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ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

Addendum to Decision 2000-21 and
Review and Variance Decision
Dated August 26, 2002

INTRODUCTION

The Board issued *Decision 2000-21* on March 31, 2000, after conducting a public hearing initiated by Goodwell Petroleum Corporation Ltd. over the period November 29-30 and December 1-3 and 7-8, 1999, in Calgary, Alberta. As a result of *Decision 2000-21*, the Board ordered the shut-in of four wells licensed to Alberta Energy Company (AEC) for conservation and equity reasons, as more particularly set out in *Decision 2000-21*. The wells in question are

Well 00/01-13-082-22W4M/0 (Licence No. 0207155) Pad E4

Well 00/02-13-082-22W4M/0 (Licence No. 0207153) Pad E4

Well 02/11-18-082-21W4M/2 (Licence No. 0208034) Pad E5

Well 00/09-18-082-21W4M/0 (Licence No. 0208028) Pad E6

(hereinafter the "subject wells").

AEC applied to the Board on March 19, 2002, for a review and variance of *Decision 2000-21* regarding the shut-in of the four wells, and in a decision dated August 26, 2002, the Board denied the review and variance application.

AEC successfully sought leave to appeal both the main decision and the review and variance ruling, as these decisions related to the equity issue between Goodwell and AEC. Prior to the Court of Appeal's consideration of the matter, AEC had satisfied the EUB that the bitumen conservation concerns identified by the Board in *Decision 2000-21* had been addressed. On October 2, 2003, the Court of Appeal issued its decision1 upholding the AEC appeals. The Court of Appeal directed the Board to rescind the shut-in order regarding the four wells, referring the matter back to the Board for consideration and redetermination according to the Court of Appeal's direction.

DECISION

The Board has reviewed the Court of Appeal decision dated October 3, 2003, and hereby orders that the shut-in order respecting the subject wells be rescinded immediately, as more particularly outlined in the attached Order.

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[1] Alberta Energy Company Ltd. v. Goodwell Petroleum Corporation Ltd., 2003 ABCA 277.

Dated at Calgary, Alberta, on October 16, 2003.

ALBERTA ENERGY AND UTILITIES BOARD

J. D. Dilay, P.Eng.
Board Member

T. McGee
Board Member

R. J. Willard, P.Eng.
Acting Board Member

Order No. 1039128

ALBERTA ENERGY AND UTILITIES BOARD

IN THE MATTER OF THE *ALBERTA ENERGY AND UTILITIES BOARD ACT*, R.S.A. 2000, Chapter A-17; the *ENERGY RESOURCES CONSERVATION ACT*, R.S.A. 2000, Chapter E-10, as amended; the *OIL AND GAS CONSERVATION ACT*, R.S.A. 2000, Chapter 0-6 and regulations thereunder; and the *OIL SANDS CONSERVATION ACT*, R.S.A. 2000, O-6 and regulations thereunder

ORDER

Whereas the Alberta Energy and Utilities Board (EUB) issued *Decision 2000-21*, dated March 31, 2000, in which the EUB ordered the shut-in of four wells licensed to Alberta Energy Company (AEC) in the Britnell region of the Oil Sands Area;

And whereas the EUB denied AEC's application for a review and variance of *Decision 2000-21* on August 26, 2002;

And whereas AEC appealed the shut-in of the four wells, as well as the denial of its review and variance application;

And whereas the Alberta Court of Appeal issued its decision, being Action Numbers 00-18795-AC and 0201-0286-AC on October 2, 2003, upholding the appeal and directing the EUB to rescind its shut-in order of the four wells;

Therefore, it is hereby ordered that:

1. The EUB's shut-in order of the following wells is rescinded immediately:

   Well 00/01-13-082-22W4M/0 (Licence No. 0207155) Pad E4

   Well 00/02-13-082-22W4M/0 (Licence No. 0207153) Pad E4

   Well 02/11-18-082-21W4M/2 (Licence No. 0208034) Pad E5

   Well 00/09-18-082-21W4M/0 (Licence No. 0208028) Pad E6

2. AEC is permitted to resume production of bitumen, associated solution gas, and initial gas-cap gas incidental to bitumen recovery, provided it continues to follow modern operating practices and complies with relevant legislation.

Dated at Calgary, Alberta, on October 16, 2003.

ALBERTA ENERGY AND UTILITIES BOARD

J. D. Dilay, P.Eng.
Board Member

T. McGee
Board Member

R. J. Willard, P.Eng.
Acting Board Member

ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

GOODWELL PETROLEUM CORPORATION LTD.
REQUEST TO SHUT IN BITUMEN WELLS
WABISKAW-MCMURRAY OIL SANDS DEPOSIT **Decision 2000-21**
ATHABASCA AREA – BRINTNELL SECTOR **Application No. 1039128**

1 DECISION

The Board will order that the following wells be shut in effective April 7, 2000:

- Well 00/01-13-082-22W4M/0 (Licence No. 0207155) and 00/02-13-082-22W4M/0 (Licence No. 0207153), Pad E4
- Well 02/11-18-082-21W4M/2 (Licence No. 0208034), Pad E5
- Well 00/09-18-082-21W4M/0 (Licence No. 0208028), Pad E6

Shut-in of the above wells will continue until AEC East has obtained the full rights to produce and the impact of producing significant gas-cap gas, which occurs disproportionately in a few wells, on bitumen recovery is addressed and depletion plans are approved in accordance with *Interim Directive (ID) 99-1: Gas/Bitumen Production in Oil Sands Areas, Application, Notification, and Drilling Requirements.* In this regard, the parties are encouraged to renew negotiations, taking into account the Board decision on reserves and focusing on gas-cap production from four wells for cost-sharing consideration.

In addition to the foregoing, the Board directs AEC East as follows:

- Representative stabilized pressure surveys must be taken and incorporated in an EOR feasibility study that must be filed by December 31, 2000. No production testing of the shut-in wells is permitted unless authorized by the EUB.
- Pressure survey information for the wells 02-13, 15-25, 01-36, 11-18, 2/11-18, and 09-18 must be filed in accordance with EUB *Guide 40: Pressure and Deliverability Testing Oil and Gas Wells* by May 1, 2000.
- Effective May 1, 2000, Class-I gas measurement is required for the area of application: wells on Pads E3, E4, E5, and E6 (see Appendix 1).

The Board will invite Alberta Department of Resource Development (DRD), Canadian Association of Petroleum Producers (CAPP), and Small Explorers and Producers Association of Canada (SEPAC) to participate in a review of the regulatory needs, documentation of requirements, and operating practices appropriate for the wider range of producing situations becoming evident for declared bitumen[1]-producing wells.

2 INTRODUCTION

2.1 Application

Goodwell Petroleum Corporation Ltd. (Goodwell) applied to the Alberta Energy and Utilities Board (EUB/Board) for the immediate shut-in of 16 horizontal bitumen wells owned by AEC East on the grounds that the wells are producing significant volumes of original gas-cap gas that AEC East does not have the right to produce. The wells are located in Sections 18, 19, and 30 of Township 82, Range 21, West of the 4th Meridian, and Sections 24 and 25 of Township 82, Range 22, West of the 4th Meridian (subject lands).

Goodwell also questioned whether the production of significant volumes of gas-cap gas is detrimental to bitumen recovery.

The wells producing from four pads (E3, E4, E5, and E6) are listed in Appendix 1 and are referred to collectively in the report as the subject wells. Other well locations outside of the subject lands and referred to in the report are listed in Appendix 2.

Goodwell sought the shut-in of AEC East's wells until

- an agreement is entered into between Goodwell and AEC East for production sharing, or
- AEC East can operate the wells without producing gas-cap gas in significant quantities, or
- AEC East can begin a program to reinject whatever gas-cap gas it produces from the subject wells back into the reservoir, and
- can produce the reservoir as a whole in a manner not wasteful of either the bitumen or the gas-cap gas.

2.2 Hearing

The application was considered at a public hearing on November 29-30 and December 1-3 and 7-8, 1999, in Calgary, Alberta, with Board Members J. D. Dilay, P.Eng., T. McGee, and Acting Board Member R. J.Willard, P. Eng., sitting.

The following table lists those who appeared at the hearing and the abbreviations used in this report.

[1] As per Part 1(2)(d) and (e) of the Oil Sands Conservation Regulations.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Goodwell Petroleum Corporation Ltd. (Goodwell) S. M. Shawa	P. Brown, P.Geoph. P. N. Byers, P.Geol., Ph.D.
AEC East, a business unit of AEC Oil and Gas Partnership (Partners: Alberta Energy Company Ltd. and AEC West Ltd.) and Amber Energy Incorporated (Amber) (collectively referred to as AEC East) R. M. Perrin	D. Swyston, P.Eng. I. Langdon, P.Eng. F. Madadi, P.Geol. J. Johnston, P.Eng. R. Strobl, P.Geol. R. Baker, P.Eng
Renaissance Energy Ltd. (Renaissance) L. M. Sali D. Lawrence, P.Eng.	
Anderson Exploration Ltd. (Anderson) K. Krynowsky, P.Eng.	
Canadian Natural Resources Ltd. (CNRL) L. Olthafer	
Gulf Canada Resources Ltd. (Gulf) B. Lounds, P.Eng. D. Thomas	
PanCanadian Petroleum Ltd. (PanCanadian) P. Kahler	
Alberta Energy and Utilities Board staff N. Barnes D. Larder R. Parkyn A. Wiechert, P.Geol	

2.3 Interventions

Interventions opposing the application were filed by AEC East, Anderson, CNRL, Gulf, and PanCanadian.

Renaissance intervened in support of the Goodwell application. All interveners have an interest in the production of bitumen and/or its associated gas-cap gas in the area of application or in the general area. With the exception of AEC East, all other interveners participated in the hearing for purposes of cross-examination and argument only.

2.4 Background

Goodwell holds the petroleum and natural gas (P&NG) rights for gas only to five contiguous sections, namely, Sections 18, 19, and 30-82-21W4M and Sections 24 and 25-82-22W4M (see figure attached), in the same geologic zone in which Amber holds the bitumen rights. Amber drilled and operated 16 horizontal wells until October 23, 1998, when AEC East purchased Amber. Currently the wells are producing between 5 and 15 cubic metres per day (m^3/d) of 17º API bitumen with gas-oil ratios (GORs) ranging from 120 to 1300 m^3/m^3.

Goodwell submitted that AEC East had been producing large volumes of the initial gas-cap gas concurrently with bitumen since production commenced in November 1997 and was continuing to do so. As a result, Goodwell requested that the subject wells be shut in until AEC East obtained the full right to produce.

