Decision **2003-023**

Chard Area and Leismer Field
Athabasca Oil Sands Area

Applications for the Production and Shut-in of Gas

March 18, 2003

Alberta Energy and Utilities Board

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Attachment

Computer disk containing the decision report and closing arguments of the hearing participants

EXECUTIVE SUMMARY

During November 2001 to June 2002, the Alberta Energy and Utilities Board (Board) held a hearing to consider 27 applications from various parties, some respecting the shut-in of gas wells and others for the approval to produce gas wells in the Chard area and Leismer Field (Chard-Leismer). The applications included a total of 145 wells.

The Board concludes that the bitumen resources within the Wabiskaw Member of the Clearwater Formation and McMurray Formation (Wabiskaw-McMurray) in the Chard-Leismer area are on trend with Alberta's most significant bitumen deposits, and it notes that most announced and approved commercial steam-assisted gravity drainage (SAGD) projects fall within this trend. The Board believes that a significant amount of potentially recoverable bitumen exists in the Chard-Leismer area that warrants consideration for protection for future development. The Board further believes that there is currently insufficient understanding of the capabilities and limitations of SAGD to definitively establish commercial bitumen pay criteria. Therefore, until more information becomes available, the Board believes that it should continue to use the criteria outlined in *Interim Directive (ID) 99-1*.[1]

The Board also finds no reason to move away from its definition of a region of influence, as set out in *ID 99-1*, nor from its understanding of the regional hydrogeology of the Athabasca Oil Sands area (including Chard-Leismer), as discussed in *Decision 2000*-22.[2] The Board believes that the theory of hydraulic continuity is fundamental to the interpretation of subsurface hydrogeological data at a regional scale and to the interpretation of regions of influence at a smaller scale.

The Board believes that some Wabiskaw-McMurray gas in the Chard-Leismer area is or has the potential to be associated with underlying channel bitumen, either through direct vertical continuity or indirectly through lateral continuity of the gas and top water zones, similar to the Surmont area. This is based on the Board's interpretation of the occurrence of extensive and randomly distributed thick bitumen-saturated channel sands that are in direct communication with overlying gas and top water zones. However, unlike the Surmont area, the Board interprets the existence of regionally correlatable mudstones and shales in some parts of the Chard-Leismer area. Where these mudstones and shales are present, the Board believes they act as barriers to vertical pressure transmission between Wabiskaw-McMurray gas and underlying channel bitumen.

There continues to be very limited applicable field experience regarding the effect of associated gas production on SAGD bitumen recovery. As a result, the Board must continue to rely on reservoir modelling to evaluate the issue. The Board believes that a major factor involved in modelling is the geological description used. In general, the hearing participants used either generic models or well-specific models to develop geological descriptions. Considering the complex nature of the Wabiskaw-McMurray, the Board believes there are limitations to both approaches. Additionally, while the inclusion of reservoir heterogeneities such as thief zones

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[1] EUB *Interim Directive (ID) 99-1: Gas/Bitumen Production in Oil Sands Areas—Application, Notification, and Drilling Requirement*, February 3, 1999.

[2] EUB *Decision 2000-22: Gulf Canada Resources Limited, Request for the Shut-in of Associated Gas, Surmont Area,* March 2000.

adds complications to modelling, the Board believes that where they occur, their effects should be considered. Another important factor involved in modelling is the operating strategy. The Board believes that operating strategies used in models may not always be possible to implement in the field and that this needs to be kept in mind when considering the results of model studies. Furthermore, the Board believes that bitumen recoveries should be compared on a net energy basis to account for the fuel requirements for SAGD schemes. The Board also acknowledges that a number of risk factors not included in most of the model studies need to be considered. On the basis of its assessment of the model studies, the Board concludes that producing gas that is associated with bitumen presents an unacceptable risk to SAGD bitumen recovery.

The Board believes that there would be no significant geomechanical effects in a bitumen zone due to SAGD injection pressures at or below injection pressures of 2000 kilopascals absolute (kPaa) in the area of Newmont's Leismer oil sands leases. Since the virgin gas zone pressures in the area are in the order of 2000 kPaa, whether or not an overlying gas zone is produced, the gas zone pressure would be below the level at which significant geomechanical effects would occur.

The Board acknowledges that in some situations repressuring of a depleted Wabiskaw-McMurray gas zone may be shown to be a viable option in the future, but it continues to believe that repressuring should not be relied on until it has been proven to be feasible and practical on the basis of field tests. The Board therefore encourages repressuring projects, such as that jointly proposed by EnCana Corporation and Devon Canada Corporation at Christina Lake. However, the Board believes that even if some repressuring projects were ultimately successful, the viability and practicality of such projects would need to be assessed to determine whether the results are applicable to other areas and geological conditions.

The Board concludes that the risks to SAGD bitumen production increase at lower operating pressures. As a result, the Board continues to believe that where gas is associated with bitumen, gas zone depressuring should be minimized to better ensure successful SAGD operations in terms of resource recovery and minimizing the technical difficulty of lifting SAGD fluids. Furthermore, in the absence of field data, the Board continues to believe that the minimum steam chamber pressure required for artificial lift to be technically feasible would be in the range of 400 to 600 kPaa, as stated in *Decision 2000-22*.

In addition to society's immediate needs, the Board believes that it should consider the longer-term aspects of resource development and the longer-term interests of future Albertans. Therefore, given the number of unknowns about the technical and economic parameters surrounding SAGD bitumen recovery, the Board believes that it has a responsibility to ensure that long-term bitumen recovery is not jeopardized by the production of gas that is in pressure communication with significant bitumen resources.

The Board continues to believe that the current gas production application process, as per *ID 99-1*, is appropriate to ensure that potentially at risk bitumen is not jeopardized. However, the Board believes that there is a need to address grandfathered gas production[3] in the Athabasca Wabiskaw-McMurray deposit, including the Chard-Leismer area. With respect to the existing

[3] "Grandfathered gas production" refers to production from wells completed in the defined oil sands strata prior to July 1, 1998.

requirements and regulations pertaining to drilling density and the collection and submission of pressure, core, and seismic data, the Board does not believe that any changes are currently practical or necessary. Furthermore, the Board encourages parties to undertake a process planning exercise with the assistance of a neutral third party to evaluate the merits of the various alternative dispute resolution options that may be available.

Having considered all the evidence, the Board concludes that gas production from certain perforated intervals within the Wabiskaw-McMurray presents a high risk to future bitumen recovery in the Chard-Leismer area, but a low risk from other perforated intervals. Accordingly, the Board has made the following decisions with respect to the wells included in the applications that were considered at the subject hearing:

- The Board will order the shut-in of associated gas production effective May 1, 2003, from specific perforated intervals within the Wabiskaw-McMurray in 39 wells.

- The Board denies associated gas production from specific perforated intervals within the Wabiskaw-McMurray in 21 wells.

- The Board approves gas production from specific perforated intervals within the Wabiskaw-McMurray in 21 wells.

- The Board will not require the shut-in of gas production from specific perforated intervals within the Wabiskaw-McMurray in 76 wells.

- The Board will not order the implementation of a pressure-monitoring program in the Chard-Leismer area.

The above decisions result in several considerations and requirements. In particular, with respect to Wabiskaw-McMurray grandfathered gas production and previously approved Wabiskaw-McMurray gas production in the Chard-Leismer area from wells not specifically considered at the subject hearing, the Board believes that some of the gas being produced by these 139 wells could present a significant risk to future bitumen recovery. The Board also believes that some grandfathered gas production in other areas of the Athabasca Wabiskaw-McMurray deposit with a depositional environment similar to that at Chard-Leismer (i.e., fluvial-estuarine) could present a significant risk to future bitumen recovery. Therefore, the Board believes that there is a need to develop and implement a process to address grandfathered gas production in the Athabasca Wabiskaw-McMurray deposit (including Chard-Leismer), and it intends to pursue this matter.

ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

CHARD AREA AND LEISMER FIELD
ATHABASCA OIL SANDS AREA **Decision 2003-023**

Applications for Approval to Produce Gas
Devon Canada Corporation: 1058461, 1066525, 1066527, 1068637, 1071817, 1072845, 1072848, 1097088, and 1097089
EnCana Corporation: 1062688, 1088067, and 1091687
BP Canada Energy Company: 1085736, 1092171, 1093063, and 1096254
Paramount Resources Limited: 1089982, 1090265, and 1091676
Rio Alto Exploration Ltd.: 1090128 and 1090454

Application for Section 40 Review of Applications No. 1069381 and 1069382 for Approval to Produce Gas
Devon Canada Corporation: 1078980

Application for Section 39 Review of Applications No. 1039410 and 1047055 for Approval to Produce Gas
Newmont Mining Corporation of Canada Limited: 1086353

Application for Shut-in of Gas Production
Petro-Canada Oil and Gas: 1085793

Proceeding and Application Respecting Potential Impact of Gas Production on Bitumen Recovery
Devon Canada Corporation: 1073875
Alberta Energy and Utilities Board Staff Submission Group: 1097090

1 DECISION

Having considered all the evidence, the Alberta Energy and Utilities Board (EUB/Board) concludes that gas production from certain perforated intervals within the Wabiskaw Member of the Clearwater Formation and McMurray Formation (Wabiskaw-McMurray) presents a high risk to future bitumen recovery in the Chard area and Leismer Field (Chard-Leismer), but a low risk from other perforated intervals. Accordingly, the Board has made the following decisions with respect to the wells included in the applications that were considered at the subject hearing.

- The Board will order the shut-in of associated gas production effective May 1, 2003, from specific perforated intervals within the Wabiskaw-McMurray in 39 wells listed in Appendix 1. An order requiring the shut-in of gas production will be issued shortly that supersedes any previously issued orders respecting commingled production from these specific perforated intervals in the subject wells.
- The Board denies associated gas production from specific perforated intervals within the

Wabiskaw-McMurray in 21 wells listed in Appendix 1.

- The Board approves gas production from specific perforated intervals within the Wabiskaw-McMurray in 21 wells listed in Appendix 1.

- The Board will not require the shut-in of gas production from specific perforated intervals within the Wabiskaw-McMurray in 76 wells listed in Appendix 1.

- The Board will not order the implementation of a pressure-monitoring program in the Chard-Leismer area.

The above decisions result in the following considerations and requirements:

1) The Board recognizes that some unusual circumstances may arise as a result of the above decisions, and therefore, it may be appropriate for the Board to grant relief from some of its regulatory requirements. For example, there are requirements related to the suspension and abandonment of wells, pipelines, and other field facilities and requirements pertaining to long-term inactive wells that can trigger liability management considerations. Therefore, the Board is prepared to consider requests for relief from such requirements.

2) In multizone wells where only certain zones are permitted to produce gas, zonal segregation tests shall be conducted and submitted to the EUB in accordance with Section 11.150(1) and (2) of the Oil and Gas Conservation Regulations (OGCR) to confirm that segregation has been established between zones that are permitted to produce gas and zones that are not permitted to produce gas. In circumstances where segregation between zones cannot be established, the Board directs that all affected zones be shut in.

3) The Board will require Petro-Canada Oil and Gas (Petro-Canada), Newmont Mining Corporation of Canada Limited (Newmont), EnCana Corporation (EnCana), and Nexen Canada Ltd. (Nexen) each to submit an annual report on the management of the resources on its oil sands leases in the Chard-Leismer area, including an assessment of the effect that the pressure of the overlying gas zone has on the recovery of bitumen by steam-assisted gravity drainage (SAGD). The reporting period, filing date, and content of the reports shall be as outlined in Appendix 2, which is similar to that currently required of Conoco Canada Resources Limited (Conoco) for its Surmont oil sands leases. Furthermore, although the Board will not mandate a pressure-monitoring program in the Chard-Leismer area, it encourages gas and bitumen owners to cooperatively develop and implement a program acceptable to all parties. If requested, the Board would be prepared to work with interested parties in this regard.

4) With respect to Wabiskaw-McMurray grandfathered gas production[1] and previously approved Wabiskaw-McMurray gas production in the Chard-Leismer area from wells not specifically considered at the subject hearing, the Board believes that some of the gas being produced by these 139 wells, shown in Appendix 3, could present a significant risk to future

[1] "Grandfathered gas production" refers to production from wells completed in the defined oil sands strata prior to July 1, 1998.

bitumen recovery. The Board also believes that some grandfathered gas production in other areas of the Athabasca Wabiskaw-McMurray deposit with a depositional environment similar to that at Chard-Leismer (i.e., fluvial-estuarine) could present a significant risk to future bitumen recovery. Therefore, the Board believes that there is a need to develop and implement a process to address grandfathered gas production in the Athabasca Wabiskaw-McMurray deposit (including Chard-Leismer), and it intends to pursue this matter.

2 INTRODUCTION

2.1 Applications

This decision report deals with 26 applications from various parties that involve production or shut-in of gas from the Wabiskaw-McMurray in the Chard-Leismer area within the Athabasca oil sands area. The Chard-Leismer area is located adjacent to the Conoco Surmont oil sands leases, as shown in Figure 1, where, as a result of *Decision 2000-22,*[2] the Board ordered the shut-in of associated gas production from 146 wells. The subject applications include a total of 129 wells, which are shown in Figure 2 and listed in Appendix 4 (Petro-Canada Chard area application wells) and Appendix 5 (Leismer Field application wells). Also shown in Figure 2 and listed in Appendix 6 are 16 wells that PanCanadian Energy Corporation (PanCanadian), now EnCana, applied to be shut in. EnCana subsequently withdrew the application prior to the conclusion of the hearing (see Section 2.7). Oil sands leases in the Chard-Leismer area are shown in Figure 3.

In general, the parties that applied for approval to produce gas submitted that gas production from the applied-for wells would not have a detrimental impact on future bitumen recovery, whereas the parties that applied for gas shut-in submitted that gas production from the applied-for wells would have a detrimental impact on future bitumen recovery. Following is a summary of the applications.

Applications No. 1058461, 1066525, 1066527, 1068637, 1071817, 1072845, 1072848, 1097088, and 1097089 by Devon Canada Corporation (Devon), formerly Anderson Exploration Ltd. (Anderson), pursuant to Section 3(4) of the Oil Sands Conservation Regulations (OSCR), for approval to produce gas from a total of 11 wells: Devon subsequently withdrew Application No. 1097089, for approval to produce gas from one well, at the hearing.

Applications No. 1062688, 1088067, and 1091687 by EnCana, formerly AEC Oil & Gas (AEC), pursuant to Section 3(4) of the OSCR, for approval to produce gas from a total of 8 wells.

Applications No. 1085736, 1092171, 1093063, and 1096254 by BP Canada Energy Company (BP Canada), pursuant to Section 3(4) of the OSCR, for approval to produce gas from a total of 8 wells.

Applications No. 1089982, 1090265, and 1091676 by Paramount Resources Limited

[2] EUB *Decision 2000-22: Gulf Canada Resources Limited, Request for the Shut-in of Associated Gas, Surmont Area,* March 2000.

(Paramount), pursuant to Section 3(4) of the OSCR, for approval to produce gas from a total of 4 wells.

Applications No. 1090128 and 1090454 by Rio Alto Exploration Ltd. (Rio Alto), pursuant to Section 3(4) of the OSCR, for approval to produce gas from a total of 10 wells.

Application No. 1078980 by Devon, pursuant to Section 40 of the Energy Resources Conservation Act (ERCA), for a review of Applications No. 1069381 and 1069382 by Devon: These two applications for approval to produce gas from a total of 2 wells were previously denied by the EUB. Devon submitted that the Board should review its prior decision and approve gas production from these wells.

Application No. 1086353 by Newmont, formerly Franco-Nevada Mining Corporation Limited (Franco-Nevada), pursuant to Section 39 of the ERCA, for a review of Applications No. 1039410 and 1047055 by Devon: These two applications for approval to produce gas from a total of 2 wells were previously approved by the EUB. Newmont submitted that the Board should review its prior decision and shut in gas production from these wells.

Application No. 1085793 by Petro-Canada, pursuant to Section 3(5) of the OSCR, for the following disposition of 83 wells (see Appendix 4) in the area of its Chard oil sands leases:

- Group 1—The shut-in of all gas production from 24 wells and pressure monitoring in specific zones from some of these wells.

- Group 2—The shut-in of gas production from specific gas zones in 16 wells and/or pressure monitoring in specific zones from some of these wells, and the rescission of commingled production approvals.

- Group 3—The shut-in of gas production from 26 wells if pressure monitoring of Group 1 and 2 wells reasonably demonstrates that pressure communication is occurring.

- Group 4—The continued suspension or shut-in of gas production from 17 wells.

Petro-Canada further requested that 58 gas wells shut in as a result of *Decision 2000-22* remain shut in and that in the absence of a pressure-monitoring program to ensure that pressure communication is not occurring, all Group 1, 2, and 3 wells be shut in.

Proceeding No. 1073875, pursuant to Section 3(5) of the OSCR, to review the potential impact of continued gas production on bitumen recovery from the Devon 00/10-22-77-6W4/0 well: This proceeding was initiated by the EUB as the result of the Board denying an application for approval to produce gas from a well interpreted to be in the same gas pool as the Devon well.

Application No. 1097090 by the EUB Staff Submission Group (SSG), pursuant to Section 3(5) of the OSCR, for specific directives regarding grandfathered gas production in the Leismer Field: The SSG submitted that if any of the applied-for gas production in the Leismer Field is not approved, the Board should consider taking the following actions:

- shut in any grandfathered gas production within the region of influence of the wells for which gas production was denied;

- shut in other grandfathered gas wells in the Leismer Field that are producing from a fluvial-estuarine environment; and

- decide on a process for dealing with grandfathered wells elsewhere in the Athabasca Wabiskaw-McMurray deposit that are producing from a fluvial-estuarine environment.

2.2 Interventions

The EUB received a number of interventions regarding the above applications. Because many of the companies that filed applications also had an interest in applications filed by other parties or grandfathered gas wells in the Leismer Field, interventions were also filed by most of these companies. In general, the parties that filed interventions to applications for approval to produce gas submitted that gas production from some or all of the applied-for wells would have a detrimental impact on future bitumen recovery, whereas most of the parties that filed interventions to applications for the shut-in of gas submitted that gas production from the applied-for wells would not have a detrimental impact on future bitumen recovery. Following is a summary of the interventions:

- Newmont filed interventions to Applications No. 1058461, 1072845, 1072848, and 1097089.

- PanCanadian filed interventions to Applications No. 1058461, 1066525, 1066527, 1068637, 1071817, 1072848, 1073875, 1078980, 1085736, 1086353, and 1096254. EnCana subsequently withdrew these interventions (see Section 2.7).

- Nexen filed interventions to Applications No. 1066525, 1066527, 1068637, 1078980, 1085736, 1086353, 1093063, 1096254, 1097088, and 1097089.

- Koch Petroleum Canada (Koch) filed interventions to Applications No. 1085736 and 1096254 and Proceeding No. 1073875. Koch subsequently decided to not participate in the hearing but requested that the submissions it had filed remain on the hearing record.

- Petro-Canada filed interventions to Applications No. 1090128, 1090454, and 1091676.

- The Chard Gas Producers (CGP) filed an intervention to Application No. 1085793. The CGP includes Calpine Canada Natural Gas Company (Calpine), Canadian Forest Oil Ltd. (Canadian Forest), Paramount, and Rio Alto. These companies operate or have a working interest in 38 of the Group 1 and Group 2 wells that Petro-Canada requested to be shut in.

- Northstar Energy Corporation (Northstar), now Devon, filed an intervention to Application No. 1085793. Devon operates 11 of the Group 1 and Group 2 wells that Petro-Canada requested to be shut in.
- AEC filed interventions to Applications No. 1085793 and 1097090. AEC is the licensee for one of the Group 2 wells that Petro-Canada requested to be shut in.

- Conoco filed interventions in support of Applications No. 1085793 and 1097090 but did not actively participate in the hearing.

- Japan Canada Oil Sands Limited (Jacos) filed an intervention in support of Application No. 1085793. Jacos is a joint interest holder with Petro-Canada in the Chard oil sands leases. Jacos subsequently withdrew its intervention and did not participate in the hearing.

- Devon filed interventions to Applications No. 1086353 and 1097090 and Proceeding No. 1073875. It submitted that the SSG's proposed blanket shut-in of grandfathered gas production is neither necessary nor warranted in the absence of a well-founded objection by an oil sands leaseholder.

- BP Canada filed an intervention to Application No. 1097090. It submitted that the Board should reject the SSG's proposal for a blanket approach to precluding gas production or the shut-in of gas production in oil sands areas.

- Paramount filed an intervention to Application No. 1097090. It submitted that the Board should reject the findings and recommendations of the SSG.

- Seaton-Jordan & Associates Ltd. (Seaton-Jordan), an oil and gas-consulting firm, filed an intervention. Seaton-Jordan submitted that the shutting in of gas production would not be in the public interest.

- Alta Gas Services Inc. (Alta Gas) filed an intervention but did not actively participate in the hearing.

2.3 Preliminary Meeting

On March 27, 2001, the EUB held a public meeting regarding 13 applications received from several companies involving the production or shut-in of gas from the Wabiskaw-McMurray in the Chard-Leismer area. The purpose of the meeting was to obtain input from interested parties regarding

- the process that should be used for the review of the applications, including the possibility of all the applications being dealt with in a common proceeding;

- the need for a process to review the appropriateness of continued Wabiskaw-McMurray gas production in the Leismer Field from other wells not included in the subject applications;

- the issues that need to be considered, such as
  - geological interpretation,
  - economics of developing the bitumen resource,
  - impact of gas production on bitumen recovery,
  - grandfathered gas production in an area with no oil sands leaseholder,

- grandfathered gas production in an area with an oil sands leaseholder but about which no concerns have been raised, and
- potential policy implications beyond the Leismer Field regarding grandfathered gas production;

- whether any of the subject matter for any hearings could be handled in prehearing technical meetings, and if so, to what extent;

- the appropriate time frame for submitting information and conducting a review of the issues; and

- any other relevant matters.

On the basis of the information provided at the meeting and the submissions received, the Board issued a letter on April 26, 2001 (Appendix 7) advising parties of its decision to proceed with a common hearing on specific gas production and shut-in applications and the review of existing gas production in the Leismer Field. The Board further decided that any additional applications to produce gas in the Chard-Leismer area submitted by July 3, 2001, would be included in the hearing and that after that time, the processing of all applications received by the Board to produce gas in this area would be held in abeyance pending the issuance of the Board's decision regarding the hearing. With respect to the matter of shutting in gas production pending the outcome of the hearing, the Board decided that it was not prepared to make such a decision in advance of considering all the evidence at the hearing scheduled to commence on November 13, 2001.

2.4 Applications for Review of Decision to Convene a Common Hearing

Subsequent to the Board's April 26, 2001, letter, Anderson, BP Canada, AEC, Paramount, and Petro-Canada applied, pursuant to Sections 39 and/or 40 of the ERCA, for a review and variance of the Board's decision to convene a common hearing with respect to procedural and other matters. The Board subsequently issued a letter (Appendix 8) advising of its decision to deny these applications. This letter included a summary of the issues raised by the companies in support of a review and the Board's comments on each of these issues.

2.5 Interim Hearings and Decisions

2.5.1 Petro-Canada Interim Shut-in Application

On May 25, 2001, Petro-Canada applied, pursuant to Sections 39 and 40 of the ERCA, for the interim shut-in of Wabiskaw-McMurray gas production from 40 wells in the Chard area (Application No. 1094706), pending the Board's final decision from the main hearing scheduled to commence on November 13, 2001. Petro-Canada submitted that the Board erred in its April 26, 2001, decision to not shut in gas production pending the outcome of the main hearing, because the energy statutes require the Board to fulfill its conservation mandate on an interim as well as on a permanent basis. Petro-Canada further submitted that the Board's decision was subject to a review since the Board did not hold a hearing prior to making its decision.

The Board subsequently received a submission from the CGP dated June 4, 2001, and a submission from Northstar dated June 4, 2001. Both the CGP and Northstar opposed Petro-Canada's request for a review or hearing of its application for the interim shut-in of gas production in the Chard area, submitting that the matter could only be properly considered at the main hearing. The CGP further submitted that the Board did not have the jurisdiction to grant an interim shut-in order of the nature sought by Petro-Canada. It argued that the Board's decision to not shut in gas pending the outcome of the main hearing was an interlocutory decision and, therefore, Section 40 of the ERCA could not be used in this context.

On June 5, 2001, the Board issued its decision to conduct a hearing to consider Petro-Canada's application for the interim shut-in of gas production from 40 wells in the Chard area. A public hearing of Application No. 1094706 was held from July 3 to 5, 2001.

On August 2, 2001, the Board issued *Decision 2001-63*[3] (Appendix 9). The Board concluded that pending the outcome of the main hearing, continued production of associated gas from certain zones in 10 wells might present a significant risk to future bitumen recovery and might result in associated economic losses in portions of the Chard area. Accordingly, the Board granted Petro-Canada's application in part and ordered the interim shut-in of associated gas production effective September 1, 2001, from specific perforated intervals in the 10 wells. The wells were to remain shut in pending the Board's final decision regarding Application No. 1085793.

2.5.2 Franco-Nevada Interim Shut-in Application

On March 20, 2001, Franco-Nevada requested that the Board shut in gas production from the 00/10-23-76-7W4M/0 (10-23) well on an interim basis, pending the Board's ultimate disposition of related applications by Anderson for approval to produce gas in the area of Franco-Nevada's oil sands lease. On April 26, 2001, the Board denied Franco-Nevada's application for the interim shut-in of the 10-23 well.

On June 5, 2001, Franco-Nevada filed an application (Application No. 1095081) requesting that the Board review at a hearing its April 26, 2001, decision in which it denied Franco-Nevada's application for the interim shut-in of the 10-23 well. The Board subsequently received a submission from Anderson dated June 8, 2001, opposing Franco-Nevada's request for a hearing. Anderson submitted that Franco-Nevada had not provided any new evidence that would justify the reversal of the Board's earlier decision.

On June 12, 2001, the Board issued its decision to conduct a hearing to consider Franco-Nevada's application for the interim shut-in of the 10-23 well. A public hearing of Application No. 1095081 was held on July 9 and 10, 2001.

[3] EUB *Decision 2001-63: Petro-Canada Oil and Gas, Interim Shut-in of Gas Production, Chard Area,* August 2, 2001.

On August 2, 2001, the Board issued *Decision 2001-64*[4] (Appendix 10). The Board was not persuaded that continued gas production from the 10-23 well in the interim period to the main hearing would have a significant impact on bitumen recovery, the costs of recovering the bitumen, and the economic desirability of a bitumen project. Accordingly, the Board denied Franco-Nevada's application.

2.6 Rescheduling of Hearing

On November 5, 2001, the Board received a letter from the CGP requesting an adjournment and restructuring of the hearing process to provide sufficient time to review and analyze the rebuttal evidence filed by Petro-Canada on October 30, 2001. After considering submissions from a number of interested parties regarding the CGP's request, the Board agreed that an adjournment was warranted and the hearing was rescheduled to commence on November 26, 2001.

2.7 Hearing

A public hearing of the subject applications began on November 26, 2001, in Calgary, Alberta, before Board Member J. D. Dilay, P.Eng., and Acting Board Members C. A. Langlo, P.Geol., and W. J. Schnitzler, P.Eng. The hearing was segmented into three parts:

- Part one: evidence related to Petro-Canada's application to shut in gas in the Chard area;
- Part two: evidence related to applications to produce gas and existing gas production in the Leismer Field; and
- Part three: closing arguments.

The evidentiary portion of the hearing (i.e., parts one and two) concluded on May 22, 2002, and involved 66 sitting days, over 800 exhibits, and about 12 000 pages of transcript. Closing arguments (i.e., part three) were presented in written form and in accordance with an outline issued by the Board on May 16, 2002 (Appendix 11). Final argument and reply argument were submitted on June 14 and 28, 2002, respectively. A list of the hearing participants is provided in Appendix 12.

On February 4, 2002, PanCanadian applied, pursuant to Section 3(5) of the OSCR, for the shut-in of gas production from 16 wells in the Christina Lake area (Application No. 1256085). PanCanadian submitted that there were significant bitumen resources on its Christina Lake oil sands leases and that the recovery of these resources would be adversely affected by continued gas production from these wells. PanCanadian further requested the immediate shut-in of 14 of the 16 wells, since the pressures of these wells were at or approaching depletion levels such that, in the absence of immediate shut-in, a sizable bitumen resource would be sterilized. PanCanadian subsequently requested that its shut-in application be heard as part of the current hearing due to the urgent need for a process to deal with the application.

On February 8, 2002, immediately following AEC's evidence in chief, Petro-Canada submitted that a significant portion of AEC's testimony was new. As a result, Petro-Canada requested that either AEC's testimony be struck from the record or other parties be given an opportunity to

[4] EUB *Decision 2001-64: Franco-Nevada Mining Corporation, Interim Shut-in of Gas Production, 00/10-23-076-07W4M/0 Well, Leismer Field,* August 2, 2001.

obtain and review the information that supported the material presented prior to cross-examination of the AEC witness panel.

