of Approvals should be expanded to include, "…and all other orders, permits, approvals and consents required by Legislation in order to own, construct and operate the Facility as are identified in the Construction Schedule." The definition of Approvals is meant to deal with fundamental approvals. Expanding the definition would give rise to the real possibility that a GFO would have an option to exit the Agreement as a result of not receiving a non-material approval. This was the definition of Approvals accepted by the Board in relation to the IBOC Agreements. Accordingly, there is no reason to deviate from it.

14. The Coalition proposes a modification of audit periods [§7]. This issue was dealt with in Decision 2000-76, and the Coalition failed to note any concern in its January 31, 2001 submission. Their proposal should be dismissed.

15. The Coalition [§8] expresses concern over the Cure Period provisions. These provisions are intended to address catastrophic failures that would be expected to occur only once or twice in the commercial life of a generator. Given that an LBC SO generator must have a high level of reliability over the 20-year contract term in order to be a substitute for transmission, EAL believes that the Cure Period provisions are already generous. The Coalition's concern about early problems is amply addressed by starting to count the number of Cure Periods six months after the COD.

16. EAL understood that an agreement in principle was reached on this item in the February 8 meeting. The comments the Coalition has provided are not reflective of that agreement.

17. Finally, the Coalition claims there is a disincentive for the GFO to reach its COD before the RCOD. EAL disagrees. The GFO has ample financial incentive to meet an early COD under Section 4.1(f) of the contract, which provides twice the amount of the LBC Rate for an early COD.

18. Section 13.4 is the same "Termination for Event of Default" provision accepted by the Board in relation to the IBOC Agreements, and there is no reason to alter it.

APPENDIX 2

Location Based Credits Standing Offer
February 8, 2001

In response to intervenor comments, EAL proposes the following changes to the Location Based Credit Entitlement Offer:

1. **Maximum Time to Commercial Operation:**

a) Schedule 5 - The Maximum Time to Commercial Operation for a Combined Cycle Gas Turbine Plant to be changed from three hours to four hours to allow for ramp-up from cold-start.

b) Failure to meet the Maximum Time to Commercial Operation to be changed from termination of contract to a payment to the TA in the amount of $500/MW of Credit Capacity for each hour that the Generation Facility Owner (GFO) exceeds the Maximum Time to Commercial Operation. ~~The TA will retain the option of terminating the contract if the time required to have the Facility in Commercial Operation exceeds twice the Maximum Time to Commercial Operation. All of this to be subject to Permitted Unavailability and Forced Outage.~~ [As amended in the electronic mail message from the Transmission Administrator following the meeting]: In the event the GFO takes longer than twice the applicable Maximum Time to Commercial Operation, the amount payable will be doubled from that point forward (i.e., $1000/MW).

2. **Approvals** - Section 7.1(a)(iv), to be changed to include approvals that are equivalent to EPA Approval or HEEA Approval.

3. **Representations and Warranties** - The TA to make representations and warranties equivalent to those of the GFO in Sections 10.2(a), 10.2(b), and 10.2(c).

4. **Materiality:**

a) Event of Default under Sections 13.1(a) and 13.1(b) to be limited to material breach only.

b) Event of Default under Section 13.1(f), concerning a Recovery Plan, to be limited to non-compliance which will have a material adverse effect on the Recovery Plan.

5. **Event of Default Regarding Cure Period** - Section 13.1(g) to include an aggregate limit of 365 days for the duration of all Cure Periods during the term of the contract. This restriction to be offset by:

a) An increase in the number of allowable Cure Periods during the term of the contract from two Cure Periods to six; and

b) The number of allowable Cure Periods during the term of the contract to be applicable only after six months following COD.

6. **End of a Cure Period** - Section 13.2(f), concerning when a Cure Period ends, to include:

a) When the average Energy Ratio of the Facility is restored to 95% over any one-month period; or
b) When the Facility has completed testing similar to the requirements for achieving COD.

7. **Requirements to Achieve Commercial Operation Date** - The GFO to be allowed to shut-down the Facility during the testing period when pool price is below the Operating Cost Benchmark. During hours when the pool price is equal to or greater than the Operating Cost Benchmark, the Facility must operate at an average rate of 98% of the Tranche of Credit Capacity.