Goodwell stated that because AEC East did not measure and publicly report gas production for the first six months, Goodwell was unaware of the extent of the gas volumes produced with the bitumen. Once alerted by the public record and approached by Amber, Goodwell participated in discussions about a sharing agreement with Amber and subsequently with AEC East, but without resolution. With production ongoing and with the initiation of gas conservation and gas sales in September 1998, from which Goodwell did not receive a share of revenue, Goodwell applied to the EUB to order the shut-in of the subject wells in order to protect its rights and to address the appropriateness and fairness of future operations.

Goodwell also initiated civil court proceedings for compensation of past production. Goodwell believed that significant volumes of its initial gas cap reserve has been removed, lost, or sold without compensation from AEC East. Goodwell has not drilled a well on the subject lands; however, Goodwell believed it could not develop its gas property because of both the extent of gas depletion and the likelihood of AEC East objecting to a gas well producing. Goodwell reported that it would be willing to assume a reasonable share of the gas conservation costs associated with the production and the cost of drilling one or two wells.

AEC East shut in several high-GOR bitumen wells when Goodwell first expressed concerns but subsequently returned the wells to production when tests showed their GOR dropped following a three- to four-month suspension. AEC East believed that the initial gas caps were very small, gas cap production was incidental to its bitumen production, and revenue sharing should require Goodwell to assume a share of all bitumen and gas conservation development costs, rendering gas-cap gas noncommercial.

Goodwell reported that failed negotiations resulted from disagreements over gas-cap reserve estimates and the determination of the capital and operating costs to be used in sharing agreements. AEC East agreed that these were major points of disagreements, but it also held different views as to mineral ownership and its rights as a bitumen mineral lease owner (the need or appropriateness to negotiate if GORs are under 1800 m^3/m^3).[2] It also questioned the extent of EUB jurisdiction in these matters. Both AEC East and CNRL believed that the more complete and appropriate remedy to Goodwell was through the courts.

The parties discussed third-party arbitration but did not pursue it due to the difference in positions.

3 ISSUES

The Board considers the issues respecting the application to be

- authority of the EUB
- technical issues
- need for the shut in of the subject wells
- other matters

4 AUTHORITY OF THE EUB

4.1 Views of the Applicant

Goodwell sought to have the subject wells (listed in Appendix 1, with abbreviations) shut in on the basis that AEC East was producing gas-cap gas that Goodwell, not AEC East, had the right to recover. Goodwell also expressed a conservation concern for shutting in the wells, namely, that the rapid depletion of the initial gas cap would adversely affect the amount of bitumen eventually recovered. It argued that the EUB has sufficient authority to shut in the wells under the specific suspension authority set forth in Sections 19 and 33 of the Oil and Gas Conservation Act and Section 9 of the Oil Sands Conservation Act. Goodwell also submitted that general authority-granting provisions in Section 7 of the Oil and Gas Conservation Act and Sections 5 and 6 of the Oil Sands Conservation Act combined with the express purposes of the two statutes empower the EUB to shut in the subject wells.

4.2 Views of the Interveners

AEC East, supported by CNRL, submitted that the specific suspension provisions may not be invoked, as AEC East has not contravened any statute, regulation, or EUB order, nor has it engaged in any operations that could be described as hazardous, inadequate, or defective. It maintained that it is presently in full compliance with all EUB requirements and operates the wells based on good production practices (GPP). It stated that there were no bitumen conservation concerns caused by the current volumes of gas being produced. AEC East commented that even though it did not have the right to recover the gas-cap gas, it was entitled to produce that quantity of gas-cap gas required to exploit its bitumen resource without consideration for the gas mineral lease owner and provided that it was utilizing GPP and reasonable, proper, and accepted industry extraction techniques.

[2] As per Section 90(2) of the Mines and Minerals Act of Alberta Department of Resource Development.

AEC East submitted that the initial gas caps were small, isolated pockets not economic to recover. Consequently, AEC East did not believe that it was negatively affecting Goodwell's opportunities to recover its gas.

Renaissance endorsed the need for the rights of both P&NG and bitumen owners to be respected and the need for compliance with appropriate regulations.

4.3 Views of the Board

The Board does not accept AEC's and CNRL's submission that its authority to shut in the subject wells is constrained in the circumstances of the present application. The Board's power regarding conservation and the orderly and efficient development of energy resources, for example, is both general and specific, as expressed in the provisions of its enabling legislation. Section 2(c) of the Energy Resources Conservation Act (ERC Act), Section 4(a) and (c) of the Oil and Gas Conservation Act (OGC Act), and Section 3(a) and (b) of the Oil Sands Conservation Act (OSC Act) identify these objects as a fundamental responsibility of the Board. Provisions such as Sections 15 and 21 of the ERC Act, Sections 7 and 86 of the OGC Act, and Sections 5 and 6 of the OSC Act grant to the Board the general authority to shut in wells for conservation reasons.

Further, there is specific authority for the Board to direct that wells be shut in under the circumstances of the present application. Section 21(1)(u) of the Oil Sands Conservation Act allows the Board to make regulations "generally to conserve oil sands and crude bitumen and to prevent the waste or improvident disposition of oil sands…." Alberta Regulation 48/99 provides in Section 3(5):

> Where it appears to the Board that the ultimate recovery of crude bitumen in the oil sands strata may be affected by gas production, the Board may, on it own initiative or on the application by an affected party, make any order or directive it considers necessary to effect the conservation of the crude bitumen in any particular case.

This regulation invests the Board with the requisite authority to shut in the subject bitumen wells if it is satisfied that the associated gas production will adversely affect the ultimate recovery of the crude bitumen. This authority supports *ID 99-1*, issued by the EUB to address many of the gas-over-bitumen issues. Specifically, applications are required and EUB approval must be received for all new situations of gas-over-bitumen production and in all pre-1999 cases where there are complaints. The requirement to address gas-over-bitumen production does not distinguish between gas wells or bitumen wells producing gas-cap gas. *ID 99-1* also addresses the need to drill enough representative vertical wells to confirm geological description.

The Board notes that the subject area of this application does not have EUB approval for gas-cap production.

Where conservation and equity issues are not shown to be properly addressed, the EUB may deny or condition gas-cap production resulting in shut-in or production constraints. In this regard, the EUB does not use any prescribed GOR marker, such as 1800 m^3/m^3, as proposed by

AEC East, to govern whether gas-over-bitumen production is a conservation issue or to distinguish between mineral ownership.

The jurisdiction to shut in or suspend the AEC East wells on the basis that they are producing significant volumes of gas-cap gas that are the subject of the Goodwell P&NG leases is also available to the EUB. Section 10 of the Oil Sands Conservation Act requires companies to obtain prior approval from the EUB before operations to recover oil sands or crude bitumen may be commenced. This is underscored by Section 3(1) of the Oil Sands Conservation Regulation. The regulation provides that an applicant must apply for a licence and adopts Parts 2 and 13 of the Oil and Gas Conservation Regulations with respect to the licensing process. Under Part 2, an applicant must submit an application in conformity with EUB *Guide 56: Energy Development Application Guide and Schedules* and provide the information prescribed by the appropriate application form. One essential piece of information is confirmation that the applicant has the right to recover the hydrocarbon, which is the subject matter of this application. The EUB's issuance of a licence represents EUB approval to drill and produce that identified hydrocarbon.

Regarding the present application, the EUB had issued a licence to AEC East to drill and produce crude bitumen. If AEC East is in fact producing gas-cap gas, then it is in breach of its licence and the licence may be suspended pursuant to Section 13(2) of the Oil and Gas Conservation Act. This section provides:

> If it is proved to the satisfaction of the Board that a licensee was not entitled, or was not the authorized representative of the person who was entitled, to the right to produce the oil, gas or crude bitumen at the time the licence was granted, the licence is void for all purposes except as to the liability of the holder of the licence to complete or abandon the well or to suspend operations as the Board prescribes.

It is also the Board's view that AEC East's production of gas-cap gas in the present case, if such finding is determined by the Board, invokes Sections 9 and 20 of the Oil Sands Conservation Act. These sections empower the Board to shut in or suspend bitumen wells in circumstances where operations have not been in accordance with the approval issued. For example, Section 20 states:

> If, in the opinion of the Board, an operation at an oil sands site or a suspension or abandonment of any scheme or operation is not in accordance with the terms or conditions prescribed under this Act or the regulations or in an approval issued under this Act, the Board or any person authorized by it may enter on the oil sands site and do whatever the Board considers necessary to assure that the operation, suspension or abandonment complies with the conditions prescribed in the approval.

In summary, the Board possesses the necessary power to shut in the wells for the purpose of the conservation of the bitumen and in circumstances where an operator is producing oil, gas, or crude bitumen in contravention of its licence.

5 TECHNICAL ISSUES

Examination of the issues requires a review of production and geology matters with a goal of identifying initial and remaining gas-cap reserves and categorizing well-producing characteristics.

5.1 Gas Production Estimates — Unreported Initial Gas Production

5.1.1 Views of the Applicant

Goodwell submitted that between December 1997, when production commenced from the subject lands, and June 1998 gas produced from the subject wells was not measured or reported. Goodwell estimated that the volume of unreported gas production over this period was 28.188 million cubic metres (10^6 m^3). It made this estimate by extrapolating back the composite GOR trend for all 16 wells to the initial production date. Goodwell stated that the GOR value at the midpoint of this back extrapolation was 600 m^3/m^3. This GOR represented the average amount of gas produced for each cubic metre of bitumen produced. Goodwell said that this method was reasonable and represented a conservative estimate of the total volume of unreported gas production.

Goodwell stated that it chose not to re-estimate its extrapolation using AEC East's additional GOR test data in its application because AEC East admitted that these limited data were incorrect, since gas measurement equipment was reportedly inadequate to handle the high gas flow rates occurring at that time. In addition, Goodwell stated that it was reluctant to use AEC East's modified GOR data since AEC East's methodology was unclear.

5.1.2 Views of the Interveners

AEC East acknowledged that it did not measure and report gas production volumes during the first seven months of production from the subject wells but emphasized that this was in compliance with EUB approval. AEC East had applied and received Class-II measurement approval to relax measurement requirements in accordance with *ID 91-3: Heavy Oil/Oil Sands Operations*.