On February 11, 2002, the Board heard submissions from the hearing participants on PanCanadian's shut-in application and AEC's evidence in chief. On February 12, 2002, the Board advised the hearing participants of its decisions. With respect to PanCanadian's shut-in application, the Board decided to incorporate the application into the current hearing. With respect to AEC's evidence in chief, the Board decided that although some of the evidence was new, it should not be struck from the record. To provide parties with an opportunity to review and respond to this new material, the Board adjourned the hearing until March 12, 2002.

During the course of the hearing, PanCanadian and AEC merged to form EnCana. Given that PanCanadian and AEC had submitted evidence and positions that were different and competing with respect to some issues, the Board requested that EnCana clarify its position on these issues. On May 14, 2002, EnCana requested leave to withdraw PanCanadian's interventions (see Section 2.2) and its application to shut in gas production in the Christina Lake area (Application No. 1256085). EnCana submitted that the withdrawal of the PanCanadian interventions and application would have the effect of automatically expunging all evidence given in support of the interventions and application. On May 22, 2002, after hearing submissions from the hearing participants on this matter, the Board granted EnCana's request to withdraw PanCanadian's interventions and application, but decided that the PanCanadian evidence would not be expunged from the hearing record.

During the hearing, Nexen raised the issue that six grandfathered wells not included in any of the shut-in applications were in the same region of influence as some of the application wells. BP Canada, which had an interest in some of the wells, argued that the case made by Nexen was new and that BP Canada had not been provided with reasonable notice or opportunity to assess, test, and prepare evidence in response to Nexen's case. The Board ruled that it would not consider the shut-in of the six wells as a result of this hearing and further stated that if the Board's review of the evidence indicated that continued gas production from these wells might be a problem for bitumen recovery, it would provide the parties with some other basis on which to deal with the wells.

3 ISSUES

The Board considers the issues with respect to the subject hearing to be as follows:

- extent of affected resources/reserves,
- reservoir and aquifer continuity,
- effect of associated gas production on SAGD bitumen recovery,
- geomechanical effects,
- feasibility of artificial repressuring,
- feasibility of artificial lift,
- economics,
- individual applications,
- regulatory process, and
- other matters.

This report does not contain a summary of the hearing participants' views, as is the Board's normal practice. Instead, the written closing arguments of the parties, along with this decision, have been attached in electronic format (see computer disk at the end of the report). Following are the views of the Board with respect to the above issues.

4 EXTENT OF AFFECTED RESOURCES/RESERVES

4.1 Remaining Recoverable Gas Reserves

The Board notes that the CGP took no issue with Petro-Canada's estimate of the remaining recoverable gas reserves for the gas wells and zones requested to be shut in at Chard. Furthermore, the Board notes that although several of the hearing participants provided estimates of remaining recoverable gas reserves for their own lands in the Leismer Field, the SSG was the only party that provided an estimate for the entire Leismer Field. Therefore, on the basis of the evidence submitted, the Board concludes that the remaining recoverable gas reserves potentially affected by Petro-Canada's shut-in application are 426 million cubic metres (10^6 m^3) as of January 1, 2001, and that the remaining recoverable gas reserves in the Leismer Field are in the order of 1500 10^6 m^3 as of July 3, 2001. However, the Board acknowledges that the potential exists for some additional gas reserves to be discovered in the Chard-Leismer area.

4.2 Bitumen Resources/Reserves

The Board shares Nexen's and the SSG's view that the Wabiskaw-McMurray bitumen resources in the Chard-Leismer area are on trend with Alberta's most significant bitumen deposits. The Board also notes that most announced and approved commercial SAGD projects fall within this trend. The Board further agrees with Nexen that given the geological complexity of the McMurray Formation, a regional geological picture should be used as a starting point to assess the bitumen resource. The regional geological information provided at the hearing indicates to the Board that the higher quality and quantity of potentially recoverable bitumen are generally associated with fluvial-estuarine channels within the Wabiskaw-McMurray.

The Board notes that the SSG provided a bitumen-in-place estimate and map for the entire Leismer Field, while a number of companies provided bitumen-in-place estimates and mapping for portions of the Chard-Leismer area. The Board agrees with the SSG that its map only provides a regional perspective of the magnitude of the bitumen resource in the Leismer Field, and it also agrees with EnCana that the bitumen resource estimates provided by various companies cannot be simply summed together to provide a complete resource estimate given the different criteria used by the parties. Furthermore, the Board notes that not all parts of Chard-Leismer were mapped. The Board believes, however, that the bitumen-in-place estimates and mapping provided indicate the existence of a significant amount of potentially recoverable bitumen in the Chard-Leismer area, which warrants consideration for protection for future development. Although no bitumen reserves have been publicly booked in the Chard-Leismer area and only one commercial project is under way, the Board does not believe that this precludes further development of some of the bitumen resources in the area using present or reasonably foreseeable technology. Furthermore, as pointed out by the SSG, if even a small portion of the bitumen resource at Leismer is recoverable, the energy value of this bitumen would far exceed the total energy equivalent of the remaining recoverable gas reserves in the Leismer Field.

Although substantial quantities of bitumen exist in the hearing area, the Board agrees with the general consensus of the hearing participants that only the bitumen that meets certain basic cutoffs and parameters should be considered as being worthy of protection. Furthermore, the Board shares EnCana's view that minimum bitumen cutoffs cannot be used exclusively in assessing the commercial viability of a bitumen prospect, since depositional factors (e.g., top gas/water or basal water) may also affect the economic production of a specific bitumen resource. However, the Board does not accept the view expressed by several hearing participants that commercial criteria should be applied at the stage when a bitumen resource is being prospected and delineated. To do so could result in a significant bitumen resource being inappropriately designated as unworthy of protection prior to being properly assessed. This is particularly true given the relatively low drilling density over most of the Chard-Leismer area.

The Board notes that the bitumen pay criteria submitted by the hearing participants vary significantly and that none of the parties submitted any studies to support the technical or economic basis for their proposed criteria. This suggests to the Board that there is insufficient understanding of the capabilities and limitations of SAGD at this time to definitively establish a bitumen pay criteria. Therefore, until more information becomes available, the Board believes that it should continue to use the criteria outlined in *Interim Directive (ID) 99-1*[1] (i.e., 10 m or more of sand with bitumen saturation equal to or greater than 50 per cent pore volume for the Wabiskaw-McMurray).

5 RESERVOIR AND AQUIFER CONTINUITY

5.1 Regional-Scale Hydrogeology and Aquifer Systems

5.1.1 Hydrogeologic and Hydrodynamic Models and Studies

The Board heard evidence regarding the nature and importance of regional groundwater flow in determining regions of influence. The Board sees no reason to move away from its definition of a region of influence, as set out in *ID 99-1,* or from its understanding of the regional hydrogeology of the Athabasca Oil Sands Area (including Chard-Leismer), as discussed in *Decision 2000-22*. The Board believes that the theory of hydraulic continuity is fundamental to interpreting subsurface hydrogeological data at a regional scale and to the interpretation of regions of influence at a smaller scale. The Board notes that this position is in general agreement with the submissions of Nexen, Newmont, and Petro-Canada.

The Board heard competing views on the origin of regionally pervasive subhydrostatic pore pressures (i.e., underpressures) in the McMurray. The Board finds the presence of underpressures in Chard-Leismer consistent with the existence of the regional gravity-driven groundwater flow system discussed in *Decision 2000-22*. In that instance, the Board accepted the

[1] EUB *Interim Directive (ID) 99-1: Gas/Bitumen Production in Oil Sands Areas – Application, Notification, and Drilling Requirements*, February 3, 1999.

existence of a regional gravity-driven flow system that encompasses both the Chard-Leismer and Surmont areas. Since this flow system encounters McMurray outcrops along the Athabasca River at elevations lower than the measured hydraulic heads in the upper McMurray aquifer at Chard-Leismer, the Board believes that underpressures observed in the Chard-Leismer area are a consequence of regional gravity-driven groundwater flow.

Petro-Canada submitted potentiometric surface maps for the upper McMurray aquifer at Chard. It argued that lenticular patterns of widely spaced hydraulic head contours on the maps are areas of high transmissivity in the upper McMurray aquifer and that these areas, termed Regions of Hydraulic Continuity (ROHC), are particularly sensitive to lateral transmission of pore-pressure disturbances due to gas production. Petro-Canada submitted that ROHC should be used as minimum regions of influence. The Board believes that if data of sufficient quantity and quality existed, potentiometric surface analysis could be used to better map regions of influence in accordance with *ID 99-1*. However, the Board believes that it is unlikely there will ever be sufficient high-quality hydraulic head data from the upper McMurray aquifer to confidently map the high-transmissivity lenses in the kind of detail presented by Petro-Canada. Moreover, the Board believes that augmenting the limited high-quality hydraulic head data at Chard with hydraulic head estimates from nontraditional data sources reduces the reliability of the potentiometric mapping technique. The Board also finds that the potentiometric maps provide no information on rates of lateral pressure transmission in the ROHC and thus cannot be used to define minimum regions of influence in engineering time scales. In addition, no geological mapping of sand quality or sand thickness in the upper McMurray aquifer was provided to the Board to independently support the inferred distribution of high-transmissivity lenses. The Board therefore rejects Petro-Canada's argument that ROHC can be used to define minimum regions of influence at Chard.

5.1.2 Gas Pool Pressure Equalization and Equilibration

The Board heard evidence from both bitumen and gas producers concerning gas pool pressure equalization and equilibration. Petro-Canada defined pressure equalization as the process by which gas pressures at different points within a single pool become equal following shut-in, and gas-pool pressure equilibration as the process by which the pools return to pressures determined by regional groundwater flow patterns. The Board believes that the substantive issue underlying this topic is how parties interpret complex shut-in gas pool pressure behaviour, particularly in terms of what the observed behaviours indicate about regional aquifer continuity and lateral pressure transmission.

Since the pore pressure in a static gas pool must equal the pore pressure in the groundwater at the gas-water interface (neglecting pore-scale effects), and since the pressure in the groundwater is systematically changing with depth and position due to groundwater motion, the Board accepts that the virgin pressures in the gas pools are systematically controlled by the geometry of the groundwater flow system. Gas pool pressures will be unequal except by virtue of being located on an iso-pressure line whose geometry is dictated by flow-system configuration. During gas production, the physical laws of continuity of pressure across the gas-water interface must still be obeyed. Consequently as gas pressures decline, pressures in adjoining groundwater must also decline, resulting in groundwater flow into the area of gas production above what is delivered by natural flow under virgin conditions. Over time, this inflow will cause pressures in the remnant gas deposit to rise. In the end, the groundwater flow system will more or less re-establish itself in the vicinity of the produced gas pool and the remnant gas pressure will approach virgin pressures.

The Board agrees with Petro-Canada and Nexen that both pressure redistribution processes will ultimately occur in all produced gas pools across Chard-Leismer over time. However, the Board notes that none of the parties quantified the time necessary for equilibration to occur, except in a generic sense, as discussed in Section 5.1.3. If the equilibration occurs on the scale of geological time, then the observed pressure response would be dominated by equalization and shut-in gas pools would appear to behave like tanks. If the equilibration time is short compared to production time, then equilibration effects such as nonlinear p/z plots and water influx would be clearly observable in field data. The Board believes that the equilibration time for shut-in pools at Chard-Leismer will likely be influenced by the nature and extent of porosity and permeability within and between reservoir units and thus will be site specific. Therefore, the Board believes that no conclusions regarding regional aquifer continuity or lateral pressure transmission in general can be made from observations of pressure behaviour in any single part of Chard-Leismer.

5.1.3 Gas Pools and Aquifer Simulation Models

Gas pools and aquifer simulation models were provided by Petro-Canada and Newmont. The models submitted by Petro-Canada included the same model that was submitted to the Surmont hearing and a modified model in which two gas pools were produced and then shut in, and the volume of the underlying aquifer was increased at the edges of the model. The Board previously commented on Petro-Canada's model in *Decision 2000-22* that it believed the simulations were generic and indicative only of the direction of pressure transmission and fluid movement, but that they did not cover the full spectrum of possible scenarios. Therefore, the Board concluded that the simulations were not precise in terms of time, distance, and rate of pressure transmission and the predicted drop in pressure at any given point in time and location. The Board believes these comments are also applicable to the modelling work submitted by Petro-Canada to the Chard-Leismer hearing.

The Board notes the SSG's comment that Petro-Canada's model may provide an explanation for the production behavior of Devon's Group 2 wells (i.e., the 03/10-14-76-7W4/0 and 00/10-23-76-7W4/0 wells). As noted by the SSG, the 00/10-23-76-7W4/0 well has produced 98.5 per cent of Devon's mapped initial gas in-place for the pool, and the well continues to produce with a shallow decline and no signs of watering out. However, as recognized by the SSG, another explanation is that the size of the gas pool encountered by the 00/10-23-76-7W4/0 well is significantly larger than that mapped by Devon. Considering the uncertainty in mapping the size of the gas pool, the Board believes this is a reasonable possibility.

With respect to Newmont's modelling, the Board notes that the model assumes there is widespread communication over a very large area. While the Board interprets the presence of several gas pools and some top water zones in the area modelled by Newmont, it does not interpret the gas pools and top water zones to be as extensive as modelled by Newmont. Based on Newmont's comments that the permeabilities, pressures, and production data used in its model were averages of the actual data, the Board concludes that the model is limited to predicting pressure trends.

5.2 Geology of the Wabiskaw-McMurray at Chard-Leismer

5.2.1 Depositional Models

As with *Decision 2000-22*, the Board believes that the integration of all available geological information (i.e., outcrop, core, logs, modern-day and ancient analogs) is required to develop a depositional model for the Wabiskaw-McMurray in the Chard-Leismer area. A number of the hearing participants used modern-day or ancient analogs to describe the depositional environments of the Wabiskaw-McMurray. The Board believes that, although some aspects of these analogs could be applied, none of them fully addresses the complexity or scale of the Wabiskaw-McMurray.

The Board notes that the parties generally agreed that the sediments of the lower and middle portion of the McMurray were deposited in a fluvial and estuarine environment, and while not agreeing in detail, all interpreted the presence of regional sands and mudstones[2] in the upper part of the McMurray. The Board believes that the sands and mudstones of the Wabiskaw-McMurray were deposited as part of an overall transgressive sequence, changing from a fluvial/fluvial-estuarine environment in the lower part of the McMurray, to a restricted marine-estuarine environment in the upper part of the McMurray, and eventually to a fully marine environment in the Wabiskaw. The Board also believes that there were periods of sea-level drop during this overall transgressive event and that during these periods of lower sea level the previously deposited sediments were eroded.

The Board notes that the major points of disagreement among parties centered on the depositional environment, the extent and correlatability of the sands and mudstones of the upper part of the McMurray, and the nature and degree of channelling that occurred during periods of regression in the overall transgressive event. The Board interprets the sands and mudstones within the upper part of the McMurray as having been deposited over a broad area and being correlatable throughout much of the Chard-Leismer area, but believes that the continuity of these units is limited by erosion due to channelling in many areas. The hearing participants referred to the depositional environments of the upper part of the McMurray by a number of different names: bayfill marine shoreline, marine bayfill, wave-influenced strata, shoreface, estuarine valley-fill, restricted marine, regional flooding surface shale facies assemblage, drowned coastal plain, estuarine bayfill, bayhead deltas, and drowned estuaries. This illustrates both the complexity of the upper part of the McMurray and the significant disagreement of the parties on how the sediments were deposited. The Board concludes that the upper part of the McMurray consists of sands and mudstones that were deposited in a restricted marine-estuarine environment.

The Board finds that the diagram submitted by Nexen, as shown in Figure 4, provides a good summary of the depositional cycles that resulted in the sand and mudstone sequences identified in the upper part of the Wabiskaw-McMurray stratigraphy. The diagram portrays relative sea level as a sinusoidal curve that rises over time. It was during the early part of each cycle, when the relative sea level dropped, that channels formed and channel and valley-fill sands and muds

[2] For the purposes of this report, the Board uses the term “mudstone” to identify the mudstones within the McMurray, the term “mud” when referring to the process of deposition, and the term “shale” to identify the consolidated shales of the Wabiskaw.

were deposited. The Board agrees with Devon that there was a drop in sea level at the end of McMurray time, resulting in localized erosion and channel cutting. The Board believes that following this event, the sea level rose, resulting in the deposition of Wabiskaw valley-fill sediments, followed by flooding and deposition of the fully marine Wabiskaw sands and muds.

5.2.2 Stratigraphic Framework

Most of the hearing participants focused their geological review on individual areas of interest. While Nexen provided mapping over the broadest area, encompassing all of the Leismer Field, it did not map the northern areas of Chard. Figure 5 shows each area for which parties provided detailed geological mapping. In order to understand the Wabiskaw-McMurray stratigraphy and to relate the parties' interpretations, the Board reviewed the well logs and submitted core data for all of the Chard-Leismer area. The Board recognizes the existence of regionally correlatable units within the upper part of the McMurray in the Chard-Leismer area. The cleaning upward nature of these units can be identified on geophysical well logs by an overall upward decrease in natural gamma ray emission over the unit. The Board believes that these cleaning upward units occur in a predictable sequence at a consistent depth below a regional Wabiskaw marker over much of the Chard-Leismer area.

The Board notes that the hearing participants used different terminology and techniques to describe the Wabiskaw-McMurray stratigraphy. While several parties described the lithologic sand and mudstone units, some used transgressive and erosive surfaces, and others combined both of these techniques. The Board has adopted a lithologic description, while also recognizing that certain mudstones were deposited on transgressive or erosive surfaces. The Board refers to the McMurray units in the Chard-Leismer area from the base upward as the McMurray C sand, the McMurray B mudstone, the McMurray B sand, the McMurray A mudstone, and the McMurray A sand, as shown in Figure 6. In some parts of Chard-Leismer, the McMurray B sand can be differentiated into a lower B2 sand and an upper B1 sand. However, based on its examination of logs, the Board is unable to identify a distinctive mudstone within the McMurray B sand that clearly separates the McMurray B1 and B2 units everywhere in the Chard-Leismer area.

The Board agrees with Nexen's conclusion that each of the regional units of the upper part of the McMurray represents a transgressive cycle. The Board also agrees with Nexen's interpretation that after each transgression there was a regression during which channels were cut down into the regional sands and muds. The presence of channels that may originate from the top of any of the McMurray sands further complicates the stratigraphy. Channels that have cut down from the top of the McMurray A sand are referred to as McMurray A channels in this report. Similarly, channels that have cut down from the top of the McMurray B2 or B1 sequences are referred to as McMurray B channels. The Board believes that the McMurray C interval largely comprises channel sediments. The McMurray C interval is present throughout the Chard-Leismer area, with local exceptions at highs on the Paleozoic unconformity surface. The McMurray A, B, and C channels are at times referred to collectively as McMurray channels in this report.

The top of the McMurray is marked by an unconformity on which the Wabiskaw sediments were deposited, referred to as the E10 erosional surface by some parties. Throughout most of the Chard-Leismer area, the basal Wabiskaw unit is the Wabiskaw D shale, which is commonly overlain by the Wabiskaw C sand. However, where the Wabiskaw D shale is absent, the Wabiskaw C sand rests directly on McMurray sediments. In part of the Chard-Leismer area, the Wabiskaw D consists of valley-fill sands and shales that are commonly overlain by the Wabiskaw C sand. In addition to the McMurray channelling events and the Wabiskaw D valley-fill event, the Board interprets that a Wabiskaw channel has cut down from the top of the Wabiskaw C sand into the underlying McMurray sediments in the area of Townships (Twps) 75-7W4 and 76-7W4.

The Board interprets the McMurray A and B mudstones as having been removed by channelling where they are not clearly identifiable on logs or in core. The Board has reviewed the interpretations presented by the hearing participants on maps, logs, and cross-sections with respect to the presence or absence of the McMurray A and B mudstones. A summary of the Board's overall findings as a result of this review are shown in Table 1.

Table 1. Summary of McMurray A and B mudstone interpretations[1]

	Number of wells in which the Board **agrees** with the interpretation of the presence or absence of the McMurray A and B mudstones		Number of wells in which the Board **disagrees** with the interpretation of the presence or absence of the McMurray A and B mudstones	
Hearing Participant	Mudstone A	Mudstone B	Mudstone A	Mudstone B
Petro-Canada	47	45	4	6
Nexen	631	644	59	46
AEC	121	93	30	52
CGP	131	103	4	32
Paramount	250	205	107	111

[1] Not all wells were drilled deep enough to assess the McMurray B mudstone.

In general, the Board concurs with Nexen's interpretation, as shown in Figure 7, of the presence of regional sands and where they have been removed due to channelling. Figure 8 shows the Board's interpretation of where the McMurray A and B mudstones have been removed by channelling, while Figures 9 and 10 compare the Board's and Nexen's interpretations of where channelling has removed the McMurray A and McMurray B mudstones respectively. Based on the Board's interpretation, channelling through both the McMurray A and B mudstones occurs in much of the Chard-Leismer area. In many cases, channels that cut down from the top of the McMurray A sand have eroded into channels that have cut down from the top of the McMurray B sand, such that neither the McMurray A nor the McMurray B mudstones are preserved.

The Board accepts that the Wabiskaw sediments were deposited on an erosional unconformity at the top of the McMurray, identified by Devon as the E10 erosional surface and by the CGP and Paramount as Marker 40. The Board agrees with these parties that this surface is correlative over an extensive area and is often overlain by Wabiskaw D shale. However, the Board interprets the Wabiskaw D shale to be generally thin, varying in thickness from up to 2 m at Chard to being absent in the western part of Leismer.

In some parts of the Chard-Leismer area, Wabiskaw channels have eroded into the top of the McMurray, resulting in the deposition of Wabiskaw channel and valley-fill deposits that are referred to by the Board as Wabiskaw D valley-fill. Although the sands within the Wabiskaw D are indistinguishable on logs or in core from McMurray sands, this unit is identifiable in core by the dark grey, fissile nature of its shales, in contrast to the light grey or tan coloured mudstones in the McMurray. Devon contended that the Wabiskaw valley-fill sediments are characterized by an identifiable and correlatable extensive bay mudstone occurring most often at the base of the valley-fill. It also contended that where present, this basal bay mudstone would act as a seal isolating the Wabiskaw from the underlying McMurray. However, Devon acknowledged that the thickness of the basal bay mudstone is not resolvable on well logs if it is less than 0.5 m thick. The Board reviewed cores that were logged and/or photographed by parties in the area where Devon submitted that the mud-lined Wabiskaw valley was present (i.e., Twp 76-6W4 to Twp 77-7W4). The Board concludes that although mudstones and shales are present in the upper portion of the Wabiskaw-McMurray interval, the mudstones/shales are not correlatable over more than one to two sections before their character (i.e., lithology, thickness, and/or relative stratigraphic position) changes. The Board believes that this change in character indicates a different depositional unit and that the mudstones/shales are discontinuous. To illustrate that even on a very local scale the mudstones/shales are not correlatable, details from a few of the cores and logs reviewed are provided in Table 2.

The transgressive Wabiskaw C sand, which the Board and all the parties recognize as being fully marine, overlies the Wabiskaw D valley-fill and/or Wabiskaw D shale. The Board interprets that a Wabiskaw channel (Wabiskaw C channel) cut down from the top of the Wabiskaw C sand into the underlying McMurray sediments, removing the Wabiskaw C transgressive sand and Wabiskaw D shale in the area of Newmont's oil sands leases. This channel may have locally removed the McMurray A and/or B regional mudstones or may have amalgamated with McMurray channels that had done so.

In summary, the Board concludes that

- regionally correlatable units within the upper part of the McMurray at Chard-Leismer were cut by channels that filled with sand and mud deposits;
- where the McMurray A and B regional mudstones cannot be clearly identified on logs or in core, they were removed by erosion due to channelling;
- the Wabiskaw D valley-fill estuarine mudstone is not correlatable over significant distances;
- the Wabiskaw D shale is correlatable, but not always present, throughout Chard-Leismer; and
- a Wabiskaw C channel, in the area of Newmont's oil sands leases, removed the Wabiskaw C sand and Wabiskaw D shale and may have removed the McMurray A and/or B regional mudstones.

5.2.3 Lateral Continuity of Mudstones and Shales

The Board agrees with Nexen and the SSG that the lateral continuity of mudstones is dependent upon the environment in which they were deposited. The Board interprets four environments in which muds were deposited in the Chard-Leismer area: 1) within abandoned channels; 2) on channel point bars (i.e., inclined heterolithic stratification [IHS]); 3) as mud breccias within channels or on point bars; and 4) as regional muds associated with transgressive events.

The Board believes that muds deposited in a channellized environment during the abandonment phase of a channel (commonly referred to as mud plugs) would have an areally restricted lateral extent, as the muds would have been confined by the size (i.e., length, breadth, and depth) of the

Table 2. Core and log review of Wabiskaw D valley-fill basal bay mudstone

Unique Well ID	Mudstone/shale descriptions and interpretations	Views of the Board
AA/7-9-76-6W4/0 (7-9)	Log (Devon[1]) – occurs 18.2 m below T21 marker from 345.2 to 346.4 mKB (1.2 m thick). Core (Nexen[2]) – described as 1 m thick grey burrowed shale with white silt, and interpreted as basal mudstone of McMurray A shoreface sand.	The Board agrees with Nexen's description of the mudstone and interpretation of the depositional environment. The mudstone grades upward into sands, which is typical of the McMurray A regional sand.
AA/16-9-76-6W4/0 (16-9)	Log (Devon[1]) – occurs 21.3 m below T21 marker from 333.6 to 334.7 mKB (1.1 m thick). Core (Nexen[2]) – described as 0.5 m thick (at top of core) black, fissile shale interbedded with wave-rippled, fine to very fine grained, oil-stained, quartzose sand and light grey silt, lightly burrowed, and interpreted as subtidal flat.	The Board agrees with Nexen's description of the mudstone and interpretation of the depositional environment. Although the mudstone occurs at the same relative stratigraphic position and depth below the Wabiskaw marker as the mudstone at the 7-9 well, this mudstone has a different lithology (i.e., black fissile shale versus grey shale) and, therefore, cannot be continuous between these two closely spaced (i.e., 900 m) wells.
00/5-16-76-6W4/0 (5-16)	Log (Devon[1]) – occurs 44.2 m below T21 marker from 351.0 to 352.0 mKB (1.0 m thick).	The Board interprets this mudstone to be distinct from the mudstone at both the 7-9 and 16-9 wells based on its significantly different stratigraphic position.
AA/9-17-76-6W4/0 (9-17)	Log (Devon[1]) – occurs 19 m below T21 marker from 332.0 to 346.5 mKB (14.5 m thick). Core (Devon[1]) – described as medium grey silty shale, and interpreted as distal subtidal bay. Core (Nexen[3]) – described as finely laminated to massive light grey shale, unburrowed, thin sideritic shale beds, horizontal bedding, and interpreted as abandoned channel fill.	The Board agrees with Nexen's interpretation that the mudstone was deposited in an abandoned channel. The significantly greater thickness of this mudstone compared to the mudstones at the 7-9, 16-9, and 5-16 wells, in addition to the depositional environment, indicates that it is not correlative to the mudstones in these wells.

1 Exhibit No. 119, Volume 2, Appendix A.
2 Exhibit No. 999-14.
3 Exhibit No. 908, Appendix 1.

channel. While a channel freeway may be very large and, as shown in Figure 8, may be townships wide, the individual channels that existed at any one time would have been much narrower. The Board notes that no effective way of delineating channel mud plugs was put forward by any of the hearing participants. Therefore, without significantly increased drilling density, the Board believes that the presence of a channel mud plug merely confirms the existence of channels that may be sand-filled only a short distance away.

The Board believes that muds associated with IHS are not laterally extensive, because the muds are confined to the length and width of the point bar on which they were deposited and are often truncated laterally by later channelling events. The Board also believes that mud breccias are indicative of channel environments and are not laterally extensive.

The Board believes that the McMurray A and B mudstones and Wabiskaw D shale are different in origin and lateral extent from mudstones that are part of a channel. These regional mudstones were deposited over broad areas and have been removed in places through erosion due to channelling.

5.2.4 Similarities and Differences Between Chard-Leismer and Surmont

The Board agrees with the hearing participants that the McMurray and Wabiskaw were deposited as part of a fluvial-estuarine-marine sequence throughout the Chard-Leismer and Surmont areas. The Board also agrees with the observation of the CGP and SSG that IHS is present within the McMurray channel deposits at Chard-Leismer and Surmont. Furthermore, the Board believes that channel sediments of the McMurray C interval extend across the entire Chard-Leismer and Surmont areas, with local exceptions at highs on the Paleozoic unconformity surface.