AEC East estimated the unreported gas volume using three different methods. AEC East suggested that there was a need to explore a range of methods given the known inaccuracies in estimating the producing GOR for the subject wells. One method took the average of all the individual well GOR tests measured during the unreported production period multiplied by each well's produced bitumen volume. This method resulted in an estimated volume of 20.0 10^6 m^3, which it believed substantially overstated the actual gas production volume. The second method substituted GOR data modified to better reflect the observed conserved metered gas volumes as well as the GOR test data. AEC East argued that this method yielded an estimated initial unmeasured gas production volume of 7.6 10^6 m^3, which it viewed as the minimum volume. AEC East referred to its final method as a cumulative method and submitted that it was the most reasonable way to estimate the unreported gas production. On the basis of a cumulative gas-versus-bitumen-production plot, AEC East extrapolated back the early measured GOR trends for each well to determine the total gas produced. It determined the unreported gas production using this method to be 11.99 10^6 m^3.

Renaissance did not submit any estimate of unreported gas production but questioned AEC East on its estimate for the 9-18 well. It argued that using AEC East's method of back-extrapolating the 9-18 GORs should have predicted over 25 per cent more gas production for that well than AEC East tabled in its evidence. AEC East did not disagree with Renaissance's interpretation of gas production for the 9-18 well.

5.1.3 Views of the Board

The Board is concerned about the adequacy of its regulatory process to deal with an otherwise routine measurement application intended to promote an appropriate and practical level of measurement accuracy. Clearly, in this case, the bitumen wells exhibited producing characteristics not expected of typical bitumen wells. The lack of data regarding millions of cubic metres of initial gas production is a significant hindrance in properly assessing conservation, environmental, and equity impacts.

The Board notes that AEC East supported its application for Class-II measurement based on the performance of the first few wells and the expectation of extremely-low GOR behaviour. The EUB did not condition the approval with a review clause should GORs vary significantly from application predictions. AEC East did not subsequently bring the changed circumstances to the EUB's attention, and EUB surveillance did not identify this case. Under Class-II measurement, GORs need to be tested within the first six months of production and annually thereafter. Such approval is common for many extremely low-GOR, high-viscosity bitumen wells. EUB regulations on measurement are addressed in more detail in Section 7.

The Board has reviewed Goodwell's and AEC East's different methods to estimate unmeasured gas volumes. The Board believes that AEC East's extrapolating back of the individual well GOR production trends is a valid procedure in the circumstances to estimate the unreported gas production volume. Goodwell's use of the composite GOR production trend, rather than the individual well GOR trend, fails to recognize different commencement of production dates for the pads/wells. Only Pad E3, with 4 of the 16 wells, produced over the majority of the initial time period. These wells account for approximately 60 per cent of the bitumen production in this period, and subsequent measurements suggest that they have the lowest GORs. As a result, the Board believes that Goodwell has overestimated unreported gas production.

As discussed in the next section, the Board has not received sufficient evidence to alter the reported measured volumes, and consequently has used only the public record data.

Extrapolating back the individual well GORs, as entered in the public record, the Board estimates an unreported gas volume of 11.0 10^6 m^3, similar to that estimated by AEC East. A comparison of Goodwell, AEC East, and EUB estimates are found in Appendix 3.

All total gas production volumes quoted subsequently in this report include their respective estimates of unreported gas production.

5.2 Reported Gas Production Volumes

5.2.1 Views of the Applicant

Goodwell adopted the reported gas production volumes and did not comment on the appropriateness of changes other than to express concern about the clarity of AEC East's methodology. Goodwell's gas production volume to March 1, 1999, was 46.9 10^6 m^3.

5.2.2 Views of the Interveners

AEC East said that individual well monthly testing of gas production commenced in June 1998. Once gas conservation began in September 1998, AEC East was able to conduct continuous measurement of produced volumes. AEC East submitted that GOR test data reported to the EUB did not include all of the available data on the subject wells. AEC East provided an unmodified total gas production volume estimate of 38.7 10^6 m^3 to March 1, 1999, which incorporated all available GOR test data.

With the implementation of gas conservation, AEC East found that use of the GOR test data resulted in a substantial overstatement of gas volumes when compared to conserved gas volumes. As a result, AEC East modified its gas production volumes to reflect both GOR test data and conserved gas volumes. It estimated that the total modified gas production volume to March 1, 1999, was 26.30 10^6 m^3.

AEC East also used the cumulative method to estimate gas production from the subject area. This method gave a total gas production volume to March 1, 1999 of 30.72 10^6 m^3. AEC East seemed to rely on this volume. In contrast, AEC East testified that it should, and probably will in the future, rely solely on the daily conserved gas volumes to determine gas production from the subject wells. Using the conserved gas volume, AEC East estimated total gas production from commencement of production to the end of April 1999 to be 24.5 10^6 m^3.

5.2.3 Views of the Board

The Board is concerned with AEC East's ongoing adjustments to the gas production volumes, given the importance of equity issues arising due to split bitumen and P&NG rights and the conservation question of accelerated gas-cap production. The Board also notes that the gas production data available on the public database are not consistent with any of AEC East's estimates.

The Board finds that insufficient evidence was presented in the hearing to justify adopting a significant change in data or even the directional change in gas volumes. AEC East may file a detailed measurement submission with the EUB's Operations Group concerning the most accurate and reasonable way to measure volumes in the future. However, in the absence of solid evidence, the Board will not make any corrections to the public record.

Using the Board's estimate of unmeasured initial gas volumes and the public production records, the Board finds that 29.7 10^6 m^3 of gas has been produced to March 1, 1999, a common reference point for the submissions. Additional gas production volumes to date will be added to each number when the EUB reviews the current circumstances.

5.3 Volumetric Original Bitumen-in-Place and Original Gas in-Place Estimates

5.3.1 Views of the Applicant

Goodwell based its estimate of initial gas-cap gas in place on a volumetric determination from its structure mapping of the Wabiskaw sands over the subject lands. Goodwell relied on a gas/bitumen interface identified in the 14-17 well at +217.9 m above sea level (asl) to extrapolate the gas-cap area over its lands using its structure map.

Goodwell asserted that differential compaction provided a mechanism for trapping gas over a Paleozoic high located on its lands. It presented a barrier island depositional model that it believed was consistent with its observations of the Wabiskaw zone in the Brintnell area. Goodwell interpreted that a barrier island system moved through the area during Wabiskaw time and resulted in the deposition of the reservoir-quality Wabiskaw sands. It noted that barrier islands systems have associated features, such as shoreface beach deposits, tidal channels, tidal deltas, tidal flats, and lagoons. Goodwell explained that while there are a number of informal members in the Wabiskaw, the Wabiskaw A sandstone is the only reservoir in the area.

Goodwell's structure map on the top of the Wabiskaw incorporated data from the vertical and horizontal well log control both on and offsetting its lands. When interpreting picks on the top of the Wabiskaw sandstone in the horizontal wells, Goodwell relied on the first penetration of the sand. It subsequently picked a Wabiskaw top only if the drill bit exited the top of the sand at breakout and a lithology change from sand to shale was noted on the horizontal well strip log. To add further control to its map, Goodwell used the elevation of the bit, as determined off the horizontal well strip logs, where the bit was still in the sandstone. This provided a minimum known depth for the Wabiskaw in those areas.

Goodwell's structure map indicated that the top of the Wabiskaw dropped off to the west, south, east, and northeast of the lands in question, creating a structural trap. The structure on the top of the Wabiskaw sandstone continued to climb from south to north. Goodwell noted that the 13-30 well (the only vertical well on Goodwell lands) and the 4-31 well were among the structurally highest wells in the area and did not have any evidence of gas or a gas cap in them. The applicant concluded that there must be a restriction preventing the migration of gas updip. Goodwell believed that the horizontal well log data interpreted within the framework of a barrier island system pointed to a shale-filled channel traversing the northwest quarter of Section 24-82-22W4M, the southeast quarter of Section 25-82-22W4M, and the southwest quarter of Section 30-82-21W4M. Such a shale filled channel would provide a stratigraphic trap, preventing the northward migration of gas. Goodwell pointed out that other operators in the area interpreted shale-filled channels in the Wabiskaw interval.

Goodwell stated that the 14-17 well was a critical well to its gas-cap interpretation. The 14-17 well has a gas/bitumen contact at +217.9 m asl. In addition, Goodwell relied on notation from the horizontal well strip logs for the 1-35 and the 1-14 wells to project the gas cap across Goodwell lands. The 1-35 well log header indicated that the driller encountered a gas cap at +218 m asl, within 10 centimetres (cm) of the interface at the 14-17 well. The well log header for the 1-14 well had a notation stating that a gas interval of <0.5 m was encountered at the top of the sand, structurally consistent with the 14-17 well. As further proof of the extent of the free gas cap, Goodwell also relied on the descriptions of gas-cut mud or gas bubbles in the mud in other horizontal well logs. It acknowledged that the horizontal well logs could not independently verify the existence of a gas/bitumen contact in the vicinity of the 1-35 and 1-14 wells. It believed that even if the notations had been absent, the gas/bitumen contact in the 14-17 well would have led it to make the same structural projection across its lands enclosing all elevations above +217.9 m asl as one continuous gas cap.

Goodwell compared pad GOR behaviour to structural position and believed that there was a relationship. In its opinion, wells in Pads E1 and E2, west of the subject lands and off structure, demonstrated non-gas-cap gas GOR behaviour. In contrast, Goodwell believed that the wells associated with Pads E3, E4, E5, and E6 on the subject lands and Section 13-82-22W4M and on structure demonstrated gas-cap gas GOR behaviour.

Goodwell acknowledged that its own analysis of the top of the Wabiskaw allowed latitude for interpretations that could incorporate sufficient structural low features to allow for a discontinuous gas cap over the Goodwell lands. This was not its preferred interpretation.

To calculate the volumetric estimate of the original gas in place over its lands, Goodwell used an average porosity of 29.9 per cent for the Wabiskaw sandstone, as determined from core analysis from the 14-17 and 15-7 wells. Goodwell assumed an 80 per cent gas saturation in the reservoir and was of the opinion that the residual oil saturation in the gas cap would be approximately 10 per cent, leaving a water saturation of approximately 10 per cent. The applicant acknowledged that it had not calculated a water saturation for the gas cap or reviewed pools for an appropriate analog, but had relied on EUB data for gas saturations in the Doucette and Smith Fields. Goodwell assumed a recovery factor of 85 per cent.

To calculate the original bitumen in place, Goodwell planimetered the area of its lands under the gas cap (approximately two sections in area) and assumed an average thickness of 4.5 m of bitumen for the remaining three sections of subject lands. Similarly, it used 29.9 per cent porosity and assumed a 62 per cent bitumen saturation based on EUB averages for Wabiskaw deposits, and a formation volume factor of 1.008. Appendix 4 shows a comparative list of reservoir parameters.

Using the noted parameters and its geological maps, Goodwell calculated the recoverable gas in place over its lands as 64.93 10^6 m^3. With a recovery factor of 85 per cent, the original gas in place over the subject lands would be 76.4 10^6 m^3. This calculation did not include any possible gas cap attributable to the 15-7 well on the south portion of Section 18-82-21W4M. Goodwell calculated the recoverable gas in place for the entire gas cap associated with the subject lands to be 107.2 10^6 m^3. With a recovery factor of 85 per cent, the original gas in place for the entire gas cap would be 126.1 10^6 m^3. Goodwell noted that its portion of the total gas cap as mapped over its lands was 60.6 per cent. Goodwell calculated the original bitumen in place under its lands to be 8.11 10^6 m^3. Goodwell believed that a recovery factor of 10 per cent was reasonable, resulting in recoverable reserves of 0.811 10^6 m^3. Appendix 3 gives a comparative list of reserve estimates.

Goodwell criticized AEC East's gamma ray methodology for determining the top of the Wabiskaw sandstone and its contouring methodology when developing its structure maps. Goodwell noted that AEC East used vertical and horizontal well control data by picking the top of the Wabiskaw sandstone when it was first encountered in both instances. AEC East made a pick for the Wabiskaw top every 50 m thereafter in the horizontal portion of each horizontal well. However, Goodwell argued that AEC East picked the sandstone top at drill-bit breakout points in both the top and bottom of the sandstone. Further, it noted that AEC East did not use a lithology change criterion to ensure that the top picked was the top of the sandstone and not simply a slightly shalier portion of the reservoir. In addition, Goodwell expressed concern regarding the validity of a methodology that allowed AEC East to continue to pick a Wabiskaw top regardless of whether the bit was in the sandstone or not simply by estimating where the top of the sandstone was relative to the gamma ray tool API reading. Goodwell also noted that, since AEC East targeted the best-quality reservoir near the top of the sand, it increased the potential of encountering gas reserves in the horizontal wellbores.

Goodwell argued that AEC East appeared to be driven in its selection of tops by a desire to show a map with isolated gas caps. Goodwell noted that the data in the vicinity of the 14-17 well as picked by AEC East did not appear to be supported by the well logs but allowed AEC East's computer contouring package to generate an isolated gas cap. Goodwell further criticized AEC East's selection of grid size for the computer-generated structure maps, which it said resulted in artificially detailed mapping that was a function of the selected mapping parameters and not proof of small, isolated gas caps in the area.

5.3.2 Views of the Interveners

AEC East acknowledged that the top of the Wabiskaw over Goodwell lands was generally structurally higher than in the surrounding area. However, it believed that the evidence pointed to very small structural closures that trap minor amounts of gas-cap gas. AEC East argued that without a vertical well to provide direct evidence of a gas cap and its areal extent, there was little proof of a large gas cap.

AEC East submitted that a commonly accepted interpretation of the Wabiskaw depositional environment for the area is a lower to middle shoreface environment, contrary to Goodwell's marine beach or upper shoreface deposition. AEC East stated that lower to middle shoreface depositional environment resulted in an extensive blanketlike sand body deposited at some distance from an east-west trending marine shoreline. AEC East reviewed cored wells in the area and noted that they revealed trace fossil assemblages that confirmed its interpretation of the Wabiskaw depositional environment as lower to middle shoreface, which was indicative of water depths greater than 2 m (usually between 5 m and 10 m) and anywhere from tens of kilometres to 100 km offshore. AEC East observed the thickness of the Wabiskaw A sandstone to be 4 m on average. Sand thickness near the shore or beach environment would be expected to be in the order of 12 m.

AEC East stated that structurally the Wabiskaw attempts to mimic the Paleozoic surface, confirming that the differential compaction process exerts influence, but noted that a structural complexity was superimposed on the Wabiskaw. Initially, AEC East stated that salt solution collapse in Devonian age rocks resulted in numerous sinkholes, which in turn led to small, high closures, which may or may not have gas. AEC East modified its interpretation of the controlling mechanism for the creation of small, high closures from salt solution collapse to karst[3]-related collapse features. AEC East noted that the karsting mechanism was more consistent with the scale of the collapse features that it interpreted from the horizontal well data in the area.

AEC East relied on a gamma ray methodology to create the structure maps on the top of the Wabiskaw sandstone. AEC East believed that the Wabiskaw gamma ray signature was unique in the area. It used this characteristic to estimate the location of the drill bit relative to the top of the Wabiskaw sandstone. It then used these Wabiskaw top picks in its structure mapping. AEC East recalibrated the gamma ray from the build portion of each horizontal well to the nearest offset well in the area. The recalibration resulted in a gamma ray factor that was used throughout the whole well. AEC East stated that when drilling a horizontal leg in the Wabiskaw, it attempted to maintain the bit within the sweet spot of the zone, approximately 0.7 to 1.0 m from the top of the sand. The sweet spot ranged from 1.0 to 1.5 m in thickness.

AEC East stated that it used all the available vertical well log data and the initial penetration of the Wabiskaw in the horizontal wells to construct its structure maps. It also picked the top of the Wabiskaw from data points along the trajectory of the horizontal leg at 50 m intervals, using its gamma ray methodology to estimate the location of the top. AEC East noted that it also incorporated data from drill bit breakouts through both the top and the bottom of the sand. It also stated that if it did drill through shale, it had a good idea of where the bit was in the Wabiskaw section because of the characteristic gamma ray signature. AEC East contoured its structure maps using a computer-contouring package. It argued that it created superior maps, as they were nonsubjective and utilized all Wabiskaw data points. AEC East presented three detailed structure maps over the lands in question and, while it admitted that there were some discrepancies among them, in general they showed that the top of the Wabiskaw sandstone structurally dropped off to the west, south, east, and northeast. It noted that the 13-30 and the 4-31 wells to the north demonstrated that there was no overall closure of the feature, as neither well had any evidence of a gas cap. AEC East pointed out that although its structure maps and Goodwell's structure map had similarities, the main difference between the interpretations was that AEC East's maps had an open-ended feature to the north with no trapping mechanism evident.

AEC East noted that its maps showed an abundance of small, isolated collapse features and numerous isolated structural highs. AEC East attempted to tie the high-GOR producing wells to the small, isolated structural closures to account for the high-GOR production. AEC East did not assign any gas pay to wells in areas with isolated highs and no indication of gas, such as the 13-

[3] Karst—A type of topography that is formed over limestone, dolomite, or gypsum by dissolving or solution, and that is characterized by closed depressions or sinkholes, caves, and underground drainage.

30 and 4-31 wells. In addition, the gas-filled structural closure was limited to 2 m, since AEC had not observed any wells in the area with greater than 2 m of gas pay. AEC East did not agree that all of the small structural highs it produced on its structure map were gas bearing.

AEC East agreed that the 14-17 well had a gas/bitumen contact at +217.9 m asl. AEC East argued that it was not appropriate to extrapolate this contact across the Goodwell lands. As evidence, AEC East cited the 4-1 and the 10-1 wells, with gas/bitumen contacts at +215.2 and +212.8 m asl respectively, as wells with differing interfaces approximately 0.805 km apart. AEC East compared the 15-7 well gas/bitumen interface at +215.4 m asl to the +217.9 m asl interface for the 14-17 well. It estimated that the 15-7 and 14-17 wells were 2.4 km apart. AEC East also noted that the wells offsetting the 15-7, 10-13, and 14-5 wells had similar structural positions but neither of these wells had a gas/bitumen contact. It confirmed that the data available for the 10-13 well provided an ambiguous gas/bitumen contact interpretation. AEC East emphasized that none of the wells updip of the 14-17 well had a gas-over-bitumen contact. It was obvious to AEC East that the variation in gas/bitumen contacts in the immediate area demonstrated localized structuring.

In areas where there was very little structural change, AEC East stated that it believed that the picks on the top of the Wabiskaw were within half a metre. In areas with collapse features, the range of error on the pick for the top of the Wabiskaw could be a metre or more. AEC East agreed that without a vertical well to compare its interpreted tops to, it was difficult to assess how accurate the picks were. Given the range of error, AEC East noted that the contour lines on its maps could easily be moved a metre either way. AEC East confirmed that the computer contouring was a function of the grid pattern it chose to input and that by changing the grid pattern, different structure interpretations were possible.

To calculate the volumetric initial gas-cap gas in place, AEC East planimetered its mapped small enclosures contoured to show the extent of proven and speculative free gas caps. It then used a regional average gas pay thickness of 1.2 m over the planimetered area. AEC East relied on a
70 per cent gas saturation, a fluid saturation of 30 per cent, and a regional porosity of 32 per cent derived from core. The fluid saturation represented both the water saturation and residual oil saturation present in the initial gas cap. In calculating the original bitumen in place, AEC East used an average of 3.5 m of bitumen pay derived from its regional mapping, 32 per cent porosity, a bitumen saturation of 70 per cent, and a water saturation of 30 per cent over the Goodwell lands in question and Section 13-82-22W4M.

AEC East stated that since its June 11, 1999, submission, a petrophysics review indicated that the reservoir parameters used should be revised. Accordingly, it used a 40 per cent water saturation for both the gas cap and bitumen reservoir, a 60 per cent bitumen saturation in the bitumen reservoir, and a porosity of 29.5 per cent representative of local conditions. In reviewing core analysis information, AEC East noted that the residual oil saturation in the gas cap could be as high as 45 per cent, as in the 07-9 well; 20 to 21 per cent, as in the 15-7 well; or between 12 and 15 per cent, as in the 14-17 well. A combination of these values could be used in assessing the residual oil saturation in the gas-cap areas. AEC East agreed that the use of the regionally derived 1.2 m for gas pay thickness was low in comparison to the 1.7 to 2.0 m observed in the area. It noted that it assigned the 1.2 m gas pay thickness over the entire planimetered area and estimated that if a 1.7 m gas pay thickness were used and a volume calculated using a pyramidal or trapezoidal formula, it would essentially reduce to the same pore volume. (See Appendix 4 for a comparative list of reservoir parameters.)

Initially, AEC East estimated the original gas in place at 1.98 10^6 m^3 and the original bitumen in place at 12.086 10^6 m^3. AEC East revised its original gas-in-place volume as a range of 8 10^6 m^3 to 10 10^6 m^3 and the original bitumen in place to 8.512 10^6 m^3. (See Appendix 3 for a comparative list of reserve estimates.)