The Board notes that the hearing participants agreed that regional sands and mudstones of the McMurray are present in parts of the Chard-Leismer area. The Board interprets this as different from the Surmont area, where, as observed by Nexen and Petro-Canada, fluvial-estuarine channels make up the entire McMurray section.

The Board believes that the channels that have removed the McMurray A and B mudstones at Chard-Leismer also extend into Surmont. The regional sands and mudstones of the McMurray are recognized as constituting the interchannel sediments. The Board believes that the presence of interchannel regional mudstones taken in conjunction with the channel abandonment mudstones of the McMurray causes the McMurray at Chard-Leismer to be generally muddier in nature than at Surmont, which is similar to observations of BP Canada, CGP, and Paramount. However, the Board believes that the channel abandonment mudstones, mudstones within IHS intervals, and mudstone breccias are limited in extent and indicate the presence of channels that may be sand-filled a short distance away. Similar to Surmont, the occurrence of thick, sand-filled channels is extensive and randomly distributed in the channel environments at Chard-Leismer.

5.3 Vertical Continuity

5.3.1 Geological Data and Pressure Data from Segregated Gas Zones

As stated in Section 5.2.2, the Board recognizes the existence of regionally correlatable mudstones associated with the McMurray A sand (i.e., McMurray A mudstone) and McMurray B2 sand (i.e., McMurray B mudstone). Although these mudstones are not preserved everywhere in the Chard-Leismer area, the Board agrees with the CGP, AEC, Paramount, Rio Alto, and SSG that, where present, the McMurray A and B mudstones act as barriers to vertical pressure transmission and, therefore, that pressure depletion of gas zones overlying these mudstones should not be transmitted to underlying sediments. This conclusion is based on the areal extent of the McMurray A and B mudstones relative to the size of the overlying gas pools and top water zones, the distribution of reservoir fluids within the sands, and pressure data from segregated gas zones. Based on similar observations, the Board also believes that the Wabiskaw D shale, where present, acts as a barrier to vertical pressure transmission, such that pressure depletion due to production of gas from above the Wabiskaw D shale would not be transmitted to the sands below

the shale.
The Board agrees with the CGP that the McMurray A and B mudstones can be mapped orders of magnitude larger in area than any given overlying McMurray A or B sand gas pool. Logs and core indicate that the McMurray A sand is not present without the associated McMurray A mudstone. Therefore, it follows that the McMurray A mudstone must underlie gas reservoirs contained within McMurray A sand. Similarly, for gas contained within the McMurray B2 sand, the underlying McMurray B mudstone must inherently be present. As such, gas pools contained within the McMurray A and McMurray B2 sands have an underlying regionally correlatable mudstone extending at least to the edge of the gas pool and, more commonly, beyond.

The SSG argued that the absence of regional McMurray mudstones or Wabiskaw shale within a well or within the extent of a gas pool and adjacent sections would result in vertical communication of a gas accumulation with underlying bitumen. Newmont, Nexen, and Petro-Canada similarly argued that where channels have subsequently removed regional mudstones/shales, vertical communication of a gas accumulation with underlying bitumen is likely. The Board agrees that in these circumstances the channel sequence is similar to the depositional sequence at Surmont (see Section 5.2.4), where the sands and mudstones of the McMurray channel sediments are randomly and unpredictably distributed. The Board maintains that mudstones within channel sequences are not laterally extensive and, therefore, will act only as baffles to pressure transmission.

The Board also recognizes the presence of multiple fluid contacts within the McMurray A, B2, and C sand sequences. The Board agrees with AEC, BP Canada, CGP, Devon, Paramount, Rio Alto, and SSG that multiple fluid contacts within wellbores in the presence of regionally correlatable mudstones suggest vertical segregation. For example, as shown in Figure 11 (type well 00/12-16-80-9W4/0), stacked gas/bitumen, gas/bitumen, and water/bitumen contacts can be seen in the McMurray A, McMurray B2, and McMurray C sands respectively. If the McMurray A and McMurray B mudstones were not effective barriers, gas would have filled the pore space within the McMurray A sand, displacing the oil before it degraded to bitumen.

Nexen and PanCanadian argued that in areas of sparse drilling, the occurrence of multiple fluid contacts within the Wabiskaw-McMurray does not imply that the trap, or mudstone, extends for any significant distance. In particular, PanCanadian proposed that perched gas and top water pools could be trapped locally by small, impermeable mudstones within the channel sediments. The Board agrees that in the absence of regional mudstones, multiple fluid contacts within channel sequences do not necessarily imply segregation of gas from underlying bitumen zones. Similarly, data from segregated pressure tests would not be conclusive in this environment, as bitumen could act as a barrier to pressure transmission. The Board finds that in circumstances where more than one gas zone is encountered in a wellbore and a regional mudstone is not identified, the lower gas pool is often limited in size (i.e., is a single-well pool). As such, the upper gas pool has the potential to be in vertical communication with the underlying bitumen beyond the edges of the lower mudstone. An example of where the Board believes this occurs is the 00/4-1-76-6W4/0 well (Figure 12).

Within the Chard-Leismer area, the Board notes that there is very little pressure data from segregated gas zones. The Board believes that this is due to the limited availability of such pressure data in the Chard-Leismer area because of the amount of commingled gas production that is occurring. The majority of the pressure data from segregated gas zones that demonstrate zonal isolation are from wells located in areas where the Board interprets the McMurray A and/or B regional mudstones to have been preserved (i.e., no channelling). Therefore, although the Board found some of the segregated pressure data to be of questionable quality, it believes that the data generally support its geological interpretation.

BP Canada submitted segregated gas and bitumen zone pressure data for the 00/5-15-77-6W4/0 (5-15) well that was acquired using a Multi Sample Formation Test (MSFT) tool to support its contention that vertical pressure isolation can occur in the absence of a regionally correlatable mudstone. BP Canada contended that the MSFT tool data show strong evidence of a pressure seal and a separate gas over water over bitumen over gas relationship between the McMurray upper gas zone and underlying bitumen. The Board notes that the EUB had previously denied gas production from the 5-15 well and that the letter of disposition contained the following comments regarding the bitumen zone pressure data:

- The MSFT tool is believed to have serious limitations in providing valid pressures in high viscosity bitumen. This is due to the small sample size coupled with little or no mobile fluid within the bitumen zone.

- BP Canada's conclusion that a valid pressure in the bitumen zone can prove the presence of an effective shale barrier is questionable for high viscosity bitumen. Since the bitumen is unable to flow at reservoir conditions it is expected to act as a barrier to pressure communication, just as a sealing shale would.

The Board believes that the above comments regarding the bitumen zone pressure data are still applicable.

The Board notes that there was no evidence presented and very little discussion at the hearing relating to the thermal degradation of shales or mudstones. The Board is concerned that thin shales or mudstones exposed to thermal conditions from a SAGD steam chamber may not remain competent barriers. Core and log data indicate that both the McMurray A and B regional mudstones are typically about 1 m thick in the Chard-Leismer area. Although the Board believes that this could present a risk for future SAGD bitumen recovery, it is prepared to accept, in the absence of evidence to the contrary, that these mudstones would remain competent in a thermal environment. The Wabiskaw D shale, however, varies in thickness over the Chard-Leismer area, from being absent in the western portion of Leismer to about 2 m thick in the Chard area. As a result, and until further data become available, the Board has decided to assume that where the Wabiskaw D shale is greater than or equal to 0.5 m thick, it would remain competent in the presence of a SAGD steam chamber, and where it is less than 0.5 m thick, it would not remain competent.

On the basis of the above, the Board has concluded that throughout Chard-Leismer, there are circumstances where vertical pressure communication is not likely to occur and circumstances where it is made possible by the erosion of regional mudstones and shales. These circumstances are described as follows:

- Where the McMurray B regional mudstone is absent, potential for vertical communication through all sediments below the McMurray A regional mudstone is likely. Although the

McMurray B1 sand might be present, the Board does not recognize a regional mudstone associated with or underlying this sand. As such, if the McMurray B regional mudstone is absent, as shown in Figure 13 (type well 00/4-4-76-6W4/0), the McMurray B1 sand is potentially in vertical communication with underlying sediments.

- Where the McMurray A regional mudstone is absent but the McMurray B regional mudstone is present, the Board believes that the sand above the McMurray B regional mudstone remains vertically isolated from underlying sediments.

- Where both the McMurray A and B regional mudstones are absent, all sediments below the Wabiskaw D shale have the potential to be in vertical communication. The Board agrees with Nexen and Petro-Canada that there are numerous wells in the Chard-Leismer area where the entire McMurray sequence consists of sandy fluvial-estuarine sediments in vertical continuity. Many of these wells demonstrate direct association of gas with underlying bitumen, as shown in Figure 14 (type well 00/7-13-80-7W4/0).

- Where the Wabiskaw D shale is absent or less than 0.5 m thick, isolation of the overlying Wabiskaw C sand from underlying McMurray channel bitumen is dependent on the presence of either the McMurray A or B regional mudstones. If either regional mudstone is present, as shown in Figure 13 (type well 00/4-4-76-6W4/0), the Wabiskaw C sand is considered to be vertically isolated from bitumen underlying that mudstone. If both regional mudstones are absent, as shown in Figure 15 (type well 00/9-34-77-8W4/0), the Wabiskaw C sand has the potential to be in vertical communication with underlying bitumen.

- Where the Wabiskaw C channel has removed the regional Wabiskaw D shale and McMurray A and B mudstones (e.g., Twp 76-7W4), the Board continues to believe, as stated in *Decision 2001-64*, that there is potential for vertical communication between the Wabiskaw C channel gas and underlying McMurray channel bitumen.

5.3.2 Piezometer Data and Models

The Board notes that the issues surrounding the piezometer data at the hearing fell into two categories. The first concerned the nature of the instrumentation, the mode of installation of the piezometers, and the operation of the piezometers. The second category concerned the interpretation and meaning of pressure trends recorded by the piezometers over time. The main issues were the nature or type of the pressure changes observed, the source of the pressure changes, and the pathways that pressure transients may have taken from their source to a responding piezometer.

The reliability of the piezometer instrumentation was discussed at length at the hearing. The Board heard that the vibrating-wire technology employed in the actual piezometer device is calibrated at the factory, that piezometers have been installed by operators throughout the oil sands areas, and that they have an appreciable chance of surviving installation procedures. Moreover, the Board heard that if the piezometers were to fail gradually after installation, the resulting bias would be towards continually increasing pressures over time. Since nearly all of the piezometer data showed declining pressure trends over time, this suggests the functioning vibrating-wire piezometers are likely reading true; however, the Board cannot rule out the possibility the piezometers are experiencing drift of an unknown nature. Other evidence showed that the instruments are sensitive to input voltage changes at surface. In the future, the Board expects proper steps to be taken to avoid such disruptions by operators who choose to use this technology. Furthermore, the Board expects that operators will maintain careful documentation of their operating practices to aid in piezometer interpretation.

The Board notes that two types of pressure changes were identified by Petro-Canada and PanCanadian. The first type is represented by the overall degree of departure in the observed pressures from estimated virgin formation pressures. The second type is the ongoing pressure decline over time observed in many of the piezometers, as mentioned above. With respect to the degree of departure from estimated virgin pressures, the Board notes that all of the piezometers discussed at the hearing were installed subsequent to the commencement of overlying or close-offset gas production. Therefore, the Board is of the opinion that there is no conclusive way to establish baseline pressures at these piezometer locations. Given this situation, estimates of the baseline pressures were made by both bitumen and gas producers by extrapolating hydrostatic pressure-depth gradients downward from virgin gas pool pressures corrected to their gas-water interfaces. The Board notes that the regional hydraulic head maps discussed in *Decision 2000-22* indicate regional downward flow across the McMurray Formation. Consequently, the Board believes that a subhydrostatic pressure-depth gradient would have been more appropriate to use in this context. Had this been done, the estimated baseline pressures at piezometer depths would have been lower, as would the estimated departures from baseline. But even after allowing for the possibility of such an interpretive bias, the Board accepts that the piezometers in the upper part of the McMurray at the 02/9-24-80-7W4/0 and the 5-16 and 6C-16-76-6W4/0 wells are reading pressures that are less in magnitude than a reasonable estimate of virgin pressures.

The second type of pressure change evident in many of the piezometers is a generally continuous decline in pressure with time. The Board heard that there were exceptions to these trends in the submitted evidence (i.e., where pressures were observed to increase rather than decrease). Some of these reversals were relatively easy to explain, being clearly associated with change in operating procedure, as in the case of voltage changes affecting the 02/9-24-80-7W4/0 well piezometers, or the pressure changes associated with drilling of nearby horizontal wells, as was the case of the 5-16-76-6W4/0 and 6C-16-76-6W4/0 well piezometers. However, the Board finds the reversal of pressures in McMurray bottom water as detected at the AA/10-26-81-7W4/0 well piezometer difficult to explain. These data show an apparent rise in the bottom water pressure following shut-in of gas at Surmont. But unlike the other piezometer data entered as evidence, these pressure data were collected at discrete time intervals rather than continuously. Moreover, the pressure appears to begin to rise prior to the shut-in order. The lack of continuous data and the suggestion of pre-shut-in pressure rise makes it difficult to determine whether the pressure reversal was indeed linked to cessation of overlying gas production or was due to some other cause.

With regard to the nature of the declining pressure trends observed over time, the Board agrees with EnCana that in the absence of any other information, these changes in pressure over time are as likely to represent 1) instrument drift of an unknown origin, 2) the decaying remnant of drilling-induced pressure pulses around the borehole, or 3) the transmittal of pressure decline down the borehole, as they are to be due to the effects of overlying gas production being transmitted vertically through the formation away from the borehole. The Board also notes that evidence showing vertically separate piezometers in the same borehole tracking each other's pressure behaviour with little or no damping or time lag attests to the possibility of such borehole-associated pathways existing. In general, the Board recognizes that pressure-transmission via borehole pathways is impossible to distinguish from pressure-transmission vertically through the formation and across bedding. Because multiple interpretations of the piezometer data are possible, the Board finds it cannot use the submitted piezometer data to ascertain the degree of vertical penetration of pressure transients from top gas downwards into bitumen-bearing zones at Chard-Leismer.

The CGP used a hydrogeological model to explain the vertical hydraulic relationships between piezometer responses at the 00/10-30-80-6W4/0 and 02/9-24-80-7W4/0 wells. The CGP explained the pressure drop between the gas and the underlying bitumen column as being caused by flow across the low-permeability mudstone. The CGP then used a superhydrostatic pore-pressure gradient through three of the four piezometer data-points below the mudstone to argue that there is only a very low vertical pressure drop in the bitumen and that the bitumen column is isolated from overlying gas production. The Board notes that the superhydrostatic vertical pore-pressure gradient needed to join those three points would actually be indicative of upward flow, not undisturbed hydrostatic pressures. Therefore, the CGP argument becomes self-contradicting if such a gradient must be invoked to explain vertical pressure relationships in the bitumen column while simultaneously invoking downward flow to explain the pressure drop across the mudstone. The Board therefore rejects the CGP's model.

5.3.3 Vertical Permeability Measurements and Analogs

The Board notes the wide range of vertical permeability values referred to by the hearing participants:

- 2 to 12 Darcies (D) at Leismer and 3 to 7 D at Foster Creek in massive McMurray oil sands, confirmed by several gas producers according to Nexen;
- 2.81 to 427 millidarcies (mD) in IHS mudstones and 0.01 to 4.42 mD in mudstones in the Christina Lake area, according to PanCanadian;
- 0.000003 to 1.84 mD in mudstones in the Chard and Surmont areas, according to Petro-Canada.

While the Board agrees that the vertical permeability of mudstones can be very low, it also agrees with Petro-Canada, Nexen, and Newmont that the lateral extent of the mudstones must be considered in determining the effective vertical permeability. As stated in Section 5.2.3, the Board believes the lateral continuity of the mudstones is dependent upon their depositional setting.

With respect to the Prudhoe Bay analog submitted by the CGP, the Board notes that the analog used the Leopold and Wolman correlation of stream channel height and width. The Board questions the applicability of this to the areal extent of mudstones within the channels in the geologically complex McMurray. Regarding the CGP's claim that the analog yields a model of vertical permeability in heterolithic strata that can be used with other data to match Petro-Canada's piezometer data, as stated in Section 6.2, the Board does not believe the history match of the piezometer data was able to determine the vertical permeability within any useful bounds.

5.4 Lateral Continuity

Lateral communication in this section refers to the potential for lateral communication of gas pools and top water zones in regional sands with gas pools and top water zones in channel sands as a result of sand on sand contact between the two facies.

5.4.1 Regions of Influence

Similar to the situation at Surmont, the Board believes that it is not possible to definitively establish the actual size and shape of the regions of influence at Chard-Leismer with the available data and knowledge about the geometry, heterogeneity, and properties of the Wabiskaw-McMurray gas pools and top water zones and without clear scenarios for gas production. Petro-Canada proposed some changes to the Board's concept of a region of influence by using ROHC. However, as stated in Section 5.1.1, the Board does not accept that Petro-Canada's potentiometric maps can be used to identify minimum regions of influence in the manner proposed. As such, the Board continues to believe that the minimum size of a region of influence is the extent of a gas pool directly overlying bitumen or the combined extent of the gas pool and top water zone in the case of gas overlying water overlying bitumen, as defined in *ID 99-1*.

5.4.2 Geological and Pressure Data

The Board notes Nexen's argument that the available pressure data are not of sufficient quality to make definitive interpretations as to the size of the regions of influence at Nexen's Leismer oil sands leases. The Board agrees with Nexen and further recognizes that there are limited pressure data of questionable quality for many of the wells in the Chard-Leismer area due to infrequent pressure testing, the amount of commingled gas production in the area, and the practice of measuring pressure at the surface. Additional pressure data through time (i.e., time series) for individual zones would be required to refine pool and region of influence delineations. As a result, the Board relied more on geological correlation and common gas/water, gas/bitumen, and water/bitumen contacts to estimate the extent of the regions of influence in the Chard-Leismer area.

The Board agrees with Nexen that late changes in structure due to the influence of salt collapse caused vertical displacement of the stratigraphic section, resulting in varying water/bitumen contacts within the same pools. Nexen stated that it is not necessary for top water to have the same structural elevation to be continuous. Notwithstanding, the Board applied a ±2 m tolerance to the water/bitumen contact to determine what it believes to be a reasonable estimate of the extent of top water zones.

The Board agrees with AEC, CGP, Devon, and Rio Alto that the gas pools at Chard-Leismer are generally small in size, with the exception of the regional Wabiskaw C gas pools. However, as discussed in Section 5.2.2, the regional Wabiskaw C sand overlies the McMurray sediments in a higher stratigraphic position and is not in lateral communication with bitumen-filled McMurray channels.

Wabiskaw C channel gas pools were identified only in Twps 75-7W4 and 76-7W4 (i.e., in the area of Newmont's oil sands leases). In this area, the complex stratigraphy created by a late channel event and the limited pressure data available make it difficult to determine if lateral communication with offsetting regional Wabiskaw C sand is occurring.

Wabiskaw D valley-fill gas pools were prominent in two areas of Chard-Leismer: Twp 76-6W4 and Twps 79-9W4 and 79-10W4. These pools, based on fluid contacts, are relatively small, ranging in size from 1 to 5 sections. Associated top water is locally present, but not extensive, appearing to be confined to the extent of the gas pool. The Wabiskaw D gas does not appear to be in lateral communication with offsetting channels. However, there is the potential for vertical communication due to the absence of any regionally correlatable mudstones or shales in spite of the presence of multiple gas/bitumen contacts.

The Board finds the gas pools within the McMurray A regional sand to be relatively small, most commonly 2 to 3 sections in size. However, these pools are generally associated with much larger top water zones, ranging from 8 sections to 2 townships in size. Each of these top water zones was associated with two or more gas pools. Considering the lateral extent of the top water, the Board believes that gas production from any of these pools could have a broad influence. The Board does not interpret the McMurray A regional sand gas pools to be connected with gas within laterally offsetting channel sediments, nor the McMurray A regional top water zones to be connected with top water within laterally offsetting channel sediments. However, Petro-Canada described several situations where it interpreted vertical and lateral pressure communication to exist between uppermost bayfill top gas and uppermost channel top gas, top water, and bitumen. The Board's detailed assessment of these situations is discussed below:

- Petro-Canada interpreted lateral communication of McMurray A gas at the 00/10-11-80-7W4/0 (10-11) and 00/7-14-80-7W4/0 (7-14) wells with McMurray channel gas at the 00/7-13-80-7W4/0 (7-13) well.[3] The Board agrees with Petro-Canada that the McMurray A gas at the 10-11 and 7-14 wells fits structurally with the gas in the McMurray channel at the 7-13 well. Both the 10-11 and 7-14 wells experienced pressure decline before production. The Board believes this decline to be caused by McMurray A gas production at the 00/10-23-80-7W4/0 well, which it has pooled with the 10-11 and 7-14 wells. This pool recorded a pressure of 250 kilopascals absolute (kPaa) in 2001. However, at the same time, a pressure of 1084 kPaa was reported for the 7-13 well. Based on the significant pressure difference, the Board does not agree with Petro-Canada's contention that lateral communication is occurring between McMurray A gas at the 10-11 and 7-14 wells and McMurray channel gas at the 7-13 well. This is consistent with the general finding of the Board that McMurray A gas pools are isolated from McMurray channel gas pools and top water zones.

- Petro-Canada interpreted lateral communication of McMurray A gas at the 00/6-17-81-7W4/0 (6-17) well with McMurray channel gas at the 00/10-16-81-7W4/0 (10-16) well.[4] Gas production from McMurray A and McMurray channel at the 6-17 well is commingled. Both gas zones at the 6-17 well fit structurally with McMurray channel gas at the 10-16 well. The 6-17 well experienced a pressure decline prior to production, but its commingled pressure

[3] Exhibit No. 1309, Section II.5, Figures II.5.4-b and II.5.4-c.
[4] Exhibit No. 1309, Section II.5, Figure II.5.4-d.

does not fit the pressure trend of the McMurray channel gas pool at the 10-16 well. This suggests that only one of the gas zones at the 6-17 well is in lateral communication with channel gas at the 10-16 well. Although it is possible that McMurray A gas at the 6-17 well is in lateral communication with channel gas at the 10-16 well, based on its review of the Chard-Leismer area, the Board believes that it is more likely that only the McMurray channel gas at the 6-17 well is in lateral communication with channel gas at the 10-16 well.

- Petro-Canada interpreted lateral communication of McMurray channel gas at the 00/6-20-80-6W4/0 (6-20) well with McMurray A gas at the 00/6-22-80-6W4/0 (6-22) well.[5] McMurray channel gas at the 6-20 well had a depleted initial pressure of 1085 kPaa in 1996. The 6-22 well had three pressure measurements that showed the well had depleted below 1085 kPaa before 1996: 1000 kPaa in 1993, 850 kPaa in 1994, and 770 kPaa in 1995. Based on the pressure data, the Board concludes that McMurray channel gas at the 6-20 well is not in lateral communication with McMurray A gas at the 6-22 well.

- Petro-Canada interpreted lateral communication of McMurray A gas at the 00/8-7-81-7W4/0 (8-7) well with McMurray channel gas at the 00/10-16-81-7W4/0 (10-16) well.[6] The gas/bitumen interface in the McMurray A sand at the 8-7 well is at +273.5 m sea level, while the gas/bitumen interface in the McMurray channel at the 10-16 well is at +259.4 m sea level (i.e., 14.1 m lower). Given the significant difference in elevation of the gas/bitumen interfaces, the Board does not agree with Petro-Canada that lateral communication exists between McMurray A gas at the 8-17 well and McMurray channel gas at the 10-16 well.

The Board found that although in most circumstances gas within the McMurray B1 regional sand is not connected with gas within laterally offsetting McMurray channel sand, there are situations where this is not the case. For instance, Petro-Canada interpreted lateral communication of McMurray B1 gas at the 00/12-35-79-7W4/0 (12-35) and 00/12-36-79-7W4/0 (12-26) wells with McMurray channel gas at the 00/12-31-79-6W4/0 (12-31) well.[7] A depleted pressure was measured from the McMurray channel gas zone at the 12-31 well without any production being taken from the well. The depletion is most reasonably attributed to production from McMurray B1 gas at the 12-35 and 12-36 wells, which fit structurally with McMurray channel gas at the 12-31 well. However, due to the lack of recent pressure data from the 12-35 well and the commingled pressure data from the 12-36 well, it is not possible to confirm lateral communication from pressure data. The Board is prepared to accept Petro-Canada's argument that there is lateral communication between McMurray B1 gas and McMurray channel gas in this instance.

The McMurray B2 sand is not a major gas reservoir in the Chard-Leismer area because of its poor preservation due to channelling and its lower stratigraphic position within the Wabiskaw-McMurray interval (i.e., below the gas-bearing sands). The McMurray B2 gas pools range in size from one to three sections and rarely have associated top water. Gas in this sand is not interpreted to be connected laterally with offsetting McMurray channel gas.

Based on its review of the gas and top water zones, the Board disagrees with Nexen, Newmont,

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[5] Exhibit No. 1309, Section II.5, Figure II.5.4-e.
[6] Exhibit No. 1309, Section II.5, Figure II.5.5-a.
[7] Exhibit No. 1309, Section II.5, Figure II.5.5-d.

and Petro-Canada that lateral communication pathways commonly exist between regional Wabiskaw C, McMurray A, and McMurray B2 sands and McMurray channel sands. With respect to the potential for lateral communication between McMurray B1 sand and McMurray channel sand, the Board found only three such instances.

The Board finds the gas pools within the McMurray channel sand to be relatively small, most commonly one to four sections in size. However, the Board agrees with Nexen and Petro-Canada that these gas pools are generally associated with much larger top water zones. The Board further concurs with both Nexen and Petro-Canada that the water zones range from two sections to a township in size and that they are typically associated with more than one gas pool.

As stated in Section 5.2.4, the McMurray channel sand was deposited in a fluvial-estuarine channel setting, resulting in heterogeneous sediment distribution, and is similar to the Wabiskaw-McMurray sand at Surmont. Similarly, although direct association of gas and bitumen or indirect association through top water may not be apparent in any particular well, it is possible for gas production from that well to affect nearby bitumen as a result of lateral continuity. Considering the potential lateral extent of the top water in the McMurray channel sand, gas production from any of the McMurray channel gas pools could have a broad influence. Therefore, the Board concludes that all McMurray channel gas in the Chard-Leismer area is or has the potential to be associated with underlying bitumen, either through direct vertical continuity or indirectly through lateral continuity of the gas and water zones.

In summary, the Board concludes that

- lateral communication pathways do not commonly exist between regional Wabiskaw C, McMurray A, McMurray B2, and Wabiskaw D valley-fill gas pools and/or top water zones and McMurray channel gas pools and/or top water zones;

- the potential for lateral communication between McMurray B1 gas pools and McMurray channel gas pools is limited; and

- the potential exists for McMurray channel gas pools to be associated with underlying channel bitumen.

6 EFFECT OF ASSOCIATED GAS PRODUCTION ON SAGD BITUMEN RECOVERY

The evidence submitted to the Chard-Leismer hearing regarding the effect of associated gas production on SAGD bitumen recovery consisted of field experience and model studies, as was the case in the Surmont hearing. Although much of the field experience submitted to the Chard-Leismer hearing was related to the same schemes that were discussed at the Surmont hearing, there were significantly more model studies submitted to the subject proceeding. At the Chard-Leismer hearing, three parties opposed to and five parties (which includes the separate studies submitted by Northstar and Anderson) in favour of gas production submitted model studies, while at the Surmont hearing, two parties opposed to and one party in favour of gas production submitted model studies.

6.1 Field Experience

Regarding the Kearl Lake pilot, the Board previously agreed in *Decision 2000-22* that the pilot provided a field example of the negative effect that a low-pressure thief zone can have on a gravity-dominated steam injection process. However, since a SAGD operation at Surmont would not be totally analogous to the operations conducted at the Kearl Lake pilot, the Board stated that it believed the results from Kearl Lake could not be applied directly to Surmont. The Board believes this statement also applies to Chard-Leismer.

Regarding the Dover pilot, the Board previously concluded in *Decision 2000-22* that the geology at Dover is not an appropriate analog for the Surmont area and, therefore, the extent of steam rise observed at the Dover pilot could not be relied on to determine the extent of steam rise at Surmont. No direct comparison was made between the geology at Dover and that at Chard-Leismer. Also, in Section 5.2.4 the Board concluded that, similar to Surmont, the occurrence of thick, sand-filled channels is extensive and randomly distributed in the channel environments at Chard-Leismer. The Board therefore believes that at this time it is not appropriate to apply any conclusions regarding the rate of steam rise at the Dover pilot to the Chard-Leismer area.

Two pieces of evidence presented at the Chard-Leismer hearing regarding the Dover pilot were not presented at the Surmont hearing: the Ito paper[8] and EnCana's statement that Dover was operated down to a pressure of 800 kPaa. With respect to the Ito paper, the Board notes that there was no argument among the hearing participants with the conclusion that bitumen has been recovered from the IHS zone, but there was disagreement about the extent of steam penetration into this zone. Regarding EnCana's statement that Dover was operated down to 800 kPaa, the Board's understanding of the evidence is that only the B1 well pair was operated at progressively decreasing pressures of 1800 to 800 kPaa for the first five months of operation. The Board does not consider this to be very significant because of the short duration and the limitation to one well pair.

With regard to the Conoco Surmont pilot, the Board agrees with Conoco that it is not appropriate to make conclusions about the pilot performance without knowing the operational history, the objectives of the pilot, and the nature of the experiments that have been conducted. The Board does not believe that the evidence about California and Saskatchewan low-pressure thermal projects presented by EnCana is directly analogous to Chard-Leismer for the reasons provided by Newmont: they are steamfloods rather than SAGD schemes, they had primary oil production, and they do not involve the presence of top gas and top water thief zones. Nexen's reference to the issue of bottom water/transition zone water at EnCana's Foster Creek and Christina Lake SAGD schemes is addressed in Section 6.2.

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8 Exhibit No. 314, Ito, Y., Hirata, T., and Ichikawa, M., "The Growth of the Steam Chamber During the Early Period of the UTF Phase B and Hangingstone Phase I Projects," *Journal of Canadian Petroleum Technology*, Sept. 2001.

The Board concludes that the current situation with respect to field experience is not much different than the situation at the time of the Surmont hearing: there is very limited applicable field experience regarding the effect of associated gas production on SAGD bitumen recovery.

6.2 Studies

A major factor involved in modelling the effect of gas production on SAGD bitumen recovery is the geological description used in the model. Considering the complex nature of the Wabiskaw-McMurray, developing an appropriate geological description is a challenging task. In general, the hearing participants used two different approaches to develop geological descriptions:

- generic models that were more conceptual in nature but arguably were based on some field geological, petrophysical, and/or core data; and
- well-specific models based on one or more wells.

The Board views the models submitted by Petro-Canada (excluding the Syncrude Mineface model), Nexen, and EnCana to be generic models and the models submitted by CGP, Devon, BP Canada, and Newmont to be well-specific models.

Considering the complex nature of the Wabiskaw-McMurray, the Board believes there are limitations with both approaches, and the Board certainly heard considerable debate about the geological descriptions used in the model studies. The Board acknowledges that the generic models have much more homogeneity than is observed in specific wells. On the other hand, the Board is not convinced that in a channel environment it is appropriate to extend heterogeneities observed at one or more specific wells across the entire area of the modelled region. In particular, the Board agrees with Petro-Canada and the SSG's criticism about the long correlation lengths used in the CGP's August 2001 model. In addition, it questions the applicability of the Leopold and Wolman correlation of stream channel height and width and the application of this to the areal extent of mudstones within the channels in the geologically complex McMurray Formation.

Another aspect of the geological description is how the thief zones were modelled, which varied from unconfined, to confined, to no thief zone at all. The Board recognizes that modelling thief zones as unconfined with constant pressure wells is one extreme. However, confining the thief zone to the extent of the gas zone compared to the possible developable bitumen area may not be appropriate. As acknowledged by the CGP, use of a gas zone to bitumen zone ratio based on full SAGD development in the symmetry element used in the modelling assumes that the steam chamber for all well pairs would break through at the same time, which is probably not realistic. Also, only a portion of the bitumen area may be developed initially, in which case using the full SAGD development area would result in too small a gas zone to bitumen zone ratio. In addition, the extent of top water zones needs to be considered and, as discussed in Section 5.4, the Board believes that the gas pools within the McMurray channel sands are generally associated with larger top water zones. The Board does not accept EnCana's argument that the results of its modelling, which did not include a thief zone, are in some ways more reliable, because reservoir heterogeneities such as water sands, permeability variations, and barriers can lead to results that are site specific and unusually sensitive to the operating details. While the inclusion of reservoir heterogeneities such as thief zones adds complications, the Board believes that where they occur, their effects should be considered. With respect to the CGP's argument that much of what Petro-

Canada calls top water is low-resistivity muddy strata (i.e., nonreservoir material), the Board interprets the zone to be top water. In the Board's view, the logs and core indicate this interval contains porous water-saturated sands interspersed with muddy strata.

With respect to Petro-Canada and Nexen including a breakthrough column as part of their models, the Board agrees with the concept and purpose of the breakthrough column: to capture the impact of the uneven rise of the steam chamber along a horizontal well. However, the Board recognizes that determining the properties of the breakthrough column is subject to interpretation, and this adds further uncertainty to the model results.

Regarding the attempt to determine the vertical permeability by history matching the two Petro-Canada piezometers in the Chard area, the Board is inclined to agree with EnCana's view that there is probably as much uncertainty in the relative permeability to water as there is to the absolute vertical permeability. As a result, history matching the piezometer data can only be used to determine the product of the absolute vertical permeability multiplied by the water relative permeability, and not the individual values. Consequently, the Board believes the history matching does not establish the value of the vertical permeability within any useful bounds.

Although Petro-Canada included a detailed geological description in its Syncrude Mineface model, the Board has not given any weight to that study. The Board believes the model could not be properly tested since it included the use of a proprietary outcrop study that, although requested by the CGP, was not provided by Petro-Canada.

Another important factor involved in the modelling is the operating strategy used. The Board agrees with EnCana's criticism of Petro-Canada operating its models in such a way as to try to keep the instantaneous steam-oil ratio approximately constant at different pressures. This is not consistent with the expectation that the cumulative steam-oil ratio would be lower at lower pressures. The Board also agrees with Nexen's criticism of BP Canada's use of constant steam injection rates in its models, which resulted (at least in some of the runs) in approximately one-half the injected steam being produced. However, the Board does take note of BP Canada's response that in its view, although steam trap control can be easily implemented in a model, it is very difficult, if not impossible, to implement in the field. This indicates to the Board that operating strategies used in models may not always be possible to implement in the field, and this needs to be factored in when considering the results of model studies.

With respect to the potential geomechanical effects included by Newmont in its models, the Board agrees with Devon that geomechanical effects are not likely to have much relevance to the gas/bitumen issue at Newmont's oil sands leases. Newmont acknowledged that it could only operate at pressures sufficient to reduce the confining stress to zero during the period prior to the breakthrough of steam into the thief zone, and this period was expected to be only six months to one year. After that the SAGD operating pressure would have to be optimized to ensure that the steam zone pressure matched that of the thief zone. Since the initial pressures of the gas zones in the vicinity of Newmont's oil sand leases are approximately 2000 kPaa, whether or not the gas is produced, the gas zone pressure would be below the level at which significant geomechanical effects are likely to occur. Geomechanical effects are further discussed in Section 7.

The Board agrees with EnCana that bitumen recoveries should be compared on a net energy basis to account for the fuel requirements for SAGD schemes. This would improve the bitumen recovery at low pressure compared to that at high pressure based on the expectation that the cumulative steam-oil ratio would be lower at lower pressure. The extent of the improvement would depend on how much the cumulative steam-oil ratio would be reduced at the lower pressure. On the other hand, as pointed out by Petro-Canada, Nexen, and Newmont, there are several risk factors related to low-pressure operation that were not taken into account in most of the model studies, such as the increase in residual oil saturation with reduced pressure, water influx from the top water zone, solution gas effects, and the feasibility of low-pressure artificial lift (which is further discussed in Section 9). Although there was extensive debate about the significance of these factors in the modelling, the Board still views them as risk factors that need to be considered. In addition to these factors, the Board views bottom water as an additional risk factor associated with lower pressure. Although EnCana argued in favour of low-pressure SAGD, it stated that it was necessary for it to operate its SAGD schemes at Foster Creek and Christina Lake at or near the initial reservoir pressure because of the concern about producing bottom water/transition zone water. Evidence on the extent of bottom water throughout the Chard-Leismer area was not provided at the hearing. However, Petro-Canada provided evidence regarding the presence of bottom water in part of the Chard area and EnCana indicated the presence of bottom water in the Christina Lake area. The Board also notes that EnCana conceded the criticism of its assumption of a 10 per cent wind-down recovery for all the cases included in its model study, as well as that based on Nexen's model results. EnCana estimated that the wind-down recovery could decrease from about 7 per cent at 1900 kPaa to about 2 per cent at 200 kPaa.

As pointed out in Section 6.1, there is still very limited applicable field experience regarding the effect of associated gas production on SAGD bitumen recovery. Hence, the Board must continue to rely on reservoir modelling to evaluate the issue. Based on its assessment of the model studies submitted and subject to its views on artificial repressuring discussed in Section 8, the Board concludes that producing gas that is associated with bitumen, such as at the high-risk wells identified in Section 11, presents an unacceptable risk to SAGD bitumen recovery.

7 GEOMECHANICAL EFFECTS

Newmont submitted that with an optimum SAGD injection pressure of 5500 kPaa at its Leismer oil sands leases during the first six months to one year of operation, some degree of dilation, shearing, and associated permeability improvement would occur around each injection well. After this period, steam breakthrough would be expected to occur into the much lower pressured gas zone immediately above and continuous with the bitumen zone. To prevent steam loss into the gas zone, the injection pressure would have to be reduced to match the gas zone pressure. The Board notes that virgin gas zone pressures in the Leismer area are approximately 2000 kPaa. Therefore, even if the gas zone overlying Newmont's leases was still at virgin pressure, only a limited amount of geomechanical effects would be induced prior to steam breakthrough at a SAGD injection pressure of 5500 kPaa. While thermal stresses may develop around the injection wells, the Board believes that there would be no subsequent geomechanical effects at or below injection pressures of 2000 kPaa.

Newmont submitted that geotechnical field instrumentation monitoring data from the Dover

SAGD pilot showed apparent horizontal and vertical movements, together with shearing and/or expansion, occurring within and immediately adjacent to the SAGD steam chamber. The SAGD injection pressure at Dover was about 2600 kPaa, and there is no gas zone in communication with the Dover SAGD operation. Furthermore, the average bitumen depth at Dover is about 150 m, while the average bitumen depth at Newmont's leases is about 375 m. Therefore, the Board believes that the complexity of geomechanical stresses at Newmont's leases would be significantly greater and different from those that exist at Dover. On the basis of the above, the Board concludes that geomechanical effects at the Dover SAGD pilot cannot be directly extrapolated to predict geomechanical effects or any associated improvements in performance for a potential SAGD project at Newmont's Leismer leases.

8 FEASIBILITY OF ARTIFICIAL REPRESSURING

The Board acknowledges that repressuring has been demonstrated to be viable in the context of gas storage schemes throughout North America, but notes that repressuring of a depleted gas zone has not yet been proven feasible and practical in the Wabiskaw-McMurray. In this respect, although the Board accepts that Devon has conducted equipment trials of its exhaust gas compression system at its Dover SAGD project, the Board agrees with Newmont that the injection of exhaust gas into a steam chamber at Dover is not analogous to repressuring a depleted gas zone. The Board encourages repressuring projects, such as that jointly proposed by EnCana and Devon to repressure a depleted gas zone at Christina Lake. However, even if some repressuring projects were ultimately successful, the Board shares Petro-Canada's and Newmont's view that the viability and practicality of such projects would need to be assessed to determine whether the results are applicable to other areas and geological conditions. For example, the Board interprets that a top water zone is not present in the area of the proposed Christina Lake repressuring project, whereas, as discussed in Section 5.4, the Board interprets top water zones to be present and potentially laterally extensive in some portions of the Chard-Leismer area. Therefore, the Board believes that in some portions of Chard-Leismer, the potential exists for leak-off of pressure to low-pressure areas. Furthermore, the Board agrees with Petro-Canada and Nexen that if gas zone depressuring results in water influx and/or solution gas evolution, there is uncertainty as to whether repressuring would be able to reverse these processes. Although the Board acknowledges that in some situations repressuring of a depleted Wabiskaw-McMurray gas zone may be shown to be a viable option in the future, it continues to believe that repressuring should not be relied on until it has been proven to be feasible and practical on the basis of field tests.

9 FEASIBILITY OF ARTIFICIAL LIFT

In *Decision 2000-22*, the Board concluded that the minimum steam chamber pressure required for artificial lift to be technically feasible would be in the range of 400 to 600 kPaa. This conclusion was based on the general consensus of the Surmont hearing participants that the theoretical minimum steam chamber pressure would be in this range. In contrast, at the subject hearing, there was a considerable divergence of positions among the hearing participants regarding the limitations of artificial lift. For example, while several parties focused on the currently proven minimum pressure limit for artificial lift, which is significantly higher than the gas abandonment pressure, EnCana submitted that artificial lift is feasible at a minimum steam chamber pressure of 300 kPaa based on currently available technology, although it has not yet been tested in the field.

The Board notes that all parties that submitted evidence regarding artificial lift were in general agreement that gas lift is the only artificial lift technology that has been proven for use in commercial SAGD operations and that it is no longer an option in the hearing area at steam chamber pressures below 1650 to 2000 kPaa, depending on the reservoir depth. Therefore, since the current gas pool pressures in some portions of the hearing area are already below this pressure range, the Board agrees with BP Canada that if gas is associated with bitumen, artificial lift technology other than gas lift would have to be relied on for SAGD bitumen production in these areas.

The Board notes that the majority of the parties that submitted evidence regarding artificial lift were of the view that where gas lift is no longer an option, electric submersible pumps (ESPs) offer the greatest potential to be a workable option for SAGD bitumen production. The Board agrees with Devon that given the initiatives currently under way, it is reasonable to expect the practical application of ESPs for SAGD bitumen production in the foreseeable future. However, the Board believes that field testing is needed to definitively establish the operational limitations of ESPs (i.e., pressure, temperature, configuration). In this respect, the Board notes that EnCana installed and commenced operation of an ESP in the near horizontal portion of a SAGD well at its Foster Creek project in April 2002, but that very little information was submitted at the hearing regarding its operation. As a result, although the Board encourages these kinds of demonstrations, no conclusions can be made regarding the workability and long-term reliability of this type of ESP configuration and the associated operating parameters.

On the basis of the above, the Board concludes that the risks associated with SAGD bitumen production increase at lower operating pressures. As a result, the Board continues to believe that where gas is associated with bitumen, gas zone depressuring should be kept to a minimum to better ensure successful SAGD operations in terms of resource recovery and minimizing the technical difficulty of lifting SAGD fluids. Furthermore, in the absence of field data, the Board believes that its previous conclusion in *Decision 2000-22* that the minimum steam chamber pressure required for artificial lift to be technically feasible would be in the range of 400 to 600 kPaa is still a reasonable estimate.

10 ECONOMICS

The Board finds itself in approximately the same position it was in at the conclusion of the gas/bitumen inquiry in June 1997 with respect to assessing the commercial attractiveness of SAGD as a bitumen recovery process. Although the Board is encouraged that a number of experimental and commercial projects have been initiated since that time, the data required for such an assessment are either too limited to be of value or are considered proprietary. Nonetheless, bitumen leaseholders continue to express the view that SAGD will be a profitable process that will yield significant taxes and royalties. Gas producers argued that the bitumen leaseholders' economic analyses of prospective SAGD projects are likely exaggerated, as they are the product of theoretical models utilizing optimistic assumptions.

Although EnCana expressed confidence in its ability to repressure gas reservoirs at Christina Lake, the remaining participants appeared to be just as entrenched in their positions as during the inquiry and Surmont hearing vis-à-vis the potential value of longer-term bitumen production versus the short-term cost to gas producers and society of shutting in current gas production. The argument advanced by most of the bitumen leaseholders was that the dollar value to society of the bitumen resources amenable to SAGD compared to the value of the gas reserves requested to be shut in is essentially a comparison of billions to millions.

While the Board agrees that recoverable bitumen reserves ought to be defined as those that meet reasonably acceptable commercial criteria, the Board is not convinced that there is sufficient understanding of SAGD's capabilities and limitations to formulate the lower limits of those criteria. To underscore the uncertainty surrounding SAGD, the Board notes that there was expert, but variant, testimony presented on behalf of both sides of the issues on such fundamental engineering parameters as required pay thickness, optimal operating pressure, the presence or absence of barriers to pressure transference, steam-oil ratios, and the like. The disagreement over commercial factors (e.g., price forecasts, markets) seems almost trivial in comparison to the dispute over engineering and geologic factors. Hence, the identification of bitumen resources that might conform to reasonably acceptable commercial criteria remains, for the Board's purposes, largely an arbitrary exercise. However, in this context and having regard purely for effective resource conservation, that is, long-run economic efficiency, the Board believes that with SAGD technology still in its infancy, it has a responsibility to ensure that long-term bitumen recovery is not jeopardized by the production of gas that is in pressure communication with significant bitumen resources.

While the Board is hopeful that the technical and economic potential of SAGD will be clearly revealed before long, there remains the issue that decisions taken in the interim could have a significant impact on the welfare of future Albertans. If the interests of future generations of Albertans were not deemed worthy of consideration today, the Board could seriously consider the argument that there are ample bitumen resources in Alberta for our immediate requirements and that any resources rendered unrecoverable as a result of continued gas production are not of immediate concern. However, in addition to society's immediate needs, the Board believes that it should consider the longer-term aspects of resource development and the longer-term interests of future Albertans. Therefore, given the number of unknowns about the technical and economic parameters surrounding bitumen recovery (whether via SAGD or some other process), it would seem premature to abandon the issue in these early stages.

11 INDIVIDUAL APPLICATIONS

On the basis of its findings in the preceding sections, the Board concludes that Wabiskaw-McMurray gas production associated with channel bitumen (either through direct vertical continuity or indirectly through lateral continuity) in the Chard-Leismer area presents a significant risk to future bitumen recovery. Accordingly, the Board has assessed the Wabiskaw-McMurray gas zones in the wells included in the applications considered at the hearing with respect to whether or not these gas zones have a high or low potential to be in pressure communication with underlying channel bitumen. This assessment is based on the Board's conclusions regarding the Wabiskaw-McMurray stratigraphy and the potential for vertical and/or lateral communication (see Section 5). The results of this assessment are shown in Appendix 4 (Petro-Canada Chard area application wells) and Appendix 5 (Leismer Field Application wells). The Board has also assigned each gas zone with a category that explains why it has a high or low risk of being in pressure communication with underlying channel bitumen. These categories are described in Appendix 13. The Board has similarly assessed the wells that were included in the PanCanadian application to shut in gas production in the Christina Lake area. The results of this assessment are shown in Appendix 6. Although this application was withdrawn prior to the conclusion of the hearing, the Board has the authority to take action on its own initiative to meet its legislative duties.

The Board acknowledges that some of the gas zones identified as high risk in Appendices 4, 5, and 6 are at reservoir pressures below the Board's estimate of the minimum steam chamber pressure required for artificial lift to be technically feasible (see Section 9). However, because the potential exists for leak-off of pressure to low-pressure areas (see Section 8), the Board believes that gas production from these zones still represents a high risk to future bitumen recovery.

12 REGULATORY PROCESS

12.1 Alternatives to Current Criteria and Process for Approval to Produce Gas

Among the hearing participants there were sharply polarized views on the applicability and fairness of the current application and approval process for gas production in the oil sands areas. Petro-Canada asked the Board to reduce the risk to bitumen to zero or near zero by blanket prohibition of new and existing gas production, while a number of parties submitted that the current application process is unnecessary, since most applications are approved for production. It was argued that the time required to ensure adequate review of the relatively few cases where such review is necessary is not justified.

The Board believes that every effort must be made to ensure the efficiency of the process contemplated by *ID 99-1*. However, the Board notes the complex nature of the evidence forming the basis of the decisions being made and the need to ensure fairness. Accordingly, the Board would be prepared to review *ID 99-1* if sufficient evidence were submitted pointing to a problem with the current process. The Board does not find the evidence submitted to this proceeding to be sufficiently complete and conclusive to indicate what, if any, changes to *ID 99-1* are warranted. Therefore, the Board continues to believe that the current application process is appropriate to ensure that potentially at risk bitumen is not jeopardized.

12.2 Criteria/Process for Dealing with Grandfathered Gas Wells

With respect to Wabiskaw-McMurray grandfathered gas production in the Chard-Leismer area from wells not specifically considered at the subject hearing, the Board believes that some of the gas being produced by these 117 wells, shown in Appendix 3, could present a significant risk to future bitumen recovery. The Board also believes that some grandfathered gas production in other areas of the Athabasca Wabiskaw-McMurray deposit with a depositional environment similar to that at Chard-Leismer (i.e., fluvial-estuarine) could present a significant risk to future bitumen recovery. Therefore, the Board believes that there is a need to develop and implement a process to address grandfathered gas production in the Athabasca Wabiskaw-McMurray deposit (including Chard-Leismer), and it intends to pursue this matter.

The Board further notes that in the Chard-Leismer area there are 22 wells, shown in Appendix 3, that were previously granted approval to produce Wabiskaw-McMurray gas. On the basis of its findings in this proceeding, the Board believes that some of the gas being produced by these wells could also present a significant risk to future bitumen recovery. Therefore, the Board believes that these wells also need to be addressed in any process developed to deal with grandfathered production.

12.3 Data Collection/Submission Requirements

The Board received submissions on several aspects of data collection, including the need for increased pressure monitoring, the need for additional core within the Wabiskaw-McMurray, the use of seismic to identify the extent of bitumen resources, and the need for increased drilling density within areas of fluvial-estuarine environments.

12.3.1 Pressure Data

The Board notes that the hearing participants were in general agreement that pressure monitoring would assist in determining the presence or absence of pressure communication in the Wabiskaw-McMurray from both a lateral and vertical perspective. However, there was a significant departure in positions regarding whether or not the Board should mandate the implementation of a pressure-monitoring program. In particular, Petro-Canada requested that the Board require the implementation of a pressure-monitoring program in its Group 1 and 2 application wells (see Section 2.1), whereas the CGP argued that in the case of a gas shut-in order, pressure data collection requirements should be agreed to by the appropriate leaseholders on a site-specific basis.

In determining whether or not to direct the implementation of a pressure-monitoring program such as that proposed by Petro-Canada, the Board believes that the overall cost/benefit of such a program needs to be considered. Although the Board acknowledges that pressure monitoring would assist in validating its geological interpretation, the Board believes that the development and implementation of a properly designed program would be quite difficult, given such factors as the highly interpretive nature of pressure data from the Wabiskaw-McMurray and the amount of time needed to collect it. As a result, the Board is not convinced that the overall cost/benefit of such a program warrants the Board directing that one be implemented. Rather, the Board encourages gas and bitumen owners to cooperatively develop and implement a pressure-monitoring program acceptable to all parties. Also, if requested, the Board would be prepared to work with interested parties in this regard.

12.3.2 Core Data

The Board strongly believes that core data are essential to the identification and mapping of depositional environments, as discussed in Section 5.2. This is particularly true in identifying the nature and continuity of mudstones associated with gas and top water zones. *ID 99-1* requires that applicants obtain geophysical well log information to determine the nature and quality of potentially associated bitumen. Given that the nature of the separation between bitumen and gas zones is a critical factor in determining whether gas production should be allowed, the Board believes that core data substantially improve the ability to identify and correlate sands and mudstones. However, given the unconsolidated nature of the gas and water-bearing zones, the Board recognizes that there may be technical reasons why such coring may not be practical. As such, the Board encourages gas and bitumen producers to obtain, where practical, additional core data from the upper part of the Wabiskaw-McMurray, but will not make this a requirement.

12.3.3 Seismic Data

The Board heard evidence that seismic data can be useful in identifying areas of structural relief and thick sediments within the Wabiskaw-McMurray. However, given that seismic data cannot be used to distinguish between all reservoir fluids or between all lithologies, the Board agrees with the SSG that seismic data are not definitive. Therefore, the Board concludes that no changes to its requirements are necessary.

12.3.4 Drilling Density

Although the Board agrees with the SSG that additional drilling would add significantly to the identification and delineation of bitumen resources, it accepts that such data are logically collected as a preliminary step to the development of commercial bitumen projects. The Board believes that one-well-per-section drilling density is sufficient to give an indication of the geological environments consistent with a significant bitumen resource. However, it does not believe that this drilling density is sufficient to identify all significant bitumen deposits in any given area.

Similarly, the Board believes that one-well-per-section drilling density is sufficient to establish the regional geological framework and, to some degree, the nature of the separation between gas and bitumen zones. However, it does not believe that this drilling density is sufficient to assess the potential for gas to be associated with a significant bitumen resource in all cases.

The Board is willing to accept these risks, as it does not believe it is practical to mandate gas producers to drill at densities less than the normal spacing for gas wells.

12.4 Alternative Resolution Processes

The subject hearing involved 27 applications, some for approval to produce gas and others for orders to shut in gas production. It involved 66 sitting days (possibly the longest hearing ever held by the Board and its predecessors), over 800 exhibits, and about 12 000 pages of transcript. These statistics are a clear indication of the complex nature of the issues and the strongly opposing views presented and challenged during the course of the hearing. The earlier gas-bitumen inquiry and Surmont hearing were similarly long, complex, adversarial, and acrimonious. In addition, there continue to be legal challenges of the Board's decisions and its procedures.

The Board believes that the existing shared ownership regime, itself, makes resolution, whether voluntary or otherwise, extremely difficult. In these circumstances, the Board believes there are two features that make a commercial resolution of the gas/bitumen issue difficult. First, there is an absence of well-informed economic analysis. Second, under the current legislation, a Board decision either to shut in gas production or allow it to be produced has the potential to give one of the parties an advantage in negotiations.

Notwithstanding the above, and while the Board has little reason for optimism that there are voluntary alternative resolution mechanisms that would be acceptable to the parties, it believes that a serious evaluation of voluntary resolution alternatives may provide an opportunity to, if not avoid, at least simplify ongoing regulatory proceedings. The Board would encourage parties to undertake a process planning exercise with the assistance of a neutral third party to evaluate the merits of the various alternative dispute resolution options that may be available. In addition, the Board will on its own undertake to look at options to assist in the ongoing resolution of disputes relating to the gas/bitumen issue.

13 OTHER MATTERS

The Board has reviewed and considered the comments provided by the hearing participants in the Other Matters section of closing argument. To the extent necessary, the Board believes that it has addressed the issues raised by the parties in the preceding sections of the decision report.

DATED at Calgary, Alberta, on March 18, 2003.