AEC East did not agree with Goodwell's geological interpretation of the Wabiskaw because it did not incorporate the available regional data or review the available cores. AEC East stated that Goodwell's interpretation of a beach environment at very shallow water depths had too high an energy level to allow the preservation of the trace fossils that AEC East observed. The trace fossils would be preserved only if they were below the daily wave action or fair-weather wave base. On this basis, AEC East believed that the shale-filled channel interpreted by Goodwell, necessary to provide a stratigraphic trap for the gas cap as Goodwell interprets it, was not supportable. The Wabiskaw was not deposited in a beach environment, and therefore one would not expect tidal channels to be present. Further, AEC East noted that no evidence of these channels existed on a regional basis in the Wabiskaw A sandstone. Without a shale-filled channel there would be no trap, and without a trap there could be no significant gas cap.

AEC East criticized Goodwell's contouring methodology for optimizing the thickness of the sandstone above the drill-bit elevations to enhance the potential for gas-cap gas. AEC East also noted that every time the drill bit encountered shale due to the structural complexity of the area, Goodwell chose to interpret it as a facies change. AEC East also noted that the evidence did not support Goodwell's projection of a uniform gas/bitumen contact over a large area. It believed that annotations on horizontal strip logs did not provide independent verification of gas/bitumen contacts. In addition, the available well data in the area supported its experience that gas/bitumen interfaces were not predictable over large areas. AEC East noted that production data did not support the annotations regarding gas caps in the 1-35 and 1-14 wells and stated that even if a wellbore were in close proximity to a gas cap, gas coning from the horizontal well was likely to occur within days of production commencing.

AEC East criticized Goodwell's volumetric estimate of gas in place because it used a high temperature, which would tend to result in overestimation of its gas-in-place estimate. In response to questions, AEC East admitted that if corrected, Goodwell's gas-in-place estimate would actually tend to be an underestimate.

5.3.3 Views of the Board

The Board notes that both Goodwell and AEC East relied on volumetric estimates of the gas and bitumen reservoirs in their submissions and direct evidence. During the course of the proceeding, AEC East revised its volumetric estimate of the original gas in place and original bitumen in place. The changes in volumetric estimates during the proceeding highlight, in the Board's opinion, the difficulty in estimating the reserve on a volumetric basis.

The difference in methodology used by Goodwell and AEC East in developing their respective structure maps impacts the volumetric estimates of original gas in place, original bitumen in place, and original solution gas in place. The Board recognizes that both methodologies are interpretive. The Goodwell methodology, with respect to Wabiskaw data picks, is the least interpretive, since it relied on vertical data and initial horizontal well penetration data, attempted to verify breakouts at the top of the reservoir, and used drill-bit elevations within the sandstone to add some control. Goodwell did optimize the structure contouring above some drill bit elevations by assuming up to 5 m of additional sand above the bit elevations. From the available evidence, the Wabiskaw sandstone ranges from 2 to 5 m in thickness. Where the sandstone approaches 5 m in thickness, the lower 1 to 2 m tend to be of poorer reservoir quality. There are opportunities for different structural interpretations using Goodwell's own picks and gas/bitumen contact that could result in several gas caps rather than one.

The Board believes that, on balance, the evidence does not support the extrapolation of one gas/bitumen contact across the subject lands. The notations on the horizontal wells, the 1-35 and 1-14 wells, cannot be independently verified. Production data from the 1-35 and 1-14 wells do not appear to support gas production from an initial gas cap. The Board agrees with AEC East's evidence that a horizontal well would begin to cone gas-cap gas early in its productive life if the wellbore path were proximal to a gas cap. The Board notes that the limited information regarding gas/bitumen contacts in the area supports variable interfaces. The Board also agrees with AEC East's observation that variations in a gas/bitumen contact do not always imply separate accumulations of gas. In this case, Goodwell did not attempt to match the productive history of the wells to its gas-cap gas distribution on a well-by-well basis; rather it relied on a pad basis.

Goodwell used 29.9 per cent porosity for the gas cap, which the Board considers reasonable. However, assuming an 80 per cent saturation to optimize the gas volume is not supportable. A review of well control in the area to determine analog wells, water saturation calculations, and estimate of residual oil saturation would have been reasonably expected from any applicant in making its case with regard to the size of a gas cap on its lands.

Wellbore parameters for the bitumen reserve calculation at 62 per cent bitumen saturation and 29.9 per cent porosity were reasonable. However the planimetered area may have understated the bitumen reserves for two sections due to the gas optimization, and the use of 4.5 m bitumen pay for three sections likely overstated reserves for those sections. In the Board's opinion, Goodwell's estimate of gas-cap gas reserves overstates the case due to the overoptimization of the gas pay thickness and gas saturation and the extrapolation of the gas/bitumen contact to enclose all structure contours greater than +217.9 m asl.

AEC East relied on gamma ray methodology to develop its structure maps. While the gamma ray methodology may have its uses "in-house," it relies on assumptions that standardize the Wabiskaw reservoir to allow the predictions. The Board notes that AEC East agreed that there is no way to verify the predictions made using this technique. In addition, AEC East's evidence is that the karst-related chaotic structuring is endemic to the Wabiskaw in the area. Such an environment may not lend itself to simplifying and standardizing assumptions about the thickness and continuity of the reservoir for other than the most general purposes. AEC East admitted that the range of error in its method could exceed a metre or more in the complex structural areas of the reservoir and that the contours on its maps could easily be moved by at least a metre either way. In general, AEC East believed that the collapse features produced a complex structure under the subject lands. In this case, the Board believes that the use of the gamma ray method implies an accuracy that does not exist. The structural range on the interpolated picks at every 50 m in the horizontal wellbore may vary by a metre or more, while AEC East's evidence is that the gas cap does not exceed 2 m in thickness. The Board notes that AEC East's choice of input parameters for the computer-contouring package it used in developing its structure maps influenced the development of small isolated highs. There are opportunities for different structural interpretations using AEC East's own picks and range of gas/bitumen contacts that could result in several larger gas caps rather than the numerous small, isolated gas caps as interpreted by AEC East.

The Board believes that AEC East's use of a regionally derived 1.2 m gas pay is inappropriate when compared to the closest offset wells with gas pay. AEC East noted that of the 40 vertical wells in the area, only 5 had gas pay and the average gas pay in the vicinity was 1.7 to 1.8 m. AEC East did not support its assumption that a pore volume calculated using a 1.2 m thickness over a block area would be equivalent to a pore volume calculated using a 1.7 m thickness in a pyramidal or trapezoidal formula calculation. In addition, this is inconsistent with AEC East's interpretations of free gas caps or potential free gas caps as the map contours generally enclose a 2.0 m structure interval, implying 2.0 m of gas pay.

AEC East revised the reserve estimates that it wished the Board to rely on in reaching its decision. The reservoir parameters that AEC East reported it would use on a go-forward basis were 29.5 per cent porosity, 40 per cent water saturation, and 60 per cent bitumen saturation. It was unclear as to whether the gas saturation would be 60 per cent or some lesser value after the residual oil saturation was taken into account. AEC East put forward a range of residual oil saturations from 12 to 45 per cent. While AEC East provided a range of original gas in place for the Board to consider, it is unclear to the Board how the estimate was arrived at. Similarly, with the revisions to its original bitumen-in-place estimate, it is unclear to the Board as to what parameters AEC East relied on to arrive at the new reserve estimate. In the Board's view, AEC East's gamma ray and mapping methodology tends to underestimate the gas cap gas area and does not account for the high GORs of a number of individual wells.

The Board notes the considerable testimony with regard to the Wabiskaw depositional environment and the impact the different interpretations may have on the potential size of the gas cap or gas caps in the subject area. Goodwell's interpretation allowed for shale-filled channels that created an updip stratigraphic trap for gas-cap gas accumulation. AEC East's interpretation focused on karst-related collapse features creating small, isolated highs that had the potential for gas accumulation. Goodwell argued that the well log features it relied on were in some cases the very features that AEC East relied on to argue karst-related collapse features.

Regardless of which interpretation is the commonly accepted, the 13-30 and 4-31 wells do not have evidence of gas and are structurally the highest wells in the area. The Board believes that production from the reservoir indicates that an initial free gas cap or caps are or were present; therefore, barriers to gas migration must exist, be they shale-filled channels or a series of interconnected collapse features filled with shale. Further, the Board notes that not all of the horizontal wells produce as if producing from a free gas cap. Therefore, it is likely that more than one discrete gas cap exists under the subject lands and Section 13-82-22W4M.

In its technical review of the evidence, the Board generated a structure map to develop a comparative estimate of the free gas-cap gas and bitumen reserves over the subject lands and Section 13-82-22W4M. The Board believes that an approach similar to that of the applicant's is the least interpretive when making picks on the top of the Wabiskaw and, therefore, modified the Goodwell structure map for its use. Modifications included removing the overoptimized structure contouring above the sand bit elevations in the subject lands area and Section 13-82-22 W4M. The Board reviewed early production from each well to determine whether the well was producing free gas-cap gas or producing as a typical bitumen well. As a result, the Board modified the structure map to reflect well isolation where warranted. From this information, and recognizing how limited and interpretive the data are, the Board concluded that five discrete gas caps exist over the subject lands and Section 13-82-22 W4M. The Board used variable gas/bitumen interfaces, as suggested by the evidence, located gas caps over wells indicative of free gas-cap gas production, and used a maximum 2 m gas pay thickness in determining the size and location of the gas caps.

To estimate the original gas in place, the Board planimetered the gas caps and derived wellbore parameters from the average of the two nearest vertical wells with gas caps, the 15-7 and 14-17 wells. Both these wells were also cored. The Board determined porosity and the residual oil saturation from the core analysis as 30 and 14 per cent respectively. It determined the water saturation from log analysis as 28 per cent. This results in a gas saturation of 58 per cent.

The Board derived bitumen reservoir parameters and generated a bitumen pay map from core and log evaluations on 18 vertical wells in the immediate area. The parameters are 28 per cent porosity, 45 per cent water saturation, and a 55 per cent bitumen saturation. The Board used consistent cutoffs and constants in a computer-based well evaluation system to arrive at the reservoir parameters. The gas cap has a slightly higher average porosity than the bitumen zone because the best-quality reservoir occurs near the top of the Wabiskaw sand. The lower water saturation also reflects the improved reservoir conditions near the top of the sand. The bitumen evaluation averages all the porosities and water saturation over the entire zone, including that portion of the lower shalier interval that meets cutoffs. The Board planimetered its bitumen pay map to estimate the original reserves of bitumen in place. The average bitumen pay thickness over the subject lands and Section 13-82-22W4M was 3.0 m. (See Appendix 4 for a comparative list of reservoir parameters.)