ALBERTA ENERGY AND UTILITIES BOARD

[Original signed by]

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

[Original signed by]

C. A. Langlo, P.Geol.
Acting Board Member

[Original signed by]

W. J. Schnitzler, P.Eng.
Acting Board Member

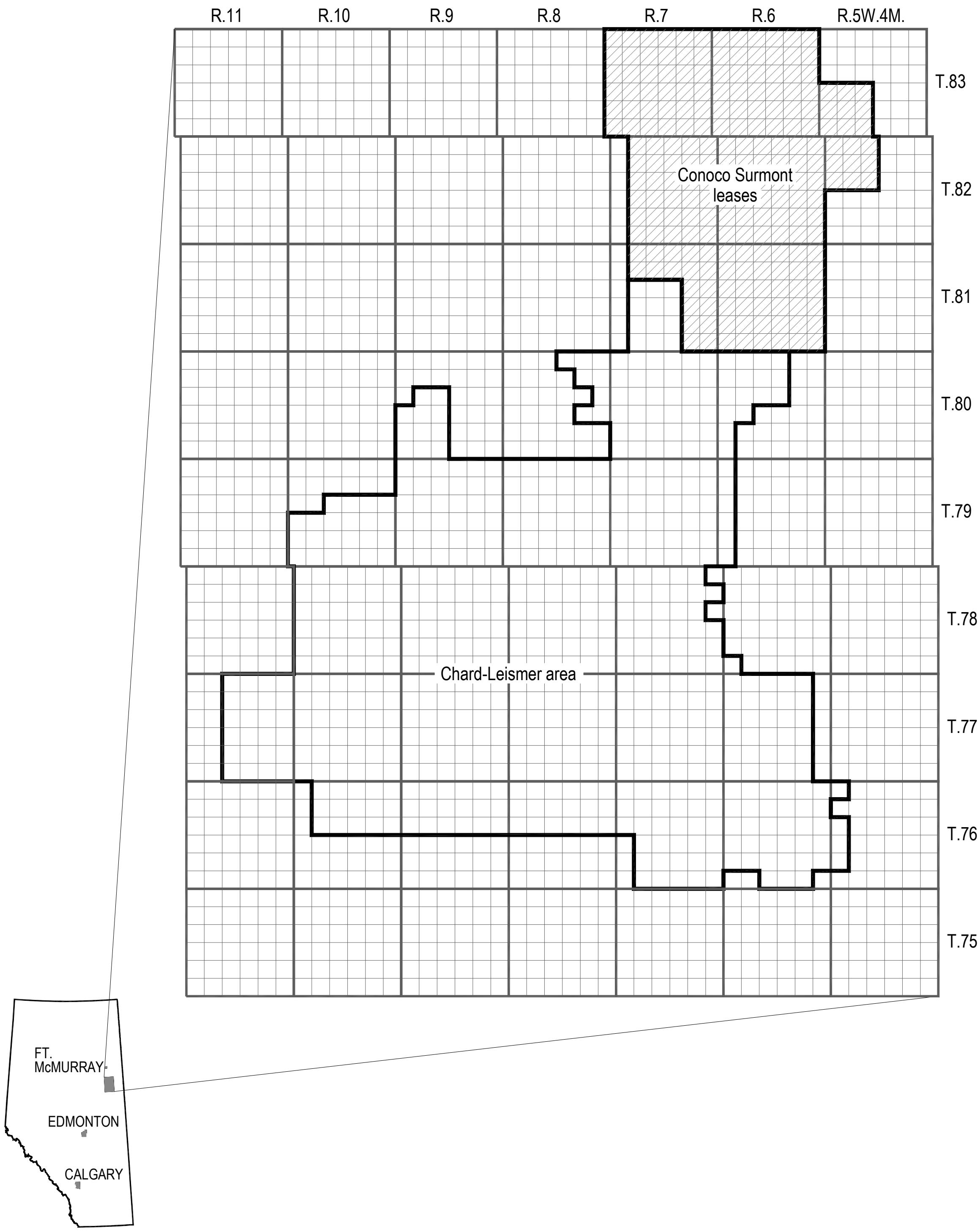
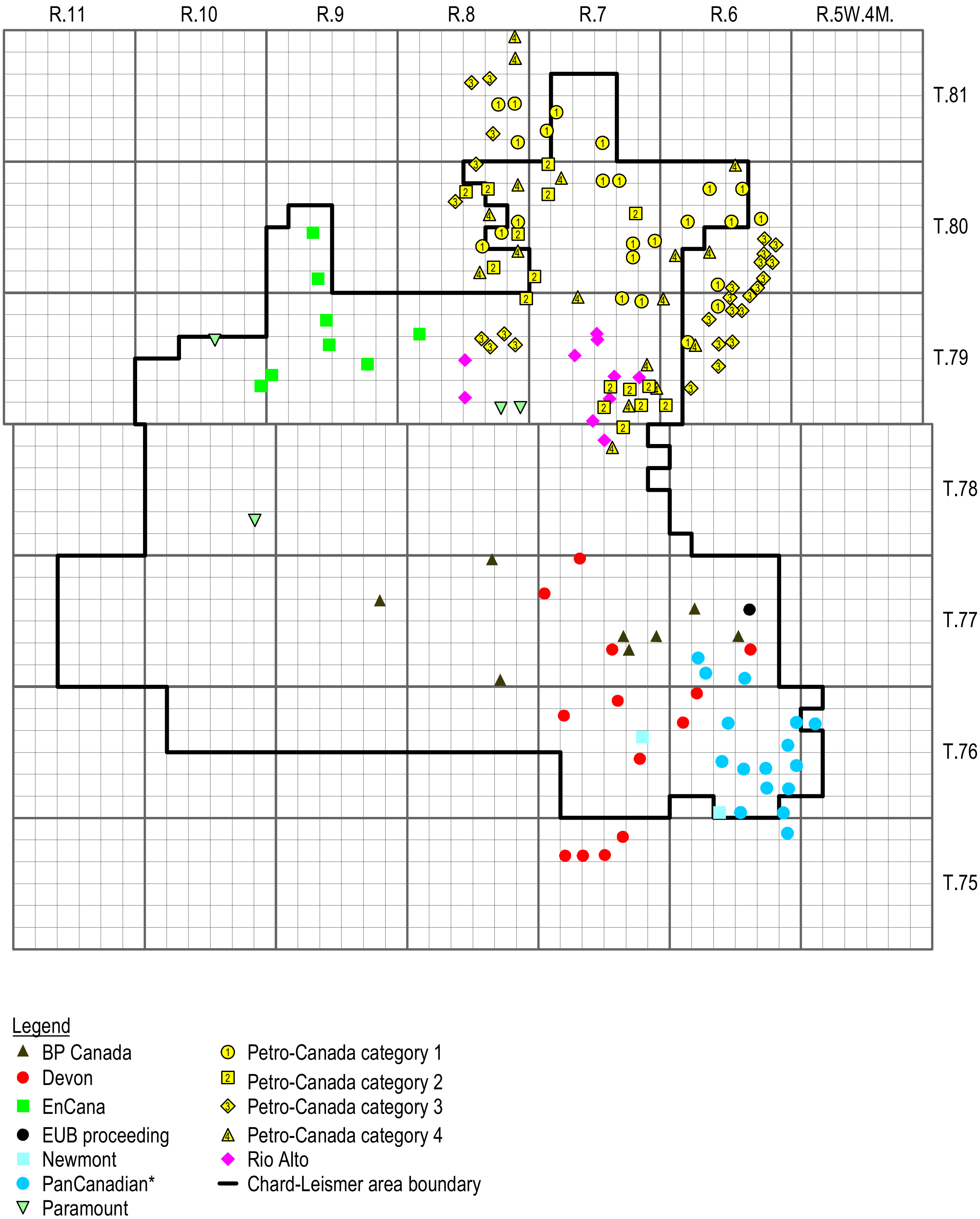


Figure 1. Chard-Leismer area and Conoco Surmont leases



* PanCanadian's application to shut in these wells was withdrawn prior to the conclusion of the hearing

Figure 2. Chard-Leismer area application wells

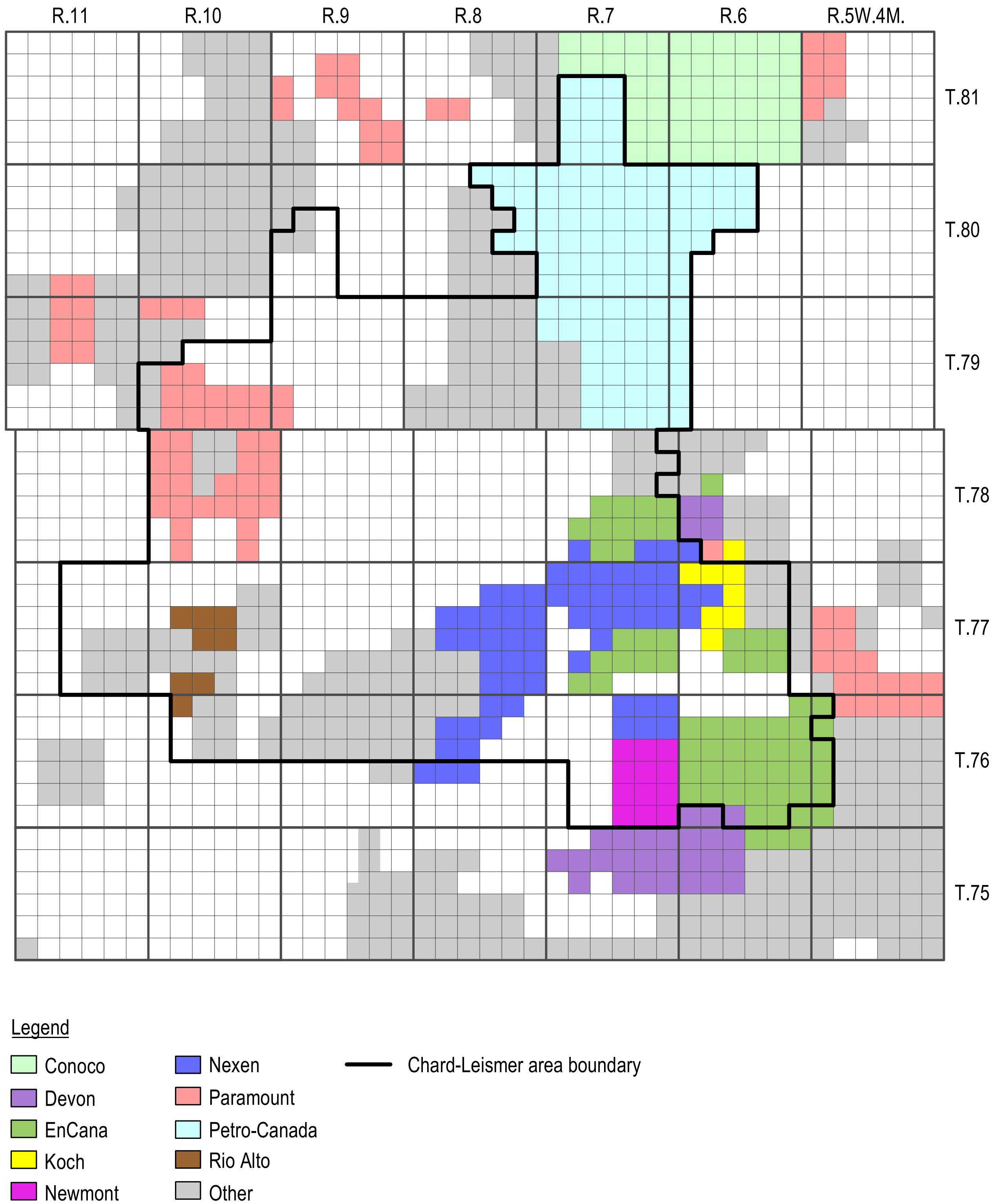


Figure 3. Chard-Leismer area oil sand leases

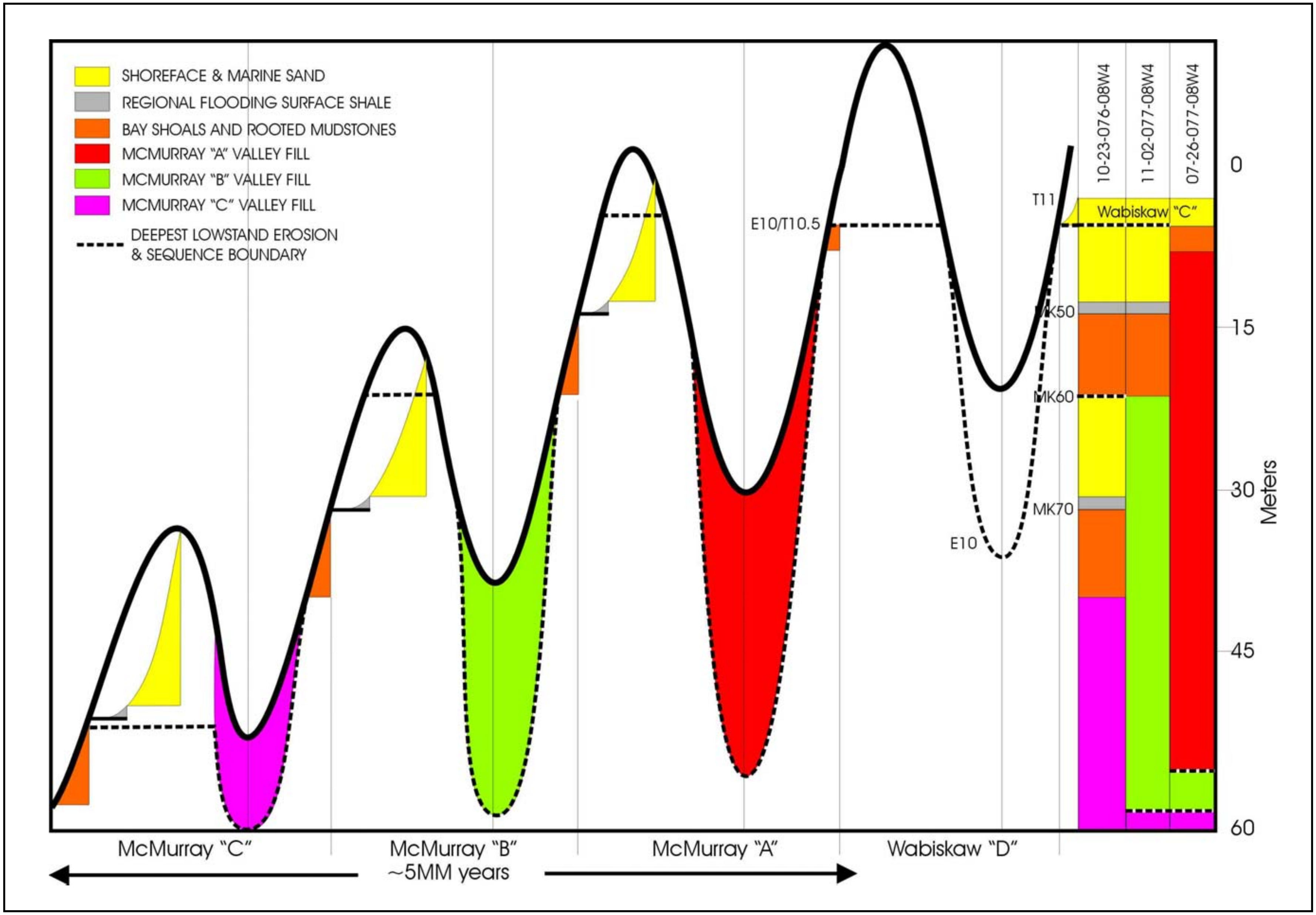


Figure 4. Relative sea level change and McMurray stratigraphy (based on Exhibit No. 999-15)

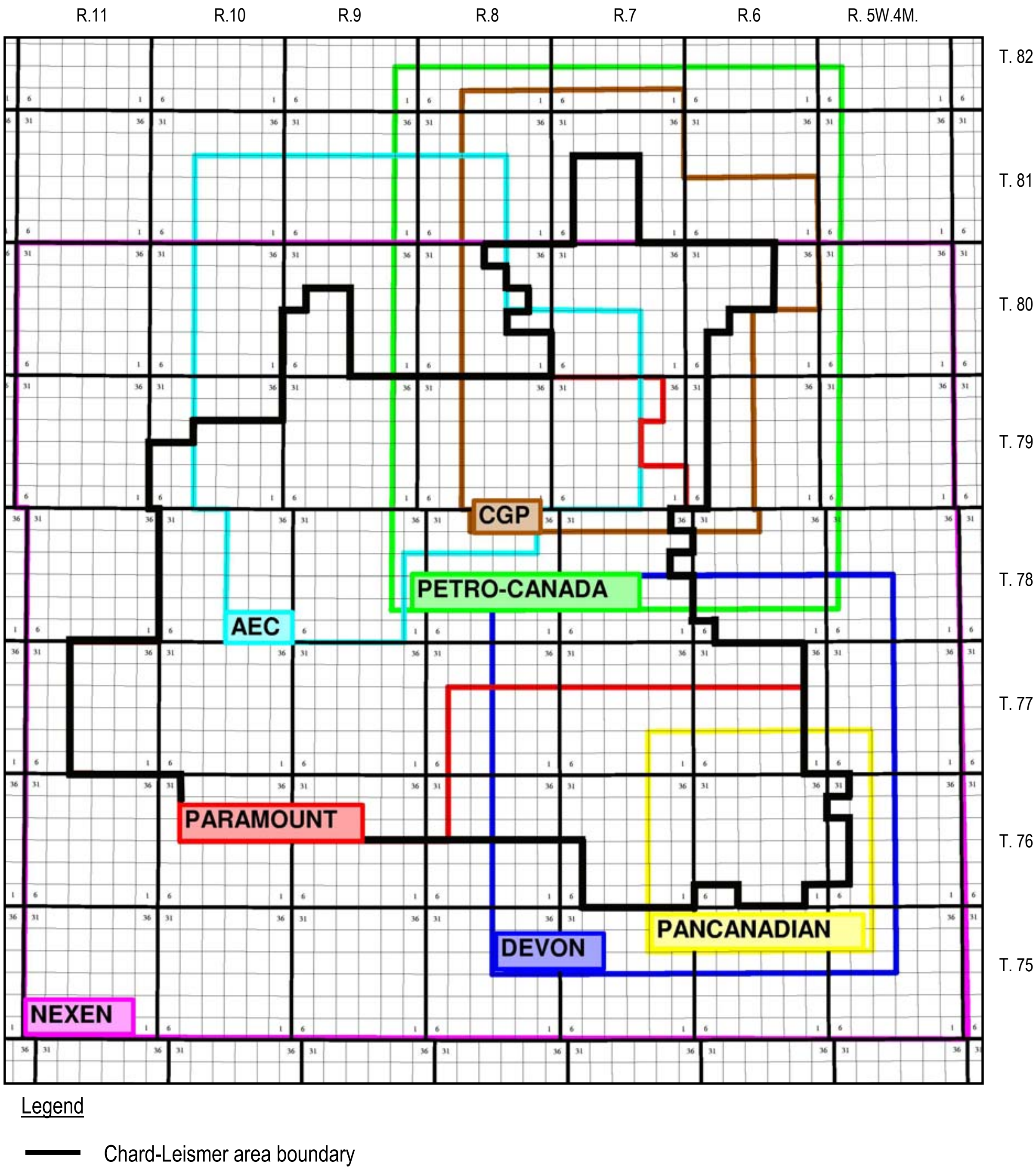


Figure 5. Areas of detailed geological mapping by hearing participants

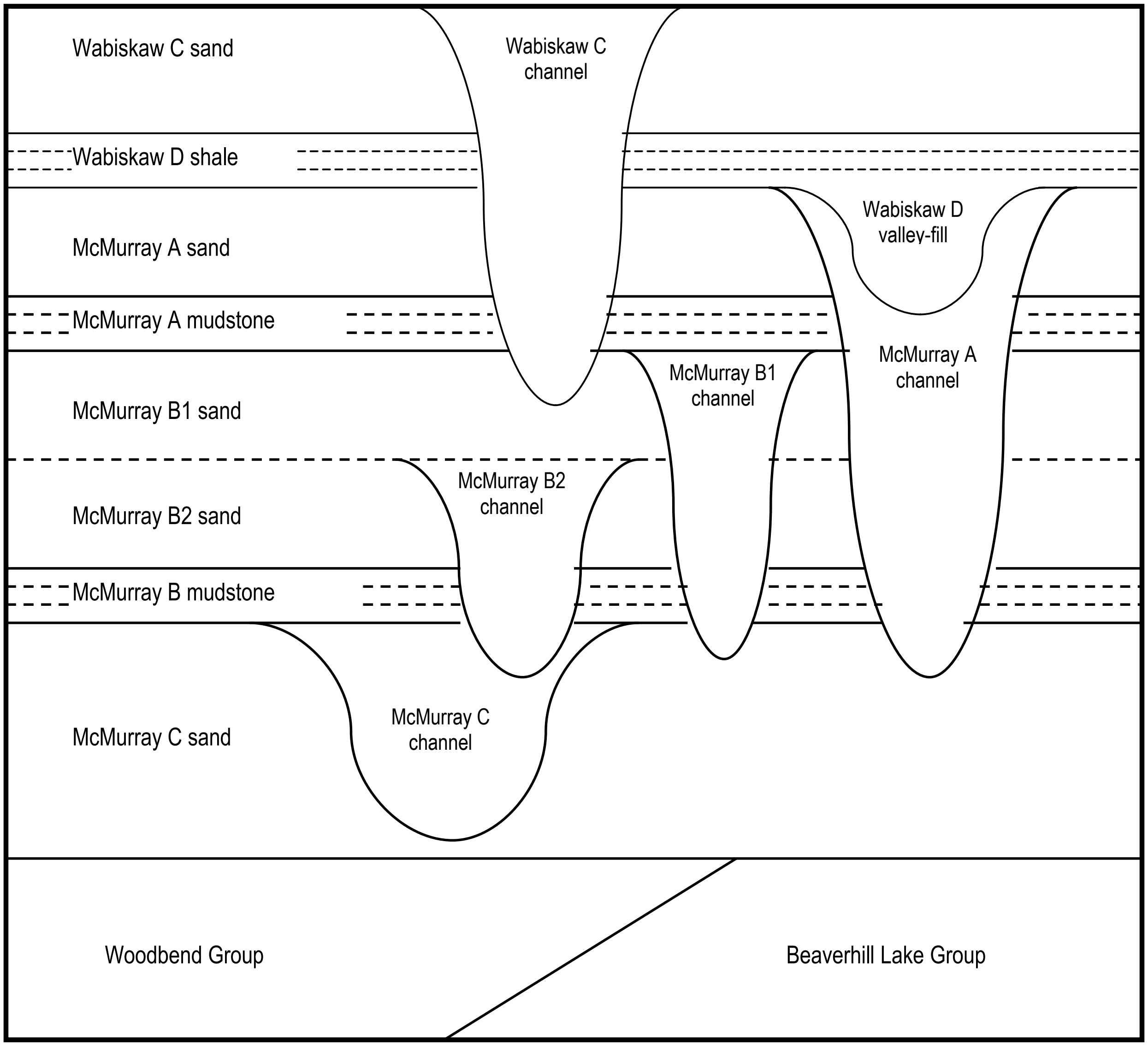


Figure 6. Wabiskaw-McMurray stratigraphy

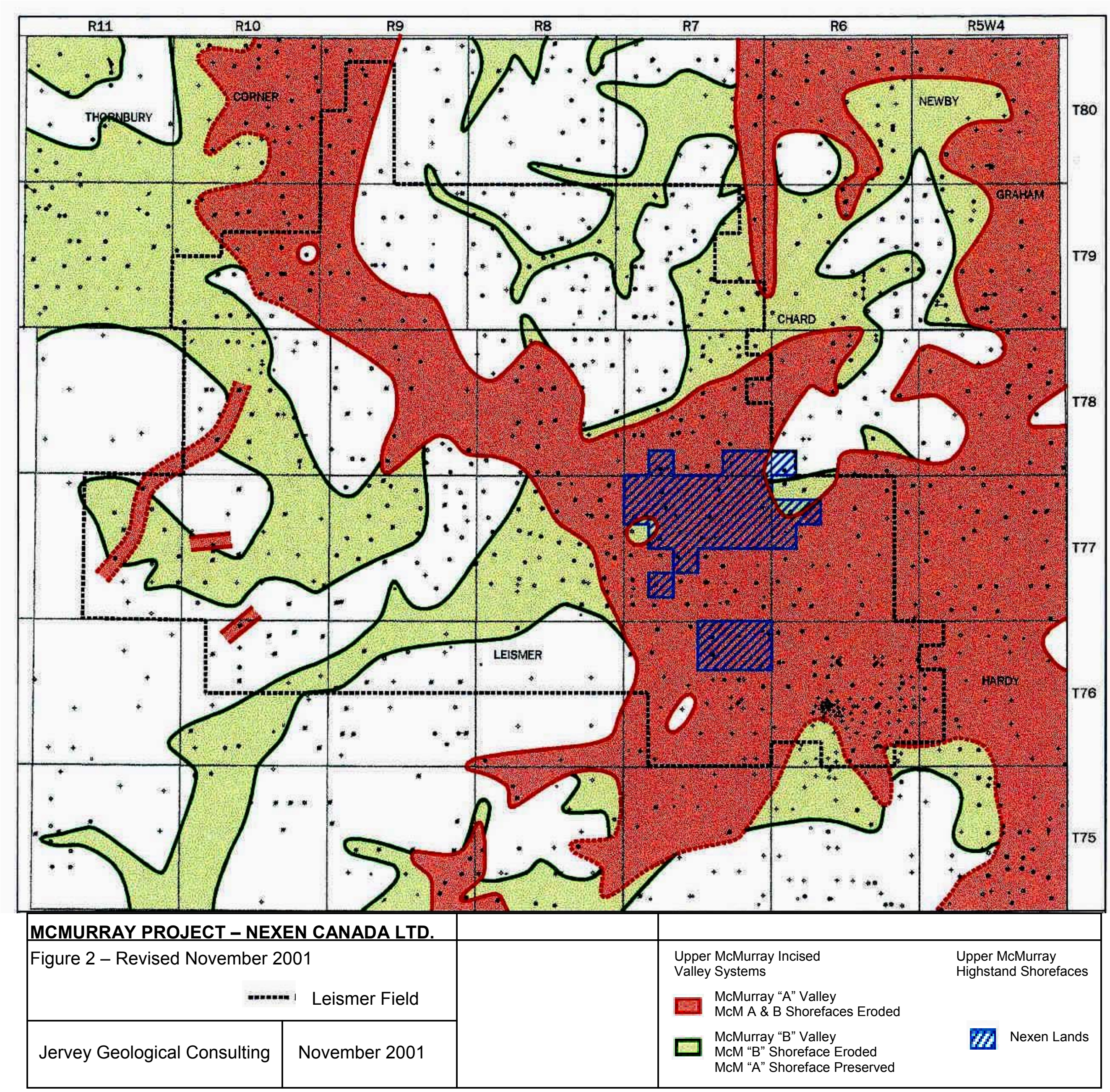
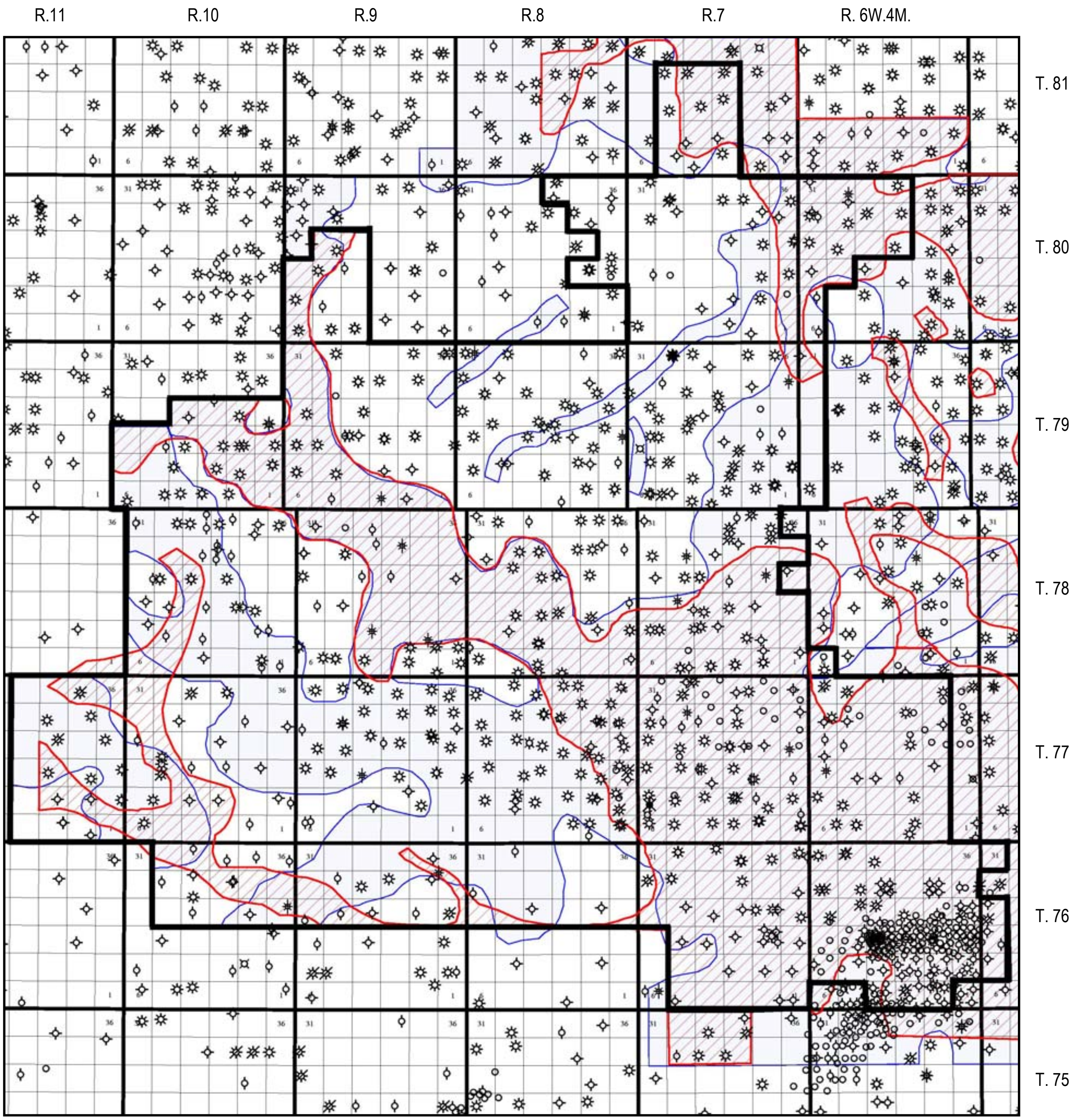


Figure 7. Nexen’s interpretation of upper McMurray incised valley sequence and highstand shorefaces (based on Exhibit No. 908)



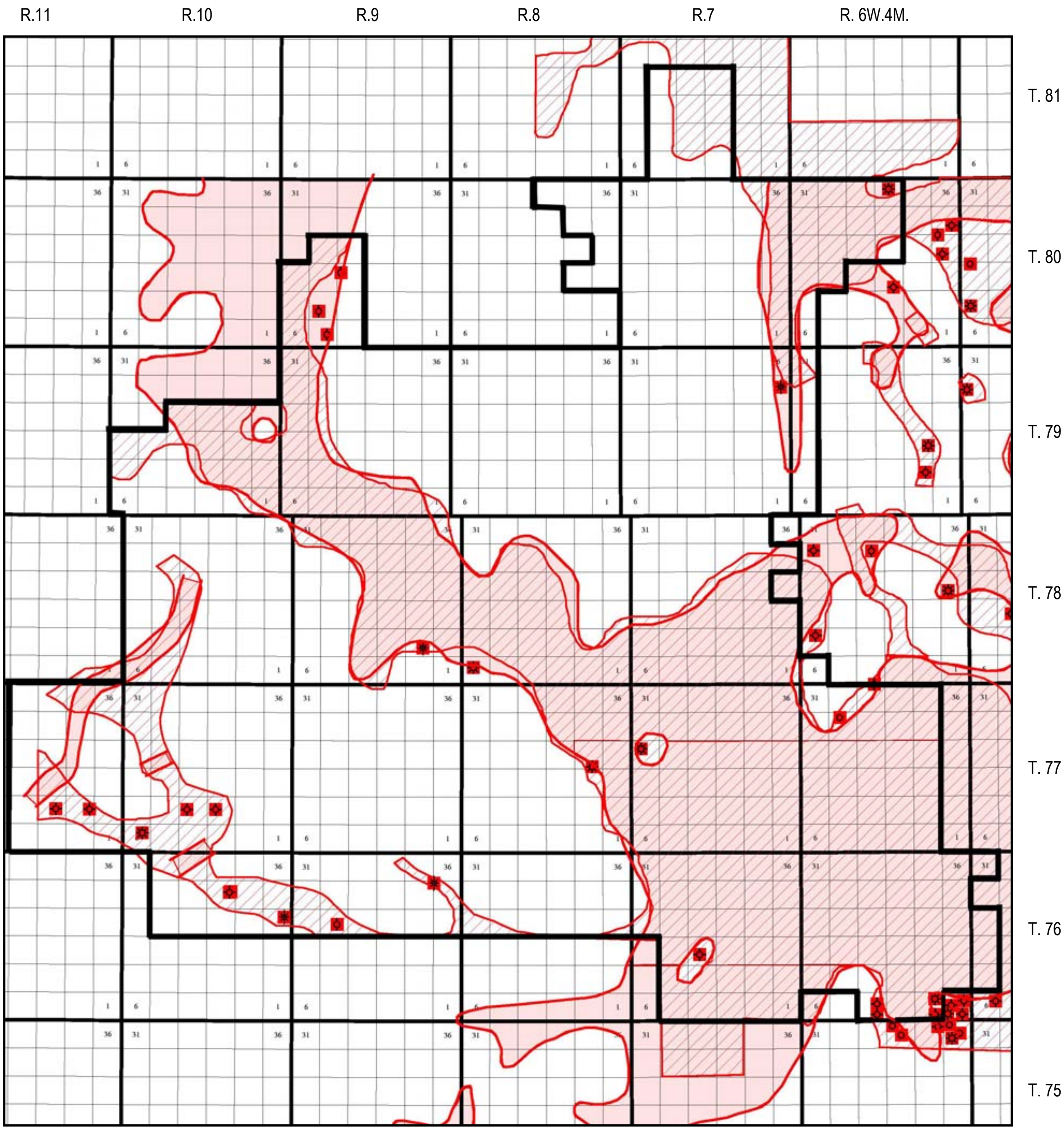
Legend

McMurray A mudstone removed by channelling

McMurray B mudstone removed by channelling

Chard-Leismer area boundary

Figure 8. Board's interpretation of areas of erosion of McMurray A and B mudstones in Chard-Leismer area



Legend

Nexen interpretation - McMurray A mudstone removed by channelling

Board interpretation - McMurray A mudstone removed by channelling

Location of disagreement

Chard-Leismer area boundary

Figure 9. Comparison of Nexen's and Board's McMurray A mudstone interpretations in Chard-Leismer area

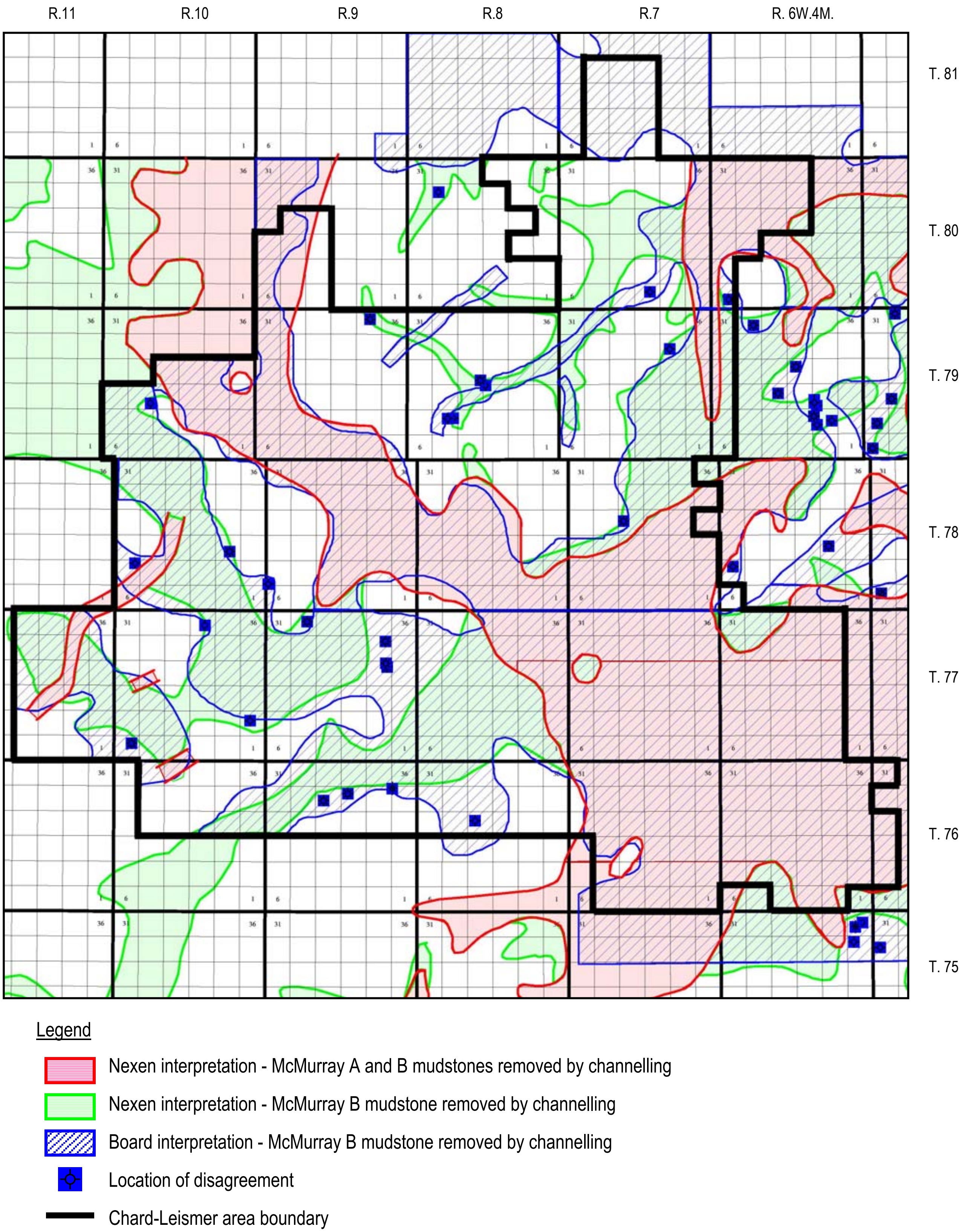


Figure 10. Comparison of Nexen's and Board's McMurray B mudstone interpretations in Chard-Leismer area

AECOG (NE) CORNER 00/12-16-080-09W4/0

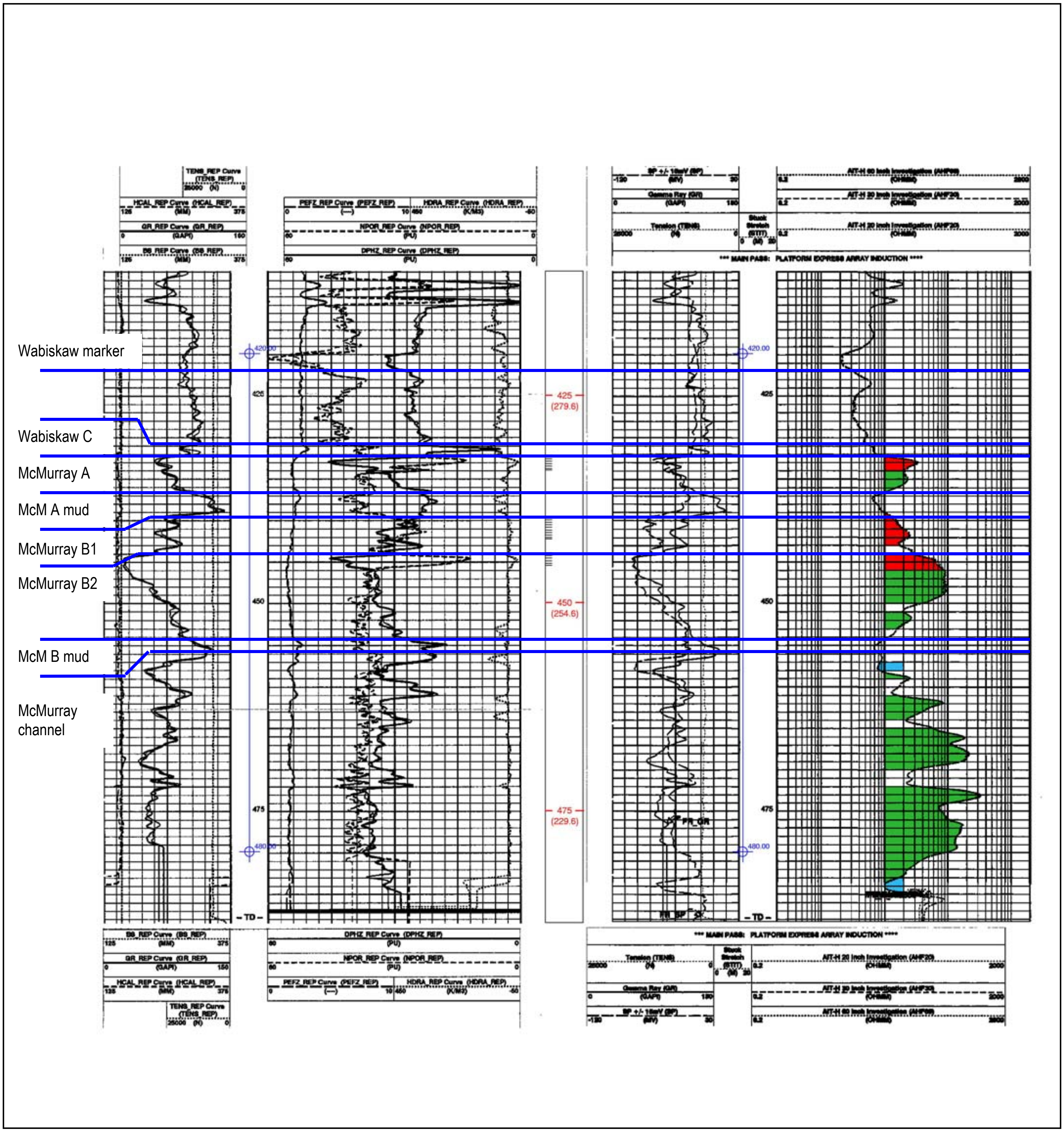


Figure 11. Type well 00/12-16-080-09W4/0

ANDERSON 4C LEISMER 00/04-01-076-06W4/0

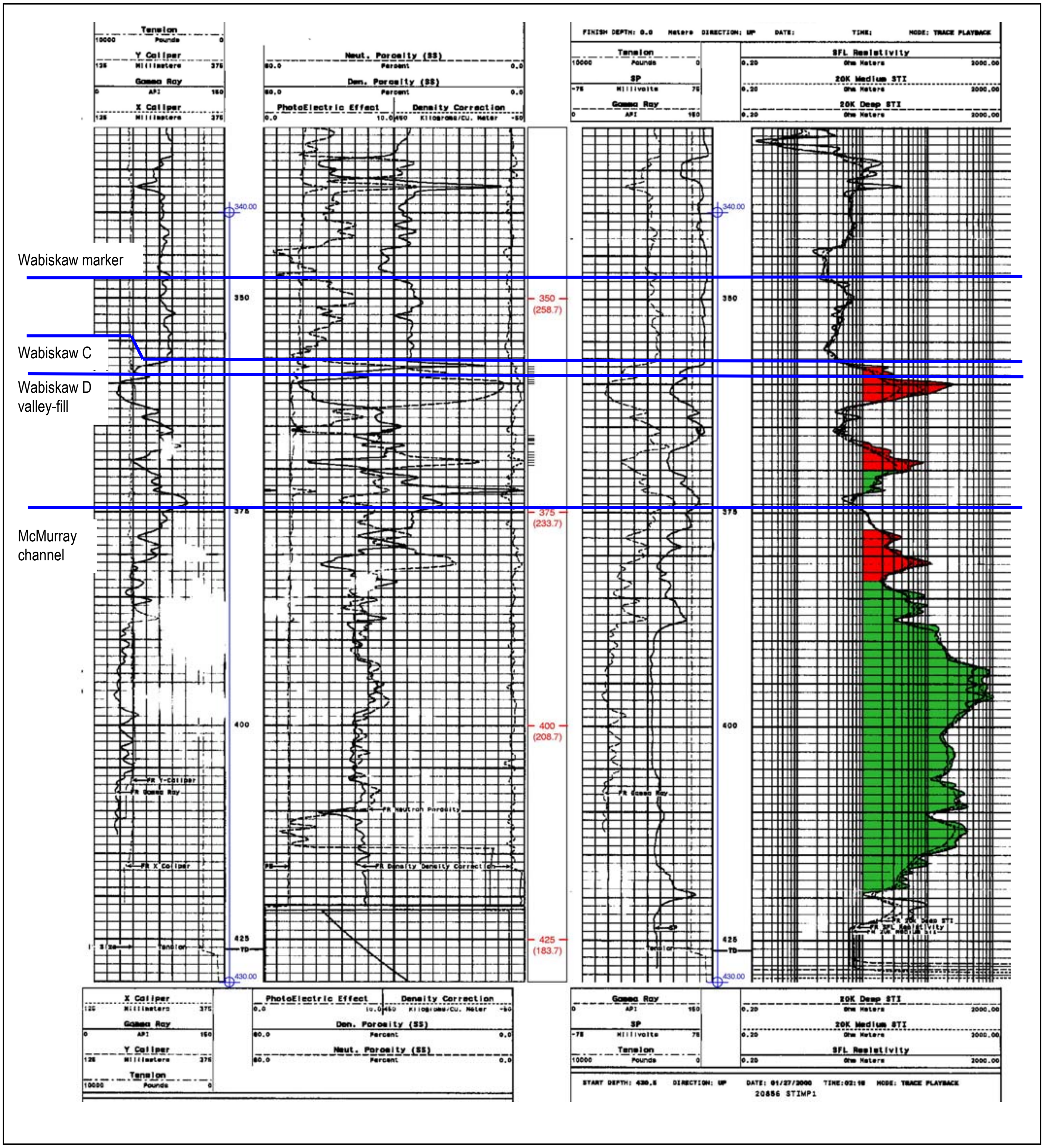


Figure 12. Type well 00/04-01-076-06W4/0

ARL LEISMER 00/04-04-076-06W4/0

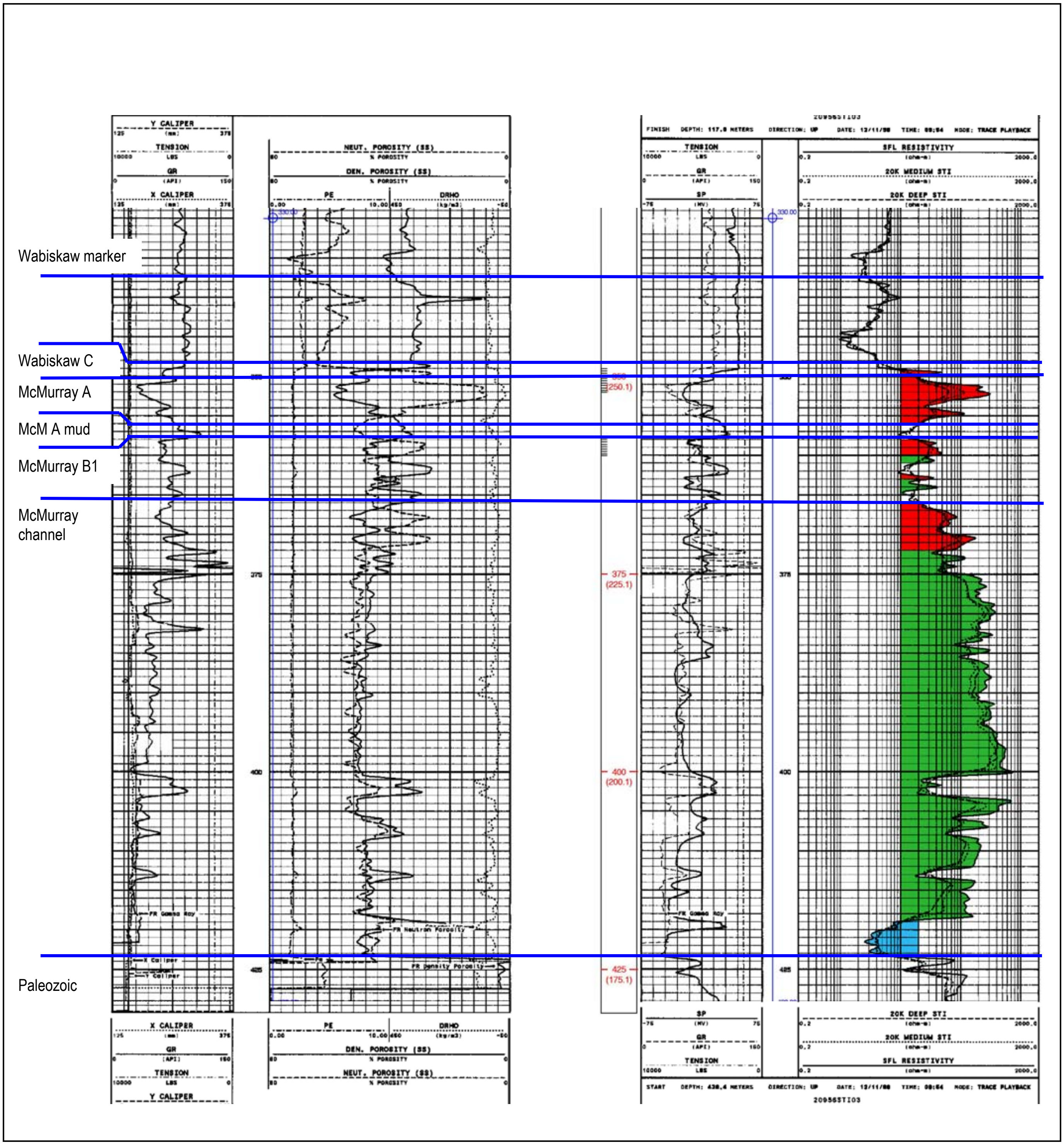


Figure 13. Type well 00/04-04-076-06W4/0

RAX ET AL CHARD 00/07-13-080-07W4/0

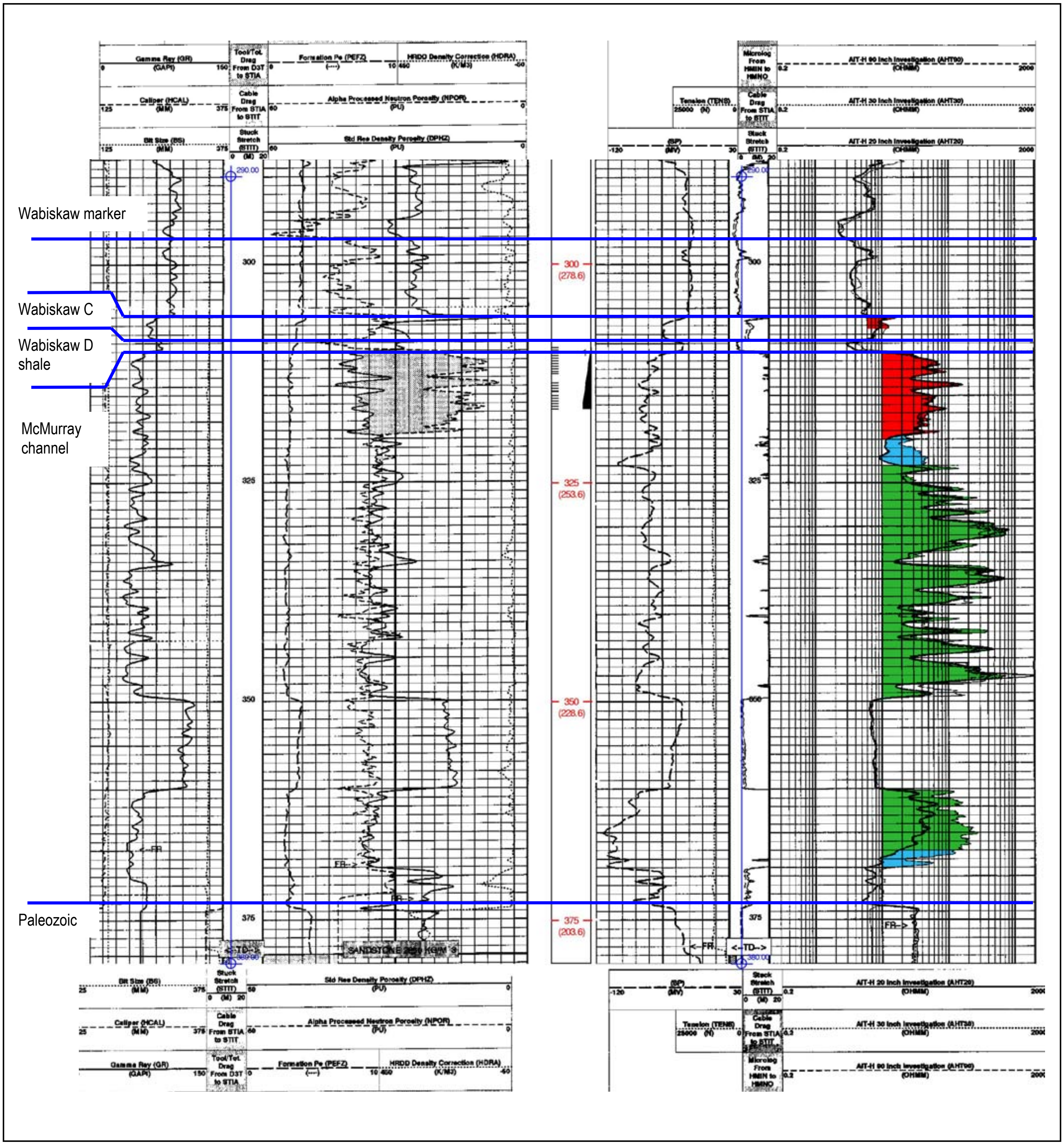


Figure 14. Type well 00/07-13-080-07W4/0

BP LEISMER 00/09-34-077-08W4/0

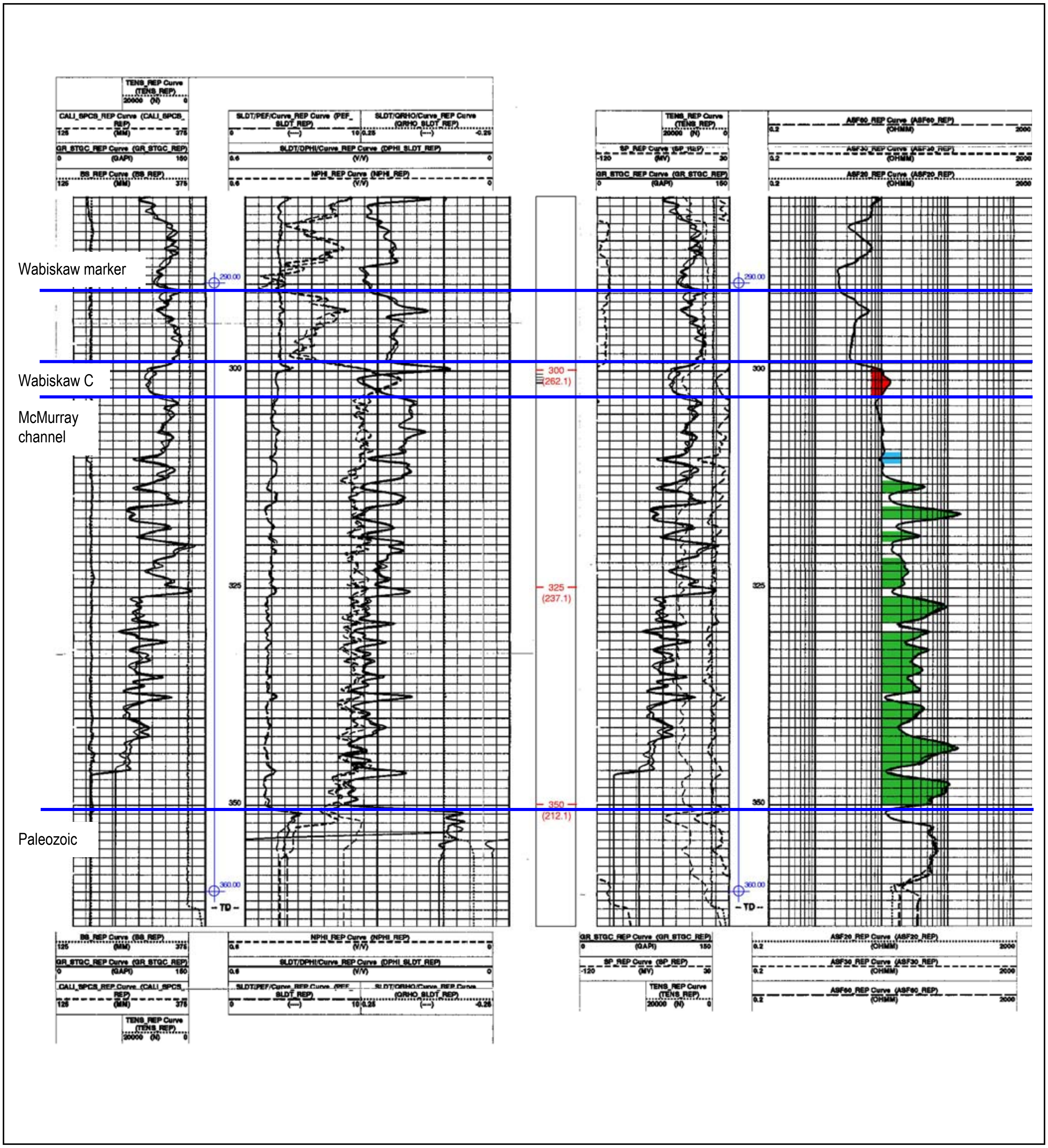


Figure 15. Type well 00/09-34-077-08W4/0

APPENDIX 1. DECISIONS ON WELLS CONSIDERED AT THE HEARING[1]

Wabiskaw-McMurray Perforated Intervals to Be Shut In

	Licensee	Unique Well ID	Wabiskaw-McMurray Interval (mKB)
1	Home	00/06-36-075-06W4/2	356.0-359.0
			362.0-363.0
			365.0-366.0
			373.0-376.0
2	Devon	00/07-30-076-05W4/0	315.0-316.0
			318.0-320.0
3	Devon	00/04-01-076-06W4/0	358.0-360.0
			366.0-367.0
			368.0-369.5
4	Devon	00/04-03-076-06W4/0	351.5-352.5
5	Devon	00/04-04-076-06W4/0	358.0-360.0
6	Home	00/06-11-076-06W4/0	338.5-339.5
			340.5-347.5
7	Home	00/06-12-076-06W4/0	345.0-352.0
8	Devon	00/08-13-076-06W4/0	341.5-347.0
9	Devon	00/06-14-076-06W4/0	317.5-318.5
			321.0-323.0
10	Devon	00/06-15-076-06W4/0	322.0-324.5
			330.5-331.0
			342.0-346.0
11	Home	00/06-24-076-06W4/0	320.5-326.0
			330.7-332.0
			338.5-343.0
12	Home	00/08-25-076-06W4/0	324.0-326.0
13	Home	00/07-28-076-06W4/2	301.1-302.1
			303.0-304.8
14	Devon	00/10-23-076-07W4/0	336.0-337.0
15	BP Canada	00/06-03-077-06W4/0	309.0-309.5
16	BP Canada	00/05-08-077-06W4/0	301.3-303.0
			303.4-305.3
17	Home	00/10-22-077-06W4/0	315.0-316.0
			317.3-319.3
18	Rio Alto	00/12-31-079-06W4/0[2]	288.0-289.5
			300.0-301.5
			302.5-303.5
19	Rio Alto	00/10-12-079-07W4/0	291.5-292.5
			295.5-297.0
20	Rio Alto	00/12-35-079-07W4/0	319.0-321.5
			348.5-350.0
21	Rio Alto	00/12-36-079-07W4/0	302.5-304.0
22	Rio Alto	00/11-24-079-08W4/2	321.0-322.0
			324.0-325.0
23	AEC	00/01-26-079-08W4/0	348.5-349.5
24	EnCana	00/10-12-079-10W4/0	393.0-394.0
25	Rio Alto	00/06-20-080-06W4/0	285.5-288.0
26	Rio Alto	00/10-27-080-06W4/0	245.7-250.2
			251.8-252.4
27	Rio Alto	00/11-28-080-06W4/2	284.0-296.0