Using the noted parameters, the Board calculated the original gas in place under the lands in question and Section 13-82-22W4M as 20.9 10^6 m^3. The Board determined the original gas in place under only the Goodwell lands to be 18.12 10^6 m^3. Neither calculation included any possible gas cap attributable to the 15-7 well on the south portion of Section 18-82-21W4M. The Board calculated the original bitumen in place under the subject lands and Section 13-82-22 W4M as 7.2 10^6 m^3. The Board determined the original bitumen in place under only the Goodwell lands to be 5.3 10^6 m^3. (See Appendix 3 for a comparative list of reserve estimates.)

5.4 Pressure and Material Balance Estimates

5.4.1 Views of the Applicant

Goodwell stated that it did not conduct material balance calculations to support its volumetric reserve estimates. Goodwell questioned the accuracy of the pressure measurement given that adjacent wells only 400 m away were producing during the survey.

5.4.2 Views of the Interveners

AEC East used pressure analysis from two analog wells, 9-18 and 3-30, with reported pressures of 770 and 1751 kilopascals (kPa) respectively to calculate a weighted-average reservoir pressure of 1100 kPa for the drainage area in the subject lands. AEC East argued that it chose to ignore the six lower pressure data points taken from wells on the subject lands, since they may not have been fully built up and did not represent the entire drainage area.

AEC East performed material balance calculations, using the volumetric original gas and bitumen in place, to predict the pressure in the subject area at the end of February 1999. It submitted that there was a close match between its material-balance-predicted pressure and the weighted-average pressure calculated for the subject lands and that this confirmed that the in-place reserve values assumed in the material balance must be reasonable and valid.

Renaissance did not submit evidence but questioned AEC East on its material balance analysis. AEC East conceded in cross-examination that the analysis using the 9-18 analog well to determine the weighted-average reservoir pressure for the subject lands did not include its unreported production. Renaissance argued that the material balance, if conducted with the unreported production, would have predicted a much lower reservoir pressure. If this lower pressure were used in the weighted-average, AEC East would not have had a close match between the material-balance-predicted pressure and the calculated weighted-average pressure. Renaissance also suggested in its questioning that the material-balance-calculated values could be solved if a much larger gas in place were assumed. AEC East did not disagree with Renaissance’s suggestions.

5.4.3 Views of the Board

Material balance and other performance indicators can often be used to clarify and even provide a more accurate estimate of recoverable reserves, especially where wellbore data are limited or geology is complex. Unfortunately in this case, the Board believes that material balance calculations do not yield a level of accuracy or verification that assists in resolving reserve estimates. The reliability of estimating a potentially large gas cap, given the limited pressure data and missing production data, does not validate one volumetric model over another. The Board will not put weight on material balance numbers in its consideration. In reaching this conclusion, the Board notes that AEC East did not submit any detailed test information for the 9-18 and five other wells that would allow the Board to substantiate the validity or usefulness of the test results. Such information is required in accordance with EUB *Guide 40: Pressure and Deliverability Testing—Minimum Requirements and Recommended Practices*.

AEC East submitted the January 1999 pressure survey for the 15-30 well with the required test details in accordance with *Guide 40*. It showed a static pressure of about 600 kPa, which appears low in view of production characteristics.

The Board believes that the extrapolated buildup pressure of the 3-30 well is highly interpretive. The Board extrapolation of the same data would result in a significantly lower pressure than the 1751 kPa suggested by AEC East.

It is unfortunate that upon notice of a right-to-produce dispute and the need to address the conservation impact of producing gas over bitumen, AEC East did not make a greater effort to obtain reliable pressure data.

5.5 Solution Gas Production

5.5.1 Views of the Applicant

Goodwell stated that gas production from the subject wells had been a composite of free gas or gas-cap gas and solution gas. It argued that it was not possible to distinguish between gas-cap gas and solution gas production.

Goodwell estimated the volume of original solution gas in place underlying its lands to be 60.19 10^6 m^3. This estimate was based on an original bitumen in place of 8.11 10^6 m^3 and an initial solution GOR ratio of 7.4 m^3/m^3. The applicant stated that it was willing to accept that solution gas recovery would be in the range of 60 to 75 per cent. Goodwell did not provide an estimate of evolved solution gas.

To support its argument that gas-cap gas had been produced by the wells on the subject lands, Goodwell assumed that no original gas cap or free gas was present on its lands, in which case all gas produced would have been solution gas. Using this assumption, Goodwell estimated that solution gas production to July 31, 1999, would have been 54.136 10^6 m^3, or 65.19 per cent of its original solution-gas-in-place estimate. Furthermore, it found that this solution gas production volume, when split on the basis of north and south halves of each pad, exceeded the solution gas recovery factor anticipated by Goodwell and AEC East. In fact, Pad E5 and the south half of Pad E6 would have recovered more than 90 per cent of Goodwell's estimated original solution gas in place for those pads. On this basis, Goodwell concluded that gas-cap gas production must have occurred in addition to solution gas production.

Goodwell suggested that the low viscosity of the Athabasca Wabiskaw-McMurray bitumen would impede massive flow of solution gas. In addition, Goodwell noted that seeing the high gas rate at the subject wells as a result of the evolved solution gas moving ahead of the bitumen was not consistent with the low GORs observed at the structurally high wells located north of the subject area.

5.5.2 Views of the Interveners

AEC East stated that the majority of the gas produced from the Goodwell lands was solution gas that had evolved from the bitumen as a result of pressure depletion. AEC East acknowledged that original gas-cap gas production may have occurred in the past and may continue to occur, but maintained that it was very small compared to solution gas production.

AEC East estimated the total solution gas in place contained in the bitumen underlying the subject area and Section 13-82-22W4M to be 64.691 10^6 m^3. It used an original bitumen in place of 8.512 10^6 m^3 and an initial solution GOR of 7.6 m^3/m^3 to estimate the total solution gas in place. AEC East further submitted that, based on a pressure of 1100 kPa at the end of February 1999, the volume of solution gas that had evolved out of the bitumen to that date amounted to 31.068 10^6 m^3. It suggested that a reasonable recovery factor for evolved solution gas would be in the range of 75 to 80 per cent, resulting in evolved solution gas production of 23.301 to 24.855 10^6 m^3 to February 1999. AEC East confirmed that the difference between the latter and the 30.72 10^6 m^3 of actual gas production to that date would have been gas-cap gas production. AEC East calculated a gas-to-bitumen mobility ratio of 8.47, which, it stated, clearly indicated that the evolved gas would travel faster through the reservoir than the bitumen. Furthermore, AEC East stated that the small original gas caps had provided a pathway for the evolved solution gas to migrate to the wellbore. AEC East suggested that the fact that the producing GORs of the subject wells were greater than the pressure/volume/temperature (PVT)-analysis-based solution GOR of 8.32 m^3/m^3 was evidence that solution gas was evolving from the bitumen and migrating preferentially to the bitumen producers.

AEC East identified Pad E3, where the GOR was initially less than 100 m^3/m^3 and had increased to 200 m^3/m^3, as typical GOR behaviour of a Wabiskaw bitumen well without an initial gas cap. In contrast, the other three pads (E4, E5, and E6), which had had significantly higher initial GORs that had since declined, were characterized as typical bitumen producers from reservoirs with small isolated gas caps.

AEC East criticized Goodwell for its failure to use reservoir engineering, namely, pressure analysis and material balance calculations, to support its hypothesis of a large gas cap on the subject lands. AEC East submitted that the evidence presented by Goodwell did not support the conclusion that a significant initial gas cap existed or currently exists on the subject lands. Therefore, AEC East maintained that any produced gas, especially from now on, was primarily solution gas for which AEC East has the right to produce.

5.5.3 Views of the Board

The Board agrees with Goodwell that the gas produced to April 1999 from Pads E4, E5, and E6 on the subject lands exceeded the expected recoverable evolved solution gas volume. Therefore, gas production to that date was a combination of gas-cap and solution gas production. However, the Board believes that there are insufficient reliable data to accurately quantify the volume of evolved solution gas production. This seriously impacts on the ability to calculate an estimate for the remaining volumes of original gas-cap gas.

The Board estimates a total solution-gas-in-place volume of 54.0 10^6 m^3 for the subject area and Section 13-82-22W4M. This estimate is based on an original bitumen in place of 7.2 10^6 m^3 and an initial solution GOR of 7.5 m^3/m^3. With respect to the evolved solution gas, the lack of pressure data for this area precludes accurate estimates. The Board points out that if the low pressure measured at the 15-30 well truly represents this area, the evolved solution gas production to April 1999 could have been as high as 25 10^6 m^3, which would imply a significant remaining original gas cap in place. On the other hand, if the reservoir pressure in this area were 1100 kPa, the remaining gas cap in place would be less but still not insignificant if the EUB’s higher volumetric in-place gas-cap reserves were assumed.

The Board agrees with AEC East that the gas caps overlying the Goodwell lands are likely providing a pathway for evolved solution gas to migrate to the wellbore. Furthermore, the Board also agrees with both AEC East's and Goodwell's position that the current GORs of Pad E3 are indicative of solution gas production.

5.6 Well GOR Performance

5.6.1 Views of the Applicant

Goodwell compared gas production from 18 wells operated by Amoco Canada Petroleum Company located in Twp 80-22W4M, for which Goodwell also owns the P&NG rights and calls the Southern lands, to production from the subject wells on the subject lands. Goodwell noted that the average GOR of the subject wells was 25.5 times greater than that from the Southern wells and the actual gas production volume 15.7 times greater during the third quarter of 1998. Goodwell suggested that this large discrepancy must indicate that solution gas and gas-cap gas production was occurring from the subject lands.

Goodwell criticized AEC East's interpretation of the GOR trends for wells on the subject lands. Goodwell identified several wells in the subject area that had declining GOR trends. Goodwell questioned how AEC East could interpret the declining GOR trends at wells within the subject lands as bitumen wells producing only solution gas when, by its own analysis, AEC East argued that wells producing only solution gas exhibited a gradual increase in GOR trends due to increasing evolved solution gas production.

5.6.2 Views of the Interveners

AEC East argued that increasing GOR trends were to be expected from wells not associated with a gas cap. The increasing GOR trend was the result of producing evolved solution gas as the reservoir pressure was depleted. AEC East stated that the evolved solution gas migrated to supplement the initial gas caps located in structural highs. From its analysis of wells within and to the west of the Goodwell lands, AEC East speculated that GORs of 200 m^3/m^3 or more could be attributed entirely to solution gas drive. AEC East stated that if GORs were high early in the production period, it would interpret this trend to indicate the presence of a small initial gas cap.

5.6.3 Views of the Board

The Board agrees with AEC East that solution gas production will increase as the reservoir pressure declines, that high GORs early in the production life indicate a gas cap, and that evolved solution gas will replenish depleted gas caps to some extent.

The Board agrees with Goodwell's observations that several wells within the subject lands produce at GORs many times the magnitude found in the referenced Southern lands, where no gas caps are known to exist. The Board agrees with Goodwell's interpretation that gas production of the magnitude and trend exhibited by the subject wells is indicative of solution gas and gas-cap production.

Using the public database, the Board has reviewed the GOR performance of the subject wells and identified four wells within the subject lands with distinctively high GOR production trends. It is the Board's view that these wells are producing volumes of gas in excess of that of solution gas. The 1-13 well produced at a GOR of 960 m^3/m^3 after only four months of production and is currently delivering 1320 m^3 of gas per m^3 of bitumen. The 2-13 well began producing at a GOR of nearly 700 m^3/m^3 and is currently delivering 660 m^3 of gas per m^3 of bitumen. The 02/11-18-21W4M well began producing at a GOR of 1275 m^3/m^3 and is currently delivering 730 m^3 of gas per m^3 of bitumen. The 9-18 well began producing at a GOR of 2150 m^3/m^3 and is currently delivering 765 m^3 of gas per m^3 of bitumen.

With the likelihood of an original gas cap reserve remaining, the Board concludes that these four wells are producing gas-cap gas.

6 NEED FOR THE SHUT-IN

6.1 Views of the Applicant

Goodwell submitted that, based on its interpretation of volumetric reserves, production estimates, and an unknown but sizable evolved solution gas volume, a significant initial gas cap remains and that much of the current gas production from the subject lands is gas-cap gas (see Appendix 3). As noted earlier, AEC East has the right to produce bitumen but not gas-cap gas and such gas production must be shut in. Goodwell testified that the remaining gas cap is a significant issue that should be dealt with and not left for later resolution. Goodwell said that continued production would permit AEC East to continue to expropriate Goodwell's gas and would ultimately lead to its depletion. Goodwell submitted that AEC East, by producing the gas cap, has essentially seized an asset that belongs to another party. Even if payment were made for the resource, Goodwell argued that AEC East has forced the sale of its gas resource.

Goodwell also said that the Board should take direct shut-in action to protect conservation until it can be shown that the reservoir can be produced in a manner that is not wasteful of either the bitumen or the gas-cap reserves.

6.2 Views of Interveners

AEC East acknowledged that Goodwell held the P&NG rights to the subject area from which AEC East was currently producing bitumen. AEC East stated that it and Amber were fully aware of the split-rights issue and recognized that it would have to account to the P&NG owners if any significant volumes of gas-cap gas were produced from the bitumen wells.

AEC East argued that the initial gas caps were very small and were for all practical purposes depleted (see Appendix 3). It believed that the vast majority of gas that had been and was currently being produced was solution gas that evolved from bitumen as a result of pressure depletion and that AEC East owned this gas. However, AEC East conceded that there might be some minor initial gas cap contribution, but it stated that the volume was very small compared with the solution gas contribution. It argued that such incidental volumes should not cause the

Board to take very severe and one-sided action. If the Board shut in the subject wells, it would give Goodwell an unfair advantage.

AEC East said that both parties had the legal right to produce their respective leased substances and that it was not necessary to shut in the subject wells because AEC East was measuring and conserving gas production. AEC East said that it was prepared to compensate Goodwell upon determination of the volume of conserved gas attributable to the gas cap. AEC East suggested to Goodwell that they refer both technical positions to an independent commercial evaluator to determine the volume and associated value of any gas-cap reserves. Value would be determined using JP-95[4] procedures, with full bitumen development costs used to determine Goodwell's share of production costs. It claimed that this would follow normal industry practice. AEC East speculated that a Board decision to shut in the subject area wells until a production-sharing agreement was reached did not guarantee that Goodwell and AEC East would be able to reach an agreement. Given the absence of the Board having empowering legislation to regulate such a production-sharing agreement, the shut-in order would only serve to place AEC East in a untenable position, given its investment, compared with Goodwell, which had no economic force requiring it to act reasonably.

In final argument, Renaissance said that the Board should issue an order requiring AEC East to apply for a Class-I approval and that, until such time as it received that approval, all of the subject wells should be shut in. Renaissance also suggested that the EUB consider some sort of production allocation, GOR penalty, or GPP regulations to provide optimization of primary bitumen recovery.

6.3 Views of the Board

After considering the evidence, the Board finds that on balance the available data indicate that a sizable original gas cap of about 18.12 10^6 m^3 was present in the subject lands. The performance data normally available at this point of depletion for comparable pools of reasonable quality are not available to assist in quantifying production. However, the Board finds that it is reasonable to conclude that starting with a gas cap of this magnitude, a sizable volume remains. Accordingly, the Board believes that it must decide if it is appropriate in these circumstances to allow production to continue, given the equity and conservation mandates.

While it is impossible to determine precisely whether the source of current gas production from a given well is gas-cap gas, evolved solution gas, or a combination of both, the many lower-GOR wells exhibit producing characteristics supportive of evolved solution gas.

There are four wells (1-13, 2-13, 02/11-18 and 9-18), however, whose performance and geological position show that they are producing significant gas volumes. In the opinion of the Board, much of this production is original gas-cap gas production. The Board believes such production is in contravention of the well licences and may impact bitumen recovery. Therefore, the Board considers that it is necessary and appropriate to shut in the four high-GOR wells. The Board does not believe that the shut-in of additional wells is warranted at this time.

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[4] As per Joint Industry Task Report on Processing Fees (JP-95).

The Board, in reviewing the wide differences in the companies' volumetric estimates, can understand the parties reaching very entrenched and polarized positions. The absence or questionable quality of performance data precluded the parties from conducting a cross-check of their interpretations. The extensive changes during the course of the hearing are further evidence of the interpretative nature and uncertainty arising from lack of good data. The Board believes it is imperative to collect the necessary information for cases of split rights and gas over bitumen in better quality reservoirs. It is not clear to the Board whether the Oil Sands Regulations set out an appropriate set of requirements to cover the wide range of producing situations that are becoming evident for declared bitumen properties. This matter should be the subject of a regulatory review with stakeholders.

Even with adequate data, it appears from the evidence in this sample case that companies may not fully understand the implications of split mineral rights and gas-over-bitumen requirements. Forming a position around a GOR of 1800 m^3/m^3 benchmark can preclude an operator from acknowledging other points of view and delay recognition of a problem. The Board believes that parties must fully appreciate the split mineral rights issue and work collectively to identify and resolve disputes. Early identification of an issue is preferred. Hearing argument after large investments have been made is not in the public interest. The regulatory review should address early operational expectations.

Finally, while the focus of the hearing was on equity and gas-over-bitumen conservation issues, the Board is concerned about the low bitumen recovery observed to date for what appears to be a moderately good-quality pool. While AEC East could not provide an estimate of bitumen recovery for this area, it did indicate that recoveries in the order of 7 to 8 per cent were possible. The evidence in the hearing suggests recovery to date is only 2 per cent after an extensive pressure decline. The Board expects ultimate recovery to be relatively low. One explanation is a smaller bitumen pool. Also, it would appear that the gas cap did not or was not allowed to provide additional energy support. The Board will require AEC East to prepare a detailed technical review of the bitumen depletion and evaluate options to optimize recovery. This study must address both current and future depletion plans.

The Board does not support AEC East's contention that its right to produce leased substances under its oil sands leases may include the production of initial gas-cap gas. AEC East's interests in this pool include only bitumen and solution gas. Accordingly, AEC East must obtain all of the rights to produce overlying gas through some form of agreement or revenue-sharing formula. The question of past production and potential lost revenues are outside the EUB's jurisdiction. The Board must, however, ensure that continued production is in full compliance with the regulations.

7 OTHER MATTERS—Venting of Gas to the Atmosphere and Measurement

7.1 Views of the Applicant

Goodwell submitted that during the period from the on-production date in December 1997 to commencement of gas conservation in June 1998, the subject wells vented approximately 28.188 $10^6 m^3$ of gas to the atmosphere. Goodwell stated that venting of significant volumes of gas constituted a breach of Section 11 of the Oil Sands Conservation Regulation and Section 8.080(1) of the Oil and Gas Conservation Regulation. Under these requirements, an operator must flare, and not vent, any significant volumes of produced gas.

Goodwell expressed the concern that, apart from the fact that a significant amount of vented gas belonged to Goodwell, the direct venting of such large quantities of natural gas into the atmosphere, especially methane, represented a serious pollution hazard and waste of a valuable resource. It stated that a consequence of such venting was the unnecessary increase in greenhouse gases and the loss of the economic benefit of the resource to the province, both in the form of payment for the rights to the gas and the lost royalties on its production.

Goodwell complained that AEC East conducted no measurement of gas volumes during the six or seven months of venting, nor did it report any gas production volumes to the EUB until July 1998.

Goodwell ascribed an attitude of indifference to AEC East’s explanation for its venting practices. According to Goodwell, Amber, which owned and operated the wells during the time of venting, did not have the rights to the vast quantities of gas being vented, so it did not care that the gas was not being conserved. This was further evident in the operator not measuring gas volumes in the initial production period, although there must have been field indicators of large volumes.

In cases of split rights, Goodwell endorsed a practice of early and accurate testing of GORs, pressures, and flow capacity, followed by required suspension of any well found producing gas-cap gas, pending an evaluation of the economic viability of conserving the gas reserves. The P&NG rights holder would then be contacted and arrangements made for putting the well back on production.

Goodwell urged the Board to re-examine its regulations and practices regarding the venting of gas associated with bitumen production. It stated that current EUB regulations regarding the venting of gas associated with bitumen operations were more applicable to pure bitumen, where insignificant amounts of gas were likely to be found, than in the subject area.

7.2 Views of the Interveners

AEC East submitted that Amber’s venting activities in the subject area were in compliance with EUB requirements and conducted with EUB approval. AEC East submitted that the EUB approved venting through a letter dated February 10, 1998. In addition to adhering to these requirements, AEC East testified that Amber’s venting operations represented GPP, in keeping with other operators in the Pelican Lake area. It stated that the amount of gas that was vented to the atmosphere totalled approximately 14.1 10^6 m^3, not the 28.188 10^6 m^3 contended by Goodwell, and that by the summer of 1998 Amber had decided to conserve the gas by tying the subject wells and some 74 others into a common gathering system.

AEC East submitted that the volumes of gas vented from December 1997 to May 1998 were not necessarily out of line with the volumes of gas vented on a field basis in a regional context. It was not until June and July 1998, when GOR testing revealed that some of its wells were venting over 0.5 10^6 m^3/month each, that it decided to seriously consider conserving the gas.