(continued)

	Licensee	Unique Well ID	Wabiskaw-McMurray Interval (mKB)
28	Rio Alto	00/11-34-080-06W4/0	250.0-251.0
29	Rio Alto	00/07-13-080-07W4/0	309.5-312.5
			313.5-314.5
			315.0-316.5
30	Rio Alto	00/07-14-080-07W4/0	327.5-328.5
31	Northstar	00/16-03-080-08W4/0	384.5-385.5
32	Calpine	00/08-07-081-07W4/0	386.0-388.0
33	Calpine	00/06-17-081-07W4/0	385.0-386.0
34	Northstar	00/11-13-081-08W4/0	445.5-446.5
			457.5-458.5
35	Northstar	00/10-14-081-08W4/0	459.0-460.5
36	Calpine	00/11-22-081-08W4/0	444.5-447.3
			450.0-451.0
37	Calpine	00/12-23-081-08W4/0	445.0-448.0
38	Northstar	00/11-25-081-08W4/0	443.0-444.5
39	Northstar	00/11-36-081-08W4/0	446.5-448.0
			456.0-457.0

Wabiskaw-McMurray Perforated Intervals Denied for Gas Production

	Licensee	Unique Well ID	Wabiskaw-McMurray Interval (mKB)
1	Devon	00/05-27-075-07W4/0	422.0-424.0
2	Devon	00/05-28-075-07W4/0	414.5-417.5
3	Home	00/06-29-075-07W4/0	417.6-444.4[3]
4	Devon	00/01-34-075-07W4/0	389.0-390.0
5	Devon	00/07-30-076-06W4/0	304.5-305.5
6	Devon	00/12-32-076-06W4/0	305.5-307.5
			308.5-309.0
7	Devon	03/10-14-076-07W4/0	338.0-340.0
8	Devon	02/07-34-076-07W4/0	307.5-308.5
			309.5-311.5
9	Devon	00/10-10-077-06W4/0	324.0-325.0
			325.5-326.5
10	BP Canada	00/05-15-077-06W4/0	308.5-310.0
			312.9-316.5
11	BP Canada	00/12-20-077-06W4/0	306.5-309.0
12	Devon	02/11-10-077-07W4/0	305.0-306.0
			307.0-307.5
13	BP Canada	00/12-11-077-07W4/0	304.5-308.3
14	BP Canada	00/06-13-077-07W4/0	302.5-305.2
15	BP Canada	00/08-15-077-07W4/0	308.5-312.4
16	Devon	00/06-30-077-07W4/0	290.5-294.0
17	Devon	00/16-32-077-07W4/0	291.5-294.0
18	BP Canada	00/09-34-077-08W4/0	300.5-301.5
19	EnCana	00/06-18-079-09W4/0	401.0-403.0
20	EnCana	00/10-12-079-10W4/0	397.0-400.0
21	Paramount	00/15-22-079-10W4/0	423.5-425.0
			430.0-430.6

(continued)

Wabiskaw-McMurray Perforated Intervals Approved for Gas Production

	Licensee	Unique Well ID	Wabiskaw-McMurray Interval (mKB)
1	BP Canada	00/06-02-077-08W4/0	337.0-338.5
			339.5-341.0
2	BP Canada	02/15-23-077-09W4/0	333.8-335.2
			336.9-339.0
3	Rio Alto	00/05-34-078-07W4/0	282.0-283.0
			284.0-285.0
4	Paramount	00/12-12-078-10W4/0	370.3-371.0
			373.3-374.0
			385.0-385.7
5	Rio Alto	00/01-04-079-07W4/0	286.8-287.8
6	Rio Alto	00/02-10-079-07W4/0	286.5-288.0
			289.0-291.0
7	Rio Alto	00/04-13-079-07W4/0	283.0-284.0
			285.0-287.0
8	Rio Alto	00/01-15-079-07W4/0	292.5-293.5
			295.0-297.0
9	Rio Alto	00/04-21-079-07W4/0	308.0-309.0
			310.5-312.0
10	Rio Alto	00/12-22-079-07W4/0	311.5-312.5
11	Rio Alto	00/04-27-079-07W4/0	304.0-305.0
			306.5-307.5
12	Rio Alto	00/10-01-079-08W4/0	295.0-296.0
			298.0-299.0
			305.3-306.3
			309.0-310.0
13	Rio Alto	00/10-02-079-08W4/0	299.6-300.3
			302.5-303.5
14	Rio Alto	00/04-10-079-08W4/0	319.5-320.5
15	Rio Alto	00/13-15-079-08W4/0	336.0-337.5
			339.0-340.5
16	EnCana	00/04-29-079-08W4/0	372.2-373.2
			374.5-375.5
			382.8-385.0
17	EnCana	00/10-14-079-09W4/0	410.5-411.0
			412.5-413.5
18	EnCana	00/09-21-079-09W4/0	411.5-413.0
19	EnCana	00/10-28-079-09W4/0	409.0-410.5
			412.0-412.5
			417.0-418.5
			420.0-421.0
			422.0-423.5
20	EnCana	00/11-04-080-09W4/0	426.5-429.5
			434.5-439.0
			440.5-441.5
21	EnCana	00/12-16-080-09W4/0	432.3-434.0
			440.0-442.3
			444.0-445.5

(continued)

Wabiskaw-McMurray Perforated Intervals Not Required to Be Shut In

	Licensee	Unique Well ID	Wabiskaw-McMurray Interval (mKB)
1	Devon	00/04-04-076-06W4/0	348.0-352.0
2	Home	00/11-16-076-06W4/0	318.5-321.5[4]
3	Home	00/10-05-077-06W4/2	366.4-368.2
			371.9-373.7
4	Rio Alto	00/13-27-078-07W4/0	283.0-284.3
5	Rio Alto	00/16-34-078-07W4/0	281.0-282.0
			283.0-284.5
6	Rio Alto	00/11-06-079-06W4/0	292.0-295.0
7	Rio Alto	00/11-08-079-06W4/0	244.0-248.0
8	Rio Alto	00/10-16-079-06W4/0	230.5-233.0
			234.0-237.0
9	Rio Alto	00/11-20-079-06W4/0	274.9-279.2
10	Rio Alto	02/11-20-079-06W4/0[2]	279.5-285.3
			321.3-321.6
11	Rio Alto	00/10-21-079-06W4/0	217.0-223.5
12	Paramount	00/11-22-079-06W4/0	221.6-223.7
			226.5-227.7
13	Rio Alto	00/11-28-079-06W4/0	250.5-257.0
			260.0-261.0
14	Rio Alto	00/07-32-079-06W4/0	286.0-290.5
			291.0-292.5
15	Paramount	00/06-34-079-06W4/0	Perforations Abandoned
16	Paramount	02/06-34-079-06W4/2	235.5-237.3
			246.0-247.5
17	Paramount	00/13-34-079-06W4/0	242.0-247.5
18	Paramount	00/13-35-079-06W4/0	236.0-241.0
19	Rio Alto	00/13-01-079-07W4/0	289.0-290.0
			291.0-292.0
20	Rio Alto	00/11-02-079-07W4/0	No Perforations
21	Rio Alto	00/11-03-079-07W4/0	286.5-287.5
			288.5-290.0
22	Rio Alto	00/10-10-079-07W4/0	291.0-293.0
23	Rio Alto	00/10-11-079-07W4/0	282.0-283.5
			284.5-288.5
24	Rio Alto	00/09-12-079-07W4/0	No Perforations
25	Rio Alto	00/10-12-079-07W4/0	283.0-285.0
26	Rio Alto	00/11-13-079-07W4/0	269.0-270.6
			271.0-271.5
27	Rio Alto	00/11-33-079-07W4/0	320.5-321.8
28	Rio Alto	00/12-36-079-07W4/0	290.0-292.0
29	Rio Alto	00/16-22-079-08W4/2	346.5-347.5
			348.5-349.5
			357.0-358.5
30	Rio Alto	00/12-23-079-08W4/2	332.0-333.5
			335.0-336.0
31	Rio Alto	00/11-24-079-08W4/2	309.8-311.0
32	AEC	00/01-26-079-08W4/0	338.0-339.0
			340.5-341.5
33	AEC	00/10-36-079-08W4/0	333.5-334.7
			336.0-337.3
			344.0-345.0
			346.8-348.8

(continued)

	Licensee	Unique Well ID	Wabiskaw-McMurray Interval (mKB)
34	Rio Alto	00/03-02-080-06W4/0	237.0-241.0
35	Rio Alto	00/10-02-080-06W4/0	236.0-238.0
36	Rio Alto	00/03-03-080-06W4/0	249.5-253.0
37	Rio Alto	00/07-04-080-06W4/0	293.0-299.0
			304.0-305.0
38	Rio Alto	00/10-07-080-06W4/0	295.4-299.6
			302.4-303.9
			305.4-307.8
			309.4-315.2
39	Rio Alto	00/11-09-080-06W4/0	305.5-311.0
			316.0-317.0
40	Rio Alto	00/09-11-080-06W4/0	222.0-223.0
			224.5-229.0
			232.0-233.0
41	Rio Alto	00/15-11-080-06W4/0	227.3-233.0
			236.0-237.3
42	Paramount	00/05-12-080-06W4/0	208.5-209.5
			211.0-215.0
			219.0-221.0
43	Paramount	00/04-13-080-06W4/0	213.5-214.5
			215.5-220.0
			223.0-226.5
44	Rio Alto	00/07-14-080-06W4/0	240.0-245.0
			247.5-249.0
45	Rio Alto	00/06-22-080-06W4/0	309.5-313.5
46	Rio Alto	00/07-23-080-06W4/0	250.5-253.5
47	Rio Alto	00/11-28-080-06W4/2	280.0-281.0
48	Rio Alto	00/11-34-080-06W4/0	238.0-240.0
			242.0-244.5
49	Northstar	00/11-06-080-07W4/0	351.5-352.5
			355.0-356.0
50	Rio Alto	00/10-11-080-07W4/0	315.1-319.0
51	Rio Alto	00/07-14-080-07W4/0	319.5-321.0
52	Rio Alto	00/10-23-080-07W4/0	315.5-319.0
53	Calpine	00/08-30-080-07W4/0	355.5-357.0
			359.0-359.5
			365.5-367.0
54	Northstar	00/16-31-080-07W4/0	363.0-364.0
			369.0-369.5
55	Northstar	02/03-32-080-07W4/0	359.0-361.0
			365.0-366.0
			367.0-368.0
56	Calpine	00/03-34-080-07W4/0	331.0-332.0
			334.5-337.0
			340.5-341.0
			344.5-346.5
57	Calpine	00/04-35-080-07W4/0	315.0-316.0
			319.5-322.0
			325.0-327.0
			328.0-329.0
			331.5-333.0

(continued)

	Licensee	Unique Well ID	Wabiskaw-McMurray Interval (mKB)
58	Paramount	00/03-11-080-08W4/0	353.0-354.0
			355.0-356.0
			356.0-357.0
			363.0-365.0
			366.0-368.0
59	Paramount	00/14-12-080-08W4/0	367.0-368.0
			370.3-371.3
60	Northstar	00/11-13-080-08W4/0	357.5-358.5
			365.0-366.0
			367.0-367.5
			369.0-370.0
61	Northstar	02/10-14-080-08W4/0	375.5-378.0
			379.5-380.5
62	Northstar	00/01-15-080-08W4/0	382.0-383.0
63	Northstar	00/05-23-080-08W4/0	379.5-380.5
			386.0-387.0
			389.0-391.0
64	Northstar	00/03-24-080-08W4/0	362.3-365.3
65	Northstar	00/14-25-080-08W4/0	386.0-387.0
			393.0-394.0
66	Northstar	00/12-26-080-08W4/0	395.5-397.5
			402.0-403.0
67	Northstar	00/12-27-080-08W4/0	392.0-393.0
			399.0-400.0
			400.5-401.5
68	Northstar	00/02-28-080-08W4/0	412.0-414.5
69	Northstar	00/15-34-080-08W4/0	429.0-430.0
70	Calpine	00/14-03-081-07W4/0	347.0-350.0
			352.5-354.5
			356.0-358.0
71	Calpine	00/08-07-081-07W4/0	377.5-378.5
			381.0-382.5
72	Calpine	00/06-17-081-07W4/0	378.5-381.0
73	Northstar	00/14-01-081-08W4/0	399.0-400.3
74	Northstar	00/06-11-081-08W4/0	440.0-442.5
75	Northstar	00/11-13-081-08W4/0	440.0-441.0
76	Northstar	00/10-14-081-08W4/0	451.0-451.5
			453.0-454.0

1 Thirteen wells appear twice in the following tables.
2 Abandoned well.
3 DST interval.
4 Although the Board interprets this to be a high-risk gas zone, it is not being shut in since EnCana and Devon have proposed to repressure this zone (see Section 8).

APPENDIX 2. ANNUAL RESOURCE MANAGEMENT REPORT

1. Reporting Requirement

For Petro-Canada, Newmont, EnCana, and Nexen to annually report on the management of the resources on their oil sands leases in the Chard-Leismer area, including an assessment of the effect that the pressure of the overlying gas zone has on the recovery of bitumen by SAGD.

2. Reporting Period and Filing Date

Initial reporting period: April 1 to December 31, 2003
Initial filing date: March 31, 2004 (2 copies)

Subsequent annual reporting period: January 1 to December 31
Subsequent annual filing date: March 31 (2 copies)

3. Report Content

The report will consist of the following three sections:

- Experimental Scheme – This section will include confidential data and information from any future experimental scheme. It will be held confidential until expiry of the confidentiality term for the scheme, after which it will be publicly available.

- Commercial Scheme – This section will include nonconfidential data and information from any future commercial scheme. It will be publicly available.

- Other Information and Data – This section will include nonconfidential data and information not specifically related to a commercial scheme. It will be publicly available.

Experimental Scheme and Commercial Scheme Sections

1. Drilling and Completions
    - Well layout/location map, including any new wells
    - For experimental scheme, well completions and workovers, including wellbore schematics. For commercial scheme, typical wellbore schematics for injection and production wells.

2. Facilities
    - Detailed site survey plan, including modifications
    - Plant schematic, including modifications

3. Instrumentation in Wells
    - For experimental scheme, thermocouples and piezometers installed in wells, including wellbore schematics. For commercial scheme, thermocouples and piezometers installed in wells, including typical wellbore schematics.
    - Lateral and vertical position of thermocouples and piezometers installed in observation wells relative to well pairs
    - Piezometer plots, including supporting data points in tabular form
    - Thermocouple plots, including supporting data points in tabular form
    - Temperature logs
    - Other well test data and analyses

4. Scheme Performance
    - Injection and production history
        - Plots on a composite and individual well-pair basis for steam injection rates, bitumen and water production rates, steam oil ratio, and other injected/produced fluid rates
        - Quality of steam injected, including the temperature and pressure
        - Composition of other injected/produced fluids
    - Comparison of predicted versus actual performance

5. Artificial Lift
    - Type of artificial lift used for each well pair
    - Artificial lift performance

6. 3-D/4-D Seismic
    - Seismic lines location map
    - Interpreted results from seismic surveys

7. Geology
    - Composite well logs over Wabiskaw-McMurray interval
    - Identify cored wells and any special core analyses conducted
    - Petrographic analyses
    - For experimental scheme, structural cross-section for each well pair. For commercial scheme, representative structural cross-section for scheme area.
    - Surface and subsurface geomechanical data and analyses

8. Interpretations and Conclusions
    Interpretations and conclusions on the basis of the collected data, including
        - extent of steam chamber development for each well pair
        - effect that the pressure of the overlying gas zone has on bitumen recovery
        - ability to lift fluids at low operating pressures
        - overall success of the scheme

Other Information and Data Section

1. Drilling and Completions
    - Evaluation and infill wells, including a location map

2. Instrumentation in Wells
    - Piezometers installed in wells, including wellbore schematics
    - Piezometer plots, including supporting data points in tabular form
    - Other well test data and analyses

3. Geology
    - Composite well logs over Wabiskaw-McMurray interval from evaluation and infill wells
    - Identify cored wells and any special core analyses conducted
    - Petrographic analyses

4. Interpretations and Conclusions
    Interpretations and conclusions on the basis of the collected data, including updated resource and region of influence maps for the oil sands leases

APPENDIX 3. ADDITIONAL WELLS THAT COULD PRESENT A RISK TO FUTURE BITUMEN RECOVERY IN THE CHARD-LEISMER AREA

Grandfathered Wells

	Licensee	Unique Well ID
1	Home	00/10-14-076-07W4/0
2	Paramount	00/06-24-076-09W4/0
3	Paramount	00/11-29-076-09W4/0
4	Paramount	00/09-27-076-10W4/0
5	Paramount	00/03-28-076-10W4/0
6	Paramount	00/11-29-076-10W4/0
7	Paramount	00/14-33-076-10W4/0
8	Devon	00/10-19-077-06W4/0
9	Home	00/11-27-077-06W4/0
10	Home	00/10-31-077-06W4/0
11	Home	00/06-32-077-06W4/0
12	Superman	00/07-35-077-06W4/0
13	Home	00/11-17-077-07W4/0
14	Home	00/11-01-077-08W4/0
15	BP Canada	02/11-01-077-08W4/0
16	BP Canada	00/07-14-077-08W4/0
17	BP Canada	00/10-16-077-08W4/0
18	BP Canada	00/12-21-077-08W4/0
19	BP Canada	00/07-26-077-08W4/2
20	BP Canada	00/10-32-077-08W4/0
21	BP Canada	00/11-36-077-08W4/0
22	BP Canada	00/08-13-077-09W4/0
23	BP Canada	00/07-15-077-09W4/0
24	BP Canada	00/12-17-077-09W4/0
25	BP Canada	00/15-26-077-09W4/0
26	BP Canada	00/10-33-077-09W4/0
27	BP Canada	00/07-34-077-09W4/0
28	BP Canada	00/10-35-077-09W4/0
29	BP Canada	00/06-36-077-09W4/0
30	Paramount	00/10-06-077-10W4/0
31	Paramount	00/09-07-077-10W4/0
32	Paramount	00/11-16-077-10W4/0
33	Paramount	00/03-20-077-10W4/0
34	Paramount	00/06-33-077-10W4/0
35	Paramount	00/09-12-077-11W4/0
36	Paramount	00/09-13-077-11W4/0
37	Paramount	00/08-14-077-11W4/0
38	Paramount	00/11-15-077-11W4/0
39	Paramount	00/10-22-077-11W4/0
40	Paramount	00/11-24-077-11W4/0
41	Paramount	00/09-26-077-11W4/0
42	Paramount	00/05-27-077-11W4/0
43	Paramount	00/06-35-077-11W4/0
44	Home	00/02-06-078-06W4/0

Grandfathered Wells

	Licensee	Unique Well ID
45	Devon	00/11-02-078-07W4/0
46	BP Canada	00/07-04-078-07W4/0
47	Rio Alto	00/05-22-078-07W4/0
48	Rio Alto	00/15-26-078-07W4/0
49	Rio Alto	00/07-35-078-07W4/0
50	Paramount	00/03-09-078-08W4/0
51	Paramount	00/02-16-078-08W4/0
52	Paramount	00/02-17-078-08W4/0
53	Paramount	00/15-20-078-08W4/0
54	Paramount	00/12-22-078-08W4/0
55	Paramount	00/11-23-078-08W4/0
56	Paramount	00/11-26-078-08W4/0
57	Paramount	00/09-27-078-08W4/0
58	Paramount	00/09-34-078-08W4/0
59	Paramount	00/11-36-078-08W4/0
60	BP Canada	00/11-05-078-09W4/0
61	BP Canada	00/09-06-078-09W4/0
62	BP Canada	00/01-10-078-09W4/0
63	AEC	00/12-19-078-09W4/0
64	Paramount	00/11-22-078-09W4/0
65	AEC	00/07-29-078-09W4/0
66	Paramount	00/07-33-078-09W4/0
67	BP Canada	00/06-01-078-10W4/0
68	Paramount	00/09-02-078-10W4/0
69	Paramount	00/06-08-078-10W4/0
70	Paramount	00/08-16-078-10W4/0
71	Paramount	00/08-19-078-10W4/0
72	Paramount	00/05-20-078-10W4/0
73	Paramount	00/06-31-078-10W4/0
74	Paramount	00/05-33-078-10W4/0
75	Paramount	00/06-34-078-10W4/0
76	Paramount	00/06-36-078-10W4/0
77	Rio Alto	00/12-05-079-07W4/0
78	Rio Alto	00/09-07-079-07W4/0
79	Rio Alto	00/11-08-079-07W4/0
80	Rio Alto	00/03-09-079-07W4/0
81	Rio Alto	00/09-18-079-07W4/0
82	Rio Alto	00/09-19-079-07W4/0
83	AEC	00/04-30-079-07W4/0
84	AEC	00/07-07-079-08W4/0
85	Paramount	00/11-11-079-08W4/0
86	Rio Alto	00/11-15-079-08W4/0
87	Rio Alto	00/11-16-079-08W4/0
88	AEC	00/10-18-079-08W4/0

(continued)

Grandfathered Wells

	Licensee	Unique Well ID
89	AEC	00/03-20-079-08W4/0
90	Rio Alto	00/03-22-079-08W4/0
91	AEC	00/03-28-079-08W4/0
92	AEC	00/12-30-079-08W4/0
93	AEC	00/09-32-079-08W4/0
94	AEC	00/11-35-079-08W4/0
95	AEC	00/08-08-079-09W4/0
96	AEC	00/08-13-079-09W4/0
97	AEC	00/11-15-079-09W4/0
98	AEC	00/11-16-079-09W4/0
99	AEC	00/05-17-079-09W4/0
100	AEC	00/08-19-079-09W4/0
101	AEC	00/11-27-079-09W4/0
102	AEC	00/09-32-079-09W4/0
103	AEC	00/10-35-079-09W4/0
104	AEC	00/09-36-079-09W4/0
105	Paramount	00/12-02-079-10W4/0
106	Paramount	00/07-06-079-10W4/0
107	AEC	00/07-13-079-10W4/0
108	Paramount	00/06-14-079-10W4/0
109	Paramount	00/07-14-079-10W4/0
110	Paramount	00/08-15-079-10W4/0
111	Paramount	00/02-16-079-10W4/0
112	Paramount	00/01-17-079-10W4/0
113	Paramount	00/06-23-079-10W4/0
114	Rio Alto	00/07-06-080-06W4/0
115	Petro-Canada	00/10-14-080-08W4/0
116	AEC	00/06-06-080-09W4/0
117	AEC	00/08-20-080-09W4/0

Previously Approved Wells

	Licensee	Unique Well ID
1	BP Canada	00/10-07-077-08W4/0
2	Paramount	00/03-14-078-08W4/0
3	Paramount	00/05-15-078-08W4/0
4	Paramount	00/10-21-078-08W4/0
5	Paramount	00/06-28-078-08W4/0
6	Paramount	00/08-29-078-08W4/0
7	BP Canada	00/01-11-078-09W4/0
8	Paramount	00/08-15-078-10W4/0
9	Paramount	00/06-21-078-10W4/0
10	Paramount	00/08-32-078-10W4/0
11	Rio Alto	00/13-16-079-07W4/0
12	Rio Alto	00/12-17-079-07W4/0
13	Rio Alto	00/05-20-079-07W4/0
14	Rio Alto	00/13-13-079-08W4/0
15	Encana	00/12-19-079-08W4/0
16	Encana	00/10-26-079-09W4/0
17	Paramount	00/12-03-079-10W4/0
18	Paramount	00/11-04-079-10W4/0
19	Paramount	00/09-05-079-10W4/0
20	Paramount	00/12-09-079-10W4/0
21	Encana	00/11-07-080-09W4/0
22	Encana	00/12-17-080-09W4/0

APPENDIX 4. PETRO-CANADA CHARD AREA APPLICATION WELLS

Group	Unique Well ID	Wabiskaw-McMurray Interval (mKB)	Requested Disposition	Board-Interpreted Zone	Potential for Pressure Communication[1] Risk	Category
Group 1	00/11-20-079-06W4/0	274.9-279.2	Shut in	McM A	Low	6
	00/07-32-079-06W4/0	286.0-290.5	Shut in	McM A	Low	6
		291.0-292.5	Shut in			
	00/12-35-079-07W4/0	319.0-321.5	Shut in	McM B1	High	9
		348.5-350.0	Shut in	McM ch	High	11
	00/12-36-079-07W4/0	290.0-292.0	Shut in	McM A	Low	6
		302.5-304.0	Shut in	McM B1	High	9
	00/07-04-080-06W4/0	293.0-299.0	Shut in	McM A	Low	6
		304.0-305.0	Shut in	McM B1	Low	7
	00/06-20-080-06W4/0	285.5-288.0	Shut in	McM ch	High	11
	00/06-22-080-06W4/0	309.5-313.5	Shut in	McM A	Low	6
	00/07-23-080-06W4/0	250.5-253.5	Shut in	McM A	Low	6
	00/10-27-080-06W4/0	245.7-250.2	Shut in	McM ch	High	11
		251.8-252.4	Shut in			
	00/11-28-080-06W4/2	280.0-281.0	Shut in	Wbsk C	Low	2
		284.0-296.0	Shut in	McM ch	High	11
	00/10-11-080-07W4/0	315.1-319.0	Shut in	McM A	Low	6
	00/07-13-080-07W4/0	309.5-312.5	Shut in	McM ch	High	11
		313.5-314.5	Shut in			
		315.0-316.5	Shut in			
	00/07-14-080-07W4/0	319.5-321.0	Shut in	McM A	Low	6
		327.5-328.5	Shut in	McM B1	High	8
	00/03-34-080-07W4/0	331.0-332.0	Shut in	Wbsk C	Low	1
		334.5-337.0	Shut in	McM A	Low	6
		340.5-341.0	Shut in	McM B1	Low	7
		344.5-346.5	Shut in			
	00/04-35-080-07W4/0	315.0-316.0	Shut in	Wbsk C	Low	1
		319.5-322.0	Shut in	McM A	Low	6
		325.0-327.0	Shut in	McM B1	Low	7
		328.0-329.0	Shut in			
		331.5-333.0	Shut in	McM B2	Low	10
	02/10-14-080-08W4/0	375.5-378.0	Shut in	McM B1	Low	7
		379.5-380.5	Shut in			
	00/01-15-080-08W4/0	382.0-383.0	Shut in	McM B1	Low	7
	00/03-24-080-08W4/0	362.3-365.3	Shut in	McM B1	Low	7
	00/14-03-081-07W4/0	347.0-350.0	Shut in	McM A	Low	6
		352.5-354.5	Shut in	McM B1	Low	7
		356.0-358.0	Shut in			
	00/08-07-081-07W4/0	377.5-378.5	Shut in	Wbsk C	Low	1
		381.0-382.5	Shut in	McM A	Low	6
		386.0-388.0	Shut in	McM ch	High	11
	00/06-17-081-07W4/0	378.5-381.0	Shut in	McM A	Low	6
		385.0-386.0	Shut in	McM ch	High	11
	00/14-01-081-08W4/0	399.0-400.3	Shut in	McM A	Low	6
	00/11-13-081-08W4/0	440.0-441.0	Shut in	McM A	Low	6
		445.5-446.5	Shut in	McM B1	High	8
		457.5-458.5	Shut in	McM ch	High	11

(continued)