AEC East contended that the determination of what constituted "…any significant amount of gaseous or liquid hydrocarbon…" under Section 11 of the Oil Sands Conservation Regulation was inextricably linked to the economic feasibility of conserving the gas. This decision was difficult to make in the early production life of a well, since a high initial GOR was not necessarily sustained by wells in the Pelican Lake region. It believed that its conduct in venting the subject wells for the first six or seven months of production before conservation efforts were introduced was reasonable in light of these circumstances.

AEC East maintained that it had not breached Section 8.080(1) of the Oil and Gas Conservation Regulations by failing to flare or otherwise burn the vented volumes of gas. It stated that it was following standard industry practice in the area. Furthermore, it argued that there were valid operational concerns that favoured venting over flaring. Specifically, during the winter months the water-saturated gas may cause hydrate formation within the in-line flame arrester, requiring significant capital costs to prevent. Other increased costs associated with flaring included propane costs for the flare flame pilot and on-site electrical power.

AEC East submitted that it was also in compliance with the measurement of natural gas requirements as set forth in the EUB's *Informational Letters (IL) 91-3* and *91-9*. It stated that Amber had received a Class-II measurement approval from the EUB in connection with its development scheme approval. AEC East interpreted the informational letters as obliging it to conduct an initial GOR test within six months of the start-up of production and to undertake future measurements annually over the next three years depending on the GOR test results. It based this view on the fact that each of the subject wells operated as single-well batteries, with production from each well being transported to its own storage tanks. It stated that the requirement to continuously measure over 2000 m^3/d of gas only applied to wells that had been flow-lined together.

AEC East acknowledged that in future cases where potential conflicts may arise between bitumen and natural gas owners, more frequent, early, accurate testing and measurement of the gas production would greatly aid in determining whether it was initial gas cap gas being produced in association with the bitumen. It submitted that an initial GOR of 1800 m^3/m^3 might be a good benchmark to indicate the presence of initial gas-cap gas and that more extensive early testing and measurement would lead to a more definitive determination of an initial gas cap and to the resolution of the issues arising from such a determination.

7.3 Views of the Board

The Board commends AEC East's decision to initiate gas conservation for the area of application and a large surrounding area relatively quickly. However, the Board is disappointed with AEC East's explanations concerning venting. Venting of this magnitude of gas is unacceptable. Flaring, not venting, of significant volumes of gas is a long-standing Alberta regulatory requirement. Recognizing that "significant" is not quantified, the Board's general practice has been to require flaring for amounts that are large enough to measure. This would in many cases be in the order of 500 m^3/d well. Initial requirements are usually addressed in applications under *ID 91-3*. Using these guidelines and the benefit of hindsight, all the subject wells exhibit gas production volumes large enough to require flaring, and this should have occurred. The absence of accurate well production data is the principal cause.

The Board will invite DRD, CAPP, and SEPAC to participate in a review of the regulatory needs, documentation of requirements, and operating practices appropriate for the wider range of producing situations becoming evident for declared bitumen[5]-producing wells.

DATED at Calgary, Alberta, on March 31, 2000.

ALBERTA ENERGY AND UTILITIES BOARD

J. D. Dilay, P.Eng.
Board Member

T. McGee,
Board Member

R. J. Willard, P.Eng.
Acting Board Member

[5] As per Part 1(2)(d) and (e) of the Oil Sands Conservation Regulations.

Appendix 1 Subject wells—Well locations and abbreviated reference

Location	Abbreviated reference
Pad E3	
00/03-13-082-22W4M/0	3-13
00/04-13-082-22W4M/4	4-13
00/03-36-082-22W4M/0	3-36
00/04-36-082-22W4M/5	4-36
Pad E4	
00/01-13-082-22W4M/0	1-13
00/02-13-082-22W4M/0	2-13
00/15-25-082-22W4M/3	15-25
00/01-36-082-22W4/M3	1-36
Pad E5	
00/11-18-082-21W4M/0	11-18
02/11-18-082-21W4M/2	02/11-18
00/13-30-082-21W4M/2	13-30
00/14-30-082-21W4M/2	14-30
Pad E6	
00/09-18-082-21W4M/0	9-18
00/10-18-082-21W4M/3	10-18
00/15-30-082-21W4M/2	15-30
00/16-30-082-21W4M/4	16-30

Appendix 2 Well locations and abbreviated reference

Location	Abbreviated reference
AA/14-05-082-21W4M/0	14-5
AA/15-07-082-21W4M/0	15-7
AA/14-17-082-21W4M/0	14-17
AA/13-30-082-21W4M/0	13-30
00/04-31-082-21W4M/0	4-31
00/04-01-082-22W4M/0	4-1
00/10-01-082-22W4M/0	10-1
00/10-13-082-22W4M/0	10-13
00/07-09-082-22W4M/0	7-9
00/01-14-082-22W4M/2	1-14
00/03-30-082-22W4M/4	3-30
00/01-35-082-22W4M/3	1-35

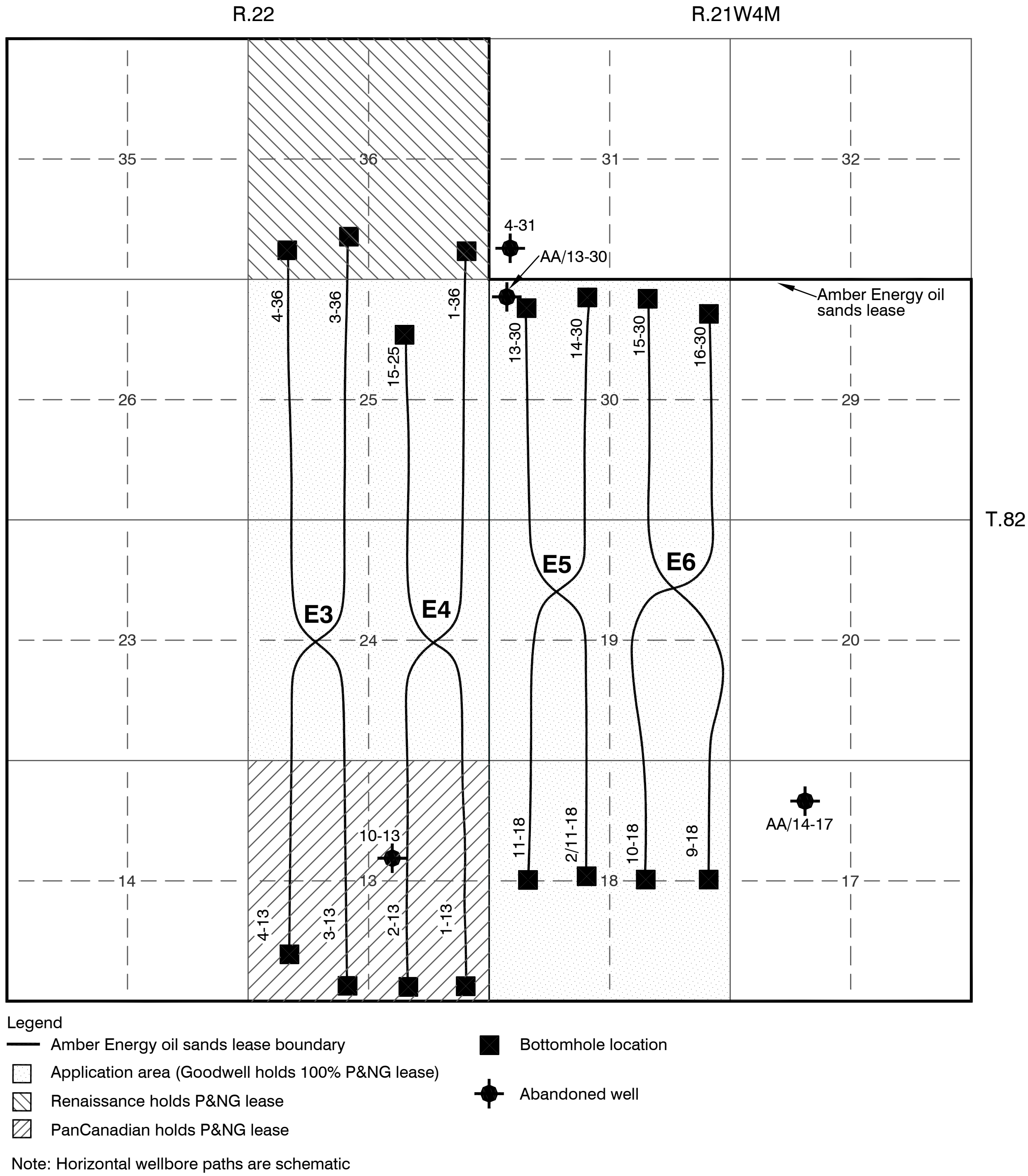
Appendix 3 Comparison of unreported production, reported production, and reserves for the Brintnell area ($10^6/m^3$)

	Goodwell	AEC East	EUB
Unreported gas production	28.188	11.99	11.0
Total gas production, March 1, 1999	46.9	30.72	29.7
Total gas production, Jan 1. 2000	58.9***	42.71***	41.7***
Original gas in place, volumetric	76.4*	8-10**	20.9 **, 18.12*
Original gas in place, material balance	N/A	8-10**	N/A
Original bitumen in place	8.11*	8.512**	7.2 **, 5.3*
Original solution gas in place	60.19*	64.691**	54.0**
Evolved solution gas, Feb. 1999	No reliable pressure data	23 to 25	No reliable pressure data
Evolved solution gas, Dec. 1999	N/A	N/A	N/A
Remaining initial gas cap in place, Dec. 1999	Very significant	Very small to nil	Sizable

* Subject lands only.
** Subject lands and Section 13-82-22W4M.
*** Production values derived by the EUB using public database.

Appendix 4 Comparison of reservoir parameters used

	Goodwell	AEC East		EUB
		Initial	Revised	
Gas reservoir parameter				
Porosity	29.9	32	29.5	30
Water saturation, S_w (%)	~10	30 (S_w + S_{or})	40	28
Residual oil saturation, S_{or} (%)	~10	30 (S_{or} + S_w)	12-45	14
Gas saturation (%)	80	70	60-15 (unclear)	58
Gas/bitumen contact	+217.9 m asl	variable	variable	variable
Bitumen reservoir parameter				
Porosity (%)	29.9	32	29.5	28
Water saturation (%)	38	30	40	45
Bitumen saturation (%)	62	70	60	55



Pelican Lake AEC Pad Number and Well Identification

Application No. 1039128

Goodwell Petroleum

Decision 2000-21