Group	Unique Well ID	Wabiskaw-McMurray Interval (mKB)	Requested Disposition	Board-Interpreted Zone	Potential for Pressure Communication[1]	
					Risk	Category
	00/10-14-081-08W4/0	451.0-451.5	Shut in	Wbsk C	Low	1
		453.0-454.0	Shut in	McM A	Low	6
		459.0-460.5	Shut in	McM B1	High	8
Group 2	00/16-34-078-07W4/0	281.0-282.0	Produce	Wbsk C	Low	1
		283.0-284.5	Produce	McM A	Low	6
	00/11-06-079-06W4/0	292.0-295.0	Produce	McM A	Low	6
	00/13-01-079-07W4/0	289.0-290.0	Produce	McM A	Low	6
		291.0-292.0	Produce			
	00/11-03-079-07W4/0	286.5-287.5	Produce	Wbsk C	Low	1
		288.5-290.0	Produce	McM A	Low	6
	00/10-10-079-07W4/0	291.0-293.0	Produce	Wbsk C	Low	1
	00/10-11-079-07W4/0	282.0-283.5	Produce	Wbsk C	Low	1
		284.5-288.5	Produce	McM A	Low	6
	00/10-12-079-07W4/0	283.0-285.0	Produce	McM A	Low	6
		291.5-292.5	Shut in	McM B1	High	8
		295.5-297.0	Shut in			
	00/10-36-079-08W4/0	333.5-334.7	Produce	Wbsk C	Low	1
		336.0-337.3	Produce	McM A	Low	6
		344.0-345.0	Shut in	McM B1	Low	7
		346.8-348.8	Shut in			
	00/11-06-080-07W4/0	351.5-352.5	Shut in	McM B1	Low	7
		355.0-356.0	Shut in	McM B2	Low	10
	00/10-23-080-07W4/0	315.5-319.0	Produce	McM A	Low	6
	00/08-30-080-07W4/0	355.5-357.0	Produce	Wbsk C	Low	1
		359.0-359.5	Produce	McM A	Low	6
		365.5-367.0	Shut in	McM B1	Low	7
	00/16-31-080-07W4/0	363.0-364.0	Produce	McM A	Low	6
		369.0-369.5	Shut in	McM B1	Low	7
	00/03-11-080-08W4/0	353.0-354.0	Produce	Wbsk C	Low	1
		355.0-356.0	Produce	McM A	Low	6
		356.0-357.0	Produce			
		363.0-365.0	Shut in	McM B1	Low	7
		366.0-368.0	Shut in			
	00/11-13-080-08W4/0	357.5-358.5	Produce	McM A	Low	6
		365.0-366.0	Shut in	McM B1	Low	7
		367.0-367.5	Shut in			
		369.0-370.0	Shut in			
	00/12-26-080-08W4/0	395.5-397.5	Produce	McM A	Low	6
		402.0-403.0	Shut in	McM B1	Low	7
	00/12-27-080-08W4/0	392.0-393.0	Produce	McM A	Low	6
		399.0-400.0	Shut in	McM B1	Low	7
		400.5-401.5	Shut in			
Group 3	00/11-08-079-06W4/0	244.0-248.0	Shut in if Necessary	McM A	Low	6
	00/10-16-079-06W4/0	230.5-233.0	Shut in if Necessary	McM A	Low	6
		234.0-237.0	Shut in if Necessary			

(continued)

Group	Unique Well ID	Wabiskaw-McMurray Interval (mKB)	Requested Disposition	Board-Interpreted Zone	Potential for Pressure Communication[1]	
					Risk	Category
	00/10-21-079-06W4/0	217.0-223.5	Shut in if Necessary	McM A	Low	6
	00/11-22-079-06W4/0	221.6-223.7	Shut in if Necessary	McM A	Low	6
		226.5-227.7	Shut in if Necessary	McM B1	Low	12
	00/11-28-079-06W4/0	250.5-257.0	Shut in if Necessary	McM A	Low	6
		260.0-261.0	Shut in if Necessary	McM B1	Low	12
	00/06-34-079-06W4/0	Perforations Abandoned	Shut in if Necessary			
	02/06-34-079-06W4/2	235.5-237.3	Shut in if Necessary	Wbsk C	Low	2
		246.0-247.5	Shut in if Necessary	Wbsk D	Low	12
	00/13-34-079-06W4/0	242.0-247.5	Shut in if Necessary	Wbsk C+D	Low	12
	00/13-35-079-06W4/0	236.0-241.0	Shut in if Necessary	McM A	Low	6
	00/16-22-079-08W4/2	346.5-347.5	Shut in if Necessary	Wbsk C	Low	1
		348.5-349.5	Shut in if Necessary	McM A	Low	6
		357.0-358.5	Shut in if Necessary	McM B1	Low	7
	00/12-23-079-08W4/2	332.0-333.5	Shut in if Necessary	Wbsk C	Low	1
		335.0-336.0	Shut in if Necessary	McM A	Low	6
	00/11-24-079-08W4/2	309.8-311.0	Shut in if Necessary	Wbsk C	Low	1
		321.0-322.0	Shut in if Necessary	McM B1	High	8
		324.0-325.0	Shut in if Necessary			
	00/01-26-079-08W4/0	338.0-339.0	Shut in if Necessary	Wbsk C	Low	1
		340.5-341.5	Shut in if Necessary	McM A	Low	6
		348.5-349.5	Shut in if Necessary	McM B1	High	9
	00/03-02-080-06W4/0	237.0-241.0	Shut in if Necessary	McM A	Low	6
	00/10-02-080-06W4/0	236.0-238.0	Shut in if Necessary	Wbsk D	Low	4
	00/03-03-080-06W4/0	249.5-253.0	Shut in if Necessary	McM A	Low	6
	00/09-11-080-06W4/0	222.0-223.0	Shut in if Necessary	Wbsk C	Low	1

(continued)

Group	Unique Well ID	Wabiskaw-McMurray Interval (mKB)	Requested Disposition	Board-Interpreted Zone	Potential for Pressure Communication[1]	
					Risk	Category
		224.5-229.0	Shut in if Necessary	McM A	Low	6
		232.0-233.0	Shut in if Necessary	McM B1	Low	12
	00/15-11-080-06W4/0	227.3-233.0	Shut in if Necessary	McM A	Low	6
		236.0-237.3	Shut in if Necessary	McM B1	Low	12
	00/05-12-080-06W4/0	208.5-209.5	Shut in if Necessary	Wbsk C	Low	1
		211.0-215.0	Shut in if Necessary	McM A	Low	6
		219.0-221.0	Shut in if Necessary	McM B1	Low	12
	00/04-13-080-06W4/0	213.5-214.5	Shut in if Necessary	Wbsk C	Low	1
		215.5-220.0	Shut in if Necessary	McM A	Low	6
		223.0-226.5	Shut in if Necessary	McM B1	Low	12
	00/07-14-080-06W4/0	240.0-245.0	Shut in if Necessary	McM A	Low	6
		247.5-249.0	Shut in if Necessary	McM B1	Low	12
	00/02-28-080-08W4/0	412.0-414.5	Shut in if Necessary	McM B1	Low	7
	00/15-34-080-08W4/0	429.0-430.0	Shut in if Necessary	McM B1	Low	7
	00/06-11-081-08W4/0	440.0-442.5	Shut in if Necessary	McM B1	Low	7
	00/11-22-081-08W4/0	444.5-447.3	Shut in if Necessary	McM ch	High	11
		450.0-451.0	Shut in if Necessary			
	00/12-23-081-08W4/0	445.0-448.0	Shut in if Necessary	McM ch	High	11
Group 4	00/13-27-078-07W4/0	283.0-284.3	Produce	Wbsk C	Low	1
	02/11-20-079-06W4/0	279.5-285.3	Shut in	McM A	Low	6
		321.3-321.6	Shut in	Shale	Low	13
	00/12-31-079-06W4/0	288.0-289.5	Shut in	Wbsk C	High	3
		300.0-301.5	Shut in	McM ch	High	11
		302.5-303.5	Shut in			
	00/11-02-079-07W4/0	No Perforations	Na			
	00/09-12-079-07W4/0	No Perforations	Na			
	00/11-13-079-07W4/0	269.0-270.6	Produce	Wbsk C	Low	1
		271.0-271.5	Produce	McM A	Low	6
	00/11-33-079-07W4/0	320.5-321.8	Produce	McM A	Low	6
	00/10-07-080-06W4/0	295.4-299.6	Shut in	McM A	Low	6

(continued)

Group	Unique Well ID	Wabiskaw-McMurray Interval (mKB)	Requested Disposition	Board-Interpreted Zone	Potential for Pressure Communication[1]	
					Risk	Category
		302.4-303.9	Shut in	McM B1	Low	7
		305.4-307.8	Shut in			
		309.4-315.2	Shut in	McM B2	Low	10
	00/11-09-080-06W4/0	305.5-311.0	Shut in	McM A	Low	6
		316.0-317.0	Shut in	McM B1	Low	7
	00/11-34-080-06W4/0	238.0-240.0	Shut in	Wbsk C	Low	1
		242.0-244.5	Shut in	McM A	Low	6
		250.0-251.0	Shut in	McM ch	High	11
	02/03-32-080-07W4/0	359.0-361.0	Produce	McM A	Low	6
		365.0-366.0	Shut in	McM B1	Low	7
		367.0-368.0	Shut in			
	00/16-03-080-08W4/0	384.5-385.5	Shut in	McM ch	High	11
	00/14-12-080-08W4/0	367.0-368.0	Shut in	McM B1	Low	7
		370.3-371.3	Shut in			
	00/05-23-080-08W4/0	379.5-380.5	Produce	McM A	Low	6
		386.0-387.0	Shut in	McM B1	Low	7
		389.0-391.0	Shut in			
	00/14-25-080-08W4/0	386.0-387.0	Shut in	McM A	Low	6
		393.0-394.0	Shut in	McM B1	Low	7
	00/11-25-081-08W4/0	443.0-444.5	Shut in	Wbsk D	High	4
	00/11-36-081-08W4/0	446.5-448.0	Shut in	Wbsk D	High	4
		456.0-457.0	Shut in	McM ch	High	11

[1] See Appendix 13 for category descriptions.

APPENDIX 5. LEISMER FIELD APPLICATION WELLS

Application No.	Unique Well ID	Wabiskaw-McMurray Interval (mKB)	Requested Disposition	Board-Interpreted Zone	Potential for Pressure Communication[1]	
					Risk	Category
1058461	03/10-14-076-07W4/0	338.0-340.0	Produce	Wbsk ch	High	5
1062688	00/10-12-079-10W4/0	393.0-394.0	Review	Wbsk D	High	4
		397.0-400.0	Produce	McM ch	High	11
1066525	00/12-32-076-06W4/0	305.5-307.5	Produce	Wbsk C	High	3
		308.5-309.0	Produce	Wbsk D	High	4
1066527	00/07-30-076-06W4/0	304.5-305.5	Produce	Wbsk C	High	3
1068637	02/07-34-076-07W4/0	307.5-308.5	Produce	Wbsk C	High	3
		309.5-311.5	Produce	Wbsk D	High	4
1071817	00/10-10-077-06W4/0	324.0-325.0	Produce	Wbsk D	High	4
		325.5-326.5	Produce	McM ch	High	11
1072845	00/05-28-075-07W4/0	414.5-417.5	Produce	Wbsk ch	High	5
	00/06-29-075-07W4/0	417.6-444.4	Produce	Wbsk ch	High	5
1072848	00/05-27-075-07W4/0	422.0-424.0	Produce	Wbsk ch	High	5
	00/01-34-075-07W4/0	389.0-390.0	Produce	Wbsk ch	High	5
1073875	00/10-22-077-06W4/0	315.0-316.0	Review	Wbsk D	High	4
		317.3-319.3	Review	McM ch	High	11
1078980	00/16-32-077-07W4/0	291.5-294.0	Produce	Wbsk C	High	3
	02/11-10-077-07W4/0	305.0-306.0	Produce	Wbsk C	High	3
		307.0-307.5	Produce	Wbsk D	High	4
1085736	00/05-15-077-06W4/0	308.5-310.0	Produce	McM ch	High	11
		312.9-316.5	Produce			
	00/12-11-077-07W4/0	304.5-308.3	Produce	Wbsk C + D	High	3 + 4
	00/06-13-077-07W4/0	302.5-305.2	Produce	Wbsk C + D	High	3 + 4
	00/08-15-077-07W4/0	308.5-312.4	Produce	Wbsk C + D	High	3 + 4
1086353	00/10-23-076-07W4/0	336.0-337.0	Shut in	Wbsk ch	High	5
	00/04-04-076-06W4/0	348.0-352.0	Shut in	Wbsk C + McM A	Low	1 + 6
		358.0-360.0	Shut in	McM B1	High	8
1088067	00/04-29-079-08W4/0	372.2-373.2	Produce	Wbsk C	Low	1
		374.5-375.5	Produce	McM A	Low	6
		382.8-385.0	Produce	McM B1	Low	7
	00/10-14-079-09W4/0	410.5-411.0	Produce	Wbsk C	Low	1
		412.5-413.5	Produce	McM A	Low	6
	00/09-21-079-09W4/0	411.5-413.0	Produce	Wbsk C	Low	1
	00/10-28-079-09W4/0	409.0-410.5	Produce	Wbsk C + McM A	Low	1 + 6
		412.0-412.5	Produce	McM A	Low	6
		417.0-418.5	Produce	Shale	Low	13
		420.0-421.0	Produce	McM B1	Low	7
		422.0-423.5	Produce			
	00/11-04-080-09W4/0	426.5-429.5	Produce	McM A	Low	6
		434.5-439.0	Produce	McM B1	Low	7
		440.5-441.5	Produce	McM B2	Low	10
	00/12-16-080-09W4/0	432.3-434.0	Produce	McM A	Low	6
		440.0-442.3	Produce	McM B1	Low	7
		444.0-445.5	Produce	McM B2	Low	10
1089982	00/12-12-078-10W4/0	370.3-371.0	Produce	Wbsk C	Low	1
		373.3-374.0	Produce	McM A	Low	6
		385.0-385.7	Produce	McM B2	Low	10

(continued)

Application No.	Unique Well ID	Wabiskaw-McMurray Interval (mKB)	Requested Disposition	Board-Interpreted Zone	Potential for Pressure Communication[1]	
					Risk	Category
1090128	00/01-04-079-07W4/0	286.8-287.8	Produce	Wbsk C	Low	1
	00/04-21-079-07W4/0	308.0-309.0	Produce	Wbsk C	Low	1
		310.5-312.0	Produce	McM A	Low	6
	00/12-22-079-07W4/0	311.5-312.5	Produce	Wbsk C	Low	1
	00/04-27-079-07W4/0	304.0-305.0	Produce	Wbsk C	Low	1
		306.5-307.5	Produce	McM A	Low	6
	00/04-10-079-08W4/0	319.5-320.5	Produce	Wbsk C	Low	1
	00/13-15-079-08W4/0	336.0-337.5	Produce	Wbsk C	Low	1
		339.0-340.5	Produce	McM A	Low	6
1090265	00/15-22-079-10W4/0	423.5-425.0	Produce	McM ch	High	11
		430.0-430.6	Produce			
1090454	00/05-34-078-07W4/0	282.0-283.0	Produce	Wbsk C	Low	1
		284.0-285.0	Produce	McM A	Low	6
	00/02-10-079-07W4/0	286.5-288.0	Produce	Wbsk C	Low	1
		289.0-291.0	Produce	McM A	Low	6
	00/04-13-079-07W4/0	283.0-284.0	Produce	Wbsk C	Low	1
		285.0-287.0	Produce	McM A	Low	6
	00/01-15-079-07W4/0	292.5-293.5	Produce	Wbsk C	Low	1
		295.0-297.0	Produce	McM A	Low	6
1091676	00/10-01-079-08W4/0	295.0-296.0	Produce	Wbsk C	Low	1
		298.0-299.0	Produce	McM A	Low	6
		305.3-306.3	Produce	McM B1	Low	7
		309.0-310.0	Produce			
	00/10-02-079-08W4/0	299.6-300.3	Produce	Wbsk C	Low	1
		302.5-303.5	Produce	McM A	Low	6
1091687	00/06-18-079-09W4/0	401.0-403.0	Produce	Wbsk D	High	4
1092171	02/15-23-077-09W4/0	333.8-335.2	Produce	Wbsk C	Low	1
		336.9-339.0	Produce	McM A	Low	6
1093063	00/06-02-077-08W4/0	337.0-338.5	Produce	Wbsk C	Low	1
		339.5-341.0	Produce	McM A	Low	6
	00/09-34-077-08W4/0	300.5-301.5	Produce	Wbsk C	High	3
1096254	00/12-20-077-06W4/0	306.5-309.0	Produce	Wbsk C + D	High	3 + 4
1097088	00/06-30-077-07W4/0	290.5-294.0	Produce	Wbsk C + D	High	3 + 4
1097089[2]	00/12-29-076-07W4/0	314.0-316.5	None	McM ch	High	11

[1] See Appendix 13 for category descriptions.
[2] Devon withdrew this application to produce gas at the hearing.

APPENDIX 6. PANCANADIAN APPLICATION WELLS[1]

Application No.	Unique Well ID	Wabiskaw-McMurray Interval (mKB)	Requested Disposition	Board-Interpreted Zone	Potential for Pressure Communication[2] Risk	Category
1256085	00/06-36-075-06W4/2	356.0-359.0	None	Wbsk D	High	4
		362.0-363.0	None	Wbsk D	High	4
		365.0-366.0	None			
		373.0-376.0	None	McM ch	High	11
	00/07-30-076-05W4/0	315.0-316.0	None	Wbsk C	High	3
		318.0-320.0	None	Wbsk D	High	4
	00/04-01-076-06W4/0	358.0-360.0	None	Wbsk C + D	High	3 + 4
		366.0-367.0	None	Wbsk D	High	4
		368.0-369.5	None			
	00/04-03-076-06W4/0	351.5-352.5	None	Wbsk D	High	4
	00/06-11-076-06W4/0	338.5-339.5	None	McM ch	High	11
		340.5-347.5	None			
	00/06-12-076-06W4/0	345.0-352.0	None	McM ch	High	11
	00/08-13-076-06W4/0	341.5-347.0	None	McM ch	High	11
	00/06-14-076-06W4/0	317.5-318.5	None	Wbsk C	High	3
		321.0-323.0	None	Wbsk D	High	4
	00/06-15-076-06W4/0	322.0-324.5	None	Wbsk D	High	4
		330.5-331.0	None	McM ch	High	11
		342.0-346.0	None	McM ch	High	11
	00/11-16-076-06W4/0	318.5-321.5	None	Wbsk C + D	High	3 + 4
	00/06-24-076-06W4/0	320.5-326.0	None	Wbsk C + D	High	3 + 4
		330.7-332.0	None	McM ch	High	11
		338.5-343.0	None	McM ch	High	11
	00/08-25-076-06W4/0	324.0-326.0	None	McM ch	High	11
	00/07-28-076-06W4/2	301.1-302.1	None	Wbsk C	High	3
		303.0-304.8	None	McM ch	High	11
	00/06-03-077-06W4/0	309.0-309.5	None	Wbsk D	High	4
	00/10-05-077-06W4/2	366.4-368.2	None	Bsl McM ch	Low	13
		371.9-373.7	None			
	00/05-08-077-06W4/0	301.3-303.0	None	Wbsk C	High	3
		303.4-305.3	None	McM ch	High	11

[1] PanCanadian's application to shut in these wells was withdrawn prior to the conclusion of the hearing.
[2] See Appendix 13 for category descriptions.

Appendix 7 EUB Letter Regarding Preliminary Meeting

Calgary Office 640 – 5 Avenue SW Calgary, Alberta Canada T2P 3G4 Tel 403 297-8311 Fax 403 297-7336

April 26, 2001

TO: INTERESTED PARTIES (SEE ATTACHED LIST)

Dear Sir or Madam:

RE: MARCH 27, 2001 MEETING
LEISMER FIELD AND CHARD AREA

The Alberta Energy and Utilities Board (EUB/Board) has considered the diverse positions put forward by parties at the March 27, 2001 meeting regarding thirteen applications involving production of gas from the Wabiskaw-McMurray in the Leismer Field and Chard area. The Board has instructed me to advise you of its decisions pertaining to the following issues discussed at the meeting:

- the process and schedule for reviewing the applications;
- the need for a process to review grandfathered gas production[1] in the Leismer Field;
- the issues that need to be considered at a hearing;
- interim shut in of gas production; and
- the role of the EUB Staff Group.

With respect to the process and review of the applications, the Board is of the view that to properly and effectively consider and weigh all the relevant issues related to the applications, a common proceeding should be convened. The Board does not accept that an application-by-application or well-by-well approach is an appropriate means to address the issue of bitumen conservation in the Leismer Field, considering the potential for a really extensive overlying gas and water zones. Accordingly, the Board has decided that the proceeding should also include a review of all Wabiskaw-McMurray gas production in the Leismer Field[2] including grandfathered gas production.

The Board considers the EUB Staff Group to be the complainant in connection with the review of grandfathered gas production in the Leismer Field (including Proceeding No. 1073875), as contemplated by Section 3(5) of the *Oil Sands Conservation Regulation*, and an intervener in the other applications presently before the Board. The Board's decision to review grandfathered gas production in the Leismer Field may have the consequence of drawing additional gas and bitumen operators/lessees into the proceeding to speak to their interests. The proceeding schedule outlined below takes into account that such parties may wish to participate and is also predicated on the above-described thirteen applications being in a completed state by July 3, 2001, including any additional information required by the Board.

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[1] Grandfathered gas production refers to production from wells completed in the defined oil sands strata prior to July 1, 1998.
[2] This includes Wabiskaw-McMurray gas production from wells that are within an EUB G Order that overlaps the Leismer Field.

The Board notes that, recently, additional applications to produce gas in the Leismer Field and Chard area have been received from companies and anticipates that more may be filed in the near future. The Board will include all such applications in the proceeding provided that they are submitted in a complete form by July 3, 2001, and are in the area shown on the attached map [not included in this appendix of *Decision 2003-023*]. After that time, the processing of all applications received by the Board to produce gas in this area will be held in abeyance pending the issuance of the Board's decision regarding the proceeding.

The following proceeding schedule is designed to provide all parties with a reasonable opportunity to prepare and file thorough submissions, interrogatories, and responses no later than the date indicated:

1.	Filing of EUB Staff Group submission, Franco-Nevada Section 42 application, and any additional applications to produce gas	July 3, 2001
2.	Information requests issued by Interveners to Applicants and EUB Staff Group	July 24, 2001
3.	Applicants and EUB Staff Group respond to information requests	August 14, 2001
4.	Filing of Intervener submissions	September 4, 2001
5.	Information requests issued by Applicants and EUB Staff Group to Interveners	September 25, 2001
6.	Interveners respond to information requests	October 16, 2001
7.	Applicants and EUB Staff Group rebuttal	October 30, 2001
8.	Hearing commencement	November 13, 2001

The Board will issue a notice of hearing respecting the above schedule in due course.

The Board has determined that the hearing will be segmented into three parts.

i. In part one, the Petro-Canada Oil and Gas application to shut in gas in the Chard area will be heard in its entirety followed by all interventions and rebuttal evidence relating to the application.

ii. In part two, the EUB Staff Group will present its submission regarding grandfathered gas production in the Leismer Field. This will be followed by the evidence of applicants in support of their applications to produce gas in the Leismer Field and Chard area. The Board recognizes that parties with specific applications to produce gas will also have an interest in the grandfathered gas production issue, and, therefore, applicants will also present their evidence on grandfathered gas production at this time. The Board will then hear from interveners concerned with the grandfathered gas production issue as well as interveners interested in specific applications to produce gas. Again, the Board appreciates that there will be interveners who have an interest in both matters. Rebuttal by applicants and the Board Staff Group would conclude the evidentiary portion of the hearing. To address timing and efficiency concerns, the Board will allow Franco-Nevada Mining Corporation Limited to provide evidence in support of its Application No.

1086353 at the time allocated for interveners. However, it will still have the onus associated with an applicant pursuing a Section 42 review under the Energy Resources Conservation Act.

iii. In part three, the Board will hear closing arguments from all the hearing participants.

On the basis of the input received from the meeting participants, the Board identified the following general issues as matters for consideration at the hearing:

- the extent of the affected resources/reserves;
- the relative value of the gas reserves and bitumen resources;
- geological interpretation; and
- the impact of gas production on bitumen recovery.

The Board recognizes that there may be other issues that parties want to address at the hearing, and, therefore, it is not the intent of the Board necessarily to limit the scope of the hearing to the above issues only.

With respect to the matter of shutting in gas production pending the outcome of the hearing, the Board believes that the evidence required to make such a determination is both detailed and complex. Accordingly, the Board is not prepared to make such a decision in advance of considering all the evidence at the hearing scheduled to commence on November 13, 2001.

With respect to the role of the EUB Staff Group, the Board continues to view its participation as appropriate in the circumstances of the present proceeding and within the authority of the Board to accept. The Board notes in the submission of the EUB Staff Group to the March 27, 2001 meeting that it has effectively separated itself from other Board staff on matters pertaining to this proceeding. The EUB Staff Group will not be treated differently than other participants. It will be required to respond to information requests, be entitled to issue information requests, and be subject to cross-examination at the hearing.

Yours truly,

Douglas A. Larder
Board Counsel

Attachment

Appendix 8 EUB Letter Regarding Applications for Review of Decision to Convene a Common Hearing

File No. 7000-1085793-01

June 4, 2001

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Robert Perrin
McCarthy Tetrault
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Calgary, AB T2P
Fax: 260-3501

TO ALL OTHER INTERESTED PARTIES

Dear Sir:

RE: Section 42/43 Energy Resources Conservation Act Requests regarding Board Decision of April 26, 2001 by:

AEC Oil and Gas (AEC)
BP Canada Energy Company (BP)
Paramount Resources Ltd. (Paramount)
Anderson Exploration Ltd. (Anderson)
Petro-Canada Oil and Gas (Petro-Canada)

Background

The Board issued a letter dated April 26, 2001 directing that a combined hearing be conducted to consider:

- several gas production applications in the Leismer area by various gas producers;
- a shut-in application of approximately 40 gas wells in the Chard area by Petro-Canada; and
- a review of existing grandfathered gas production in the Leismer area with a view to shutting-in existing gas wells, by the Board Staff Submission group.

The Board outlined the process to be followed at the hearing and confirmed that the Board Staff Submission group would be allowed to participate.

As a result of the Board's decision, the above described parties have filed section 42 and/or 43 review requests dated May 23 (Anderson), May 24 (BP), and May 25 (BP and Paramount). Petro-Canada's request is somewhat narrower than the others and relates to the timing of argument on the Chard area portion of the main proceeding. It is outlined in its letter of May 8, 2001. The Board invited other interested parties to respond to the review applications and received one dated June 14 from counsel for the Staff Submission Group indicating that it had no comment and one from Petro-Canada dated June 14 confirming that it wished to preserve the present timing and structure of its Chard area hearing.

The issues raised in support of a review and the Board's comments follow:

Combined Hearing

Anderson, BP, Parmount and AEC make the argument that a combined hearing is an error of law because it compels several parties with several applications, including the Staff Submission Group's review of grandfathered production, to present a wide and differing set of issues, facts and argument concurrently. The result, they maintain, is that the Board will be unable to focus on specific circumstances of each well and be more likely to apply inappropriate findings from one part of the hearing to other parts. They argue that the danger exists that the Board will misdirect itself because of the number of parties and volume and complexity of the issues.

The Board believes that it does have the capacity to consider a great volume of highly complex and technical evidence from a number of parties and make the necessary findings of fact and other determinations necessary for a fair and reasoned decision for each application. There is no indication that the Board has been unable to perform this basic discernment in the past regarding gas/bitumen issues i.e. Gulf Surmont decision, nor that it has failed to properly carry out this function in any other challenging, complex, multi-party hearing. The weighing of specific evidence, the findings of relevance and the application of judicially reached findings to the matter at hand are fundamental responsibilities of the Board at a hearing.

Insufficient Evidence of Areally Extensive Overlying Gas and Water Zones

Paramount, Anderson and AEC submit that the Board made its decision to hold a combined hearing on the basis of the Staff Submission Group's technical conclusions presented to the meeting on March 27, 2001, regarding regions of influence, in the absence of an opportunity for other parties to counter or respond to the Staff Group's position or for the evidence upon which the conclusions were founded being reviewed in any way by the Board. It should be noted that Franco-Nevada, Koch and Wascana took the same view as the Staff Submission Group regarding the potential for regions of influence. Parties were not prevented from advancing any geological conclusions at the meeting. The Board did not want to hear evidence but for the purposes of scoping out and supporting the parties' positions on the various issues, technical conclusions could have been presented.

Further, the Board is an expert tribunal in matters relating to the conservation of oil and gas. It need not nor cannot ignore the expertise and knowledge built up through its members and staff assisting the Board on this matter ("staff" does not refer to the Staff Submission Group in this context) regarding general and specific gas/bitumen issues in northern Alberta when considering the most efficient and appropriate method of conducting a hearing for one or many applications. The issue of areally extensive water and gas zones overlying bitumen is a basic one for these types of applications. The Board's decision to hold a combined hearing because of the potential for such a geological backdrop is an expression of the Board's best judgment on the most efficient and reasonable course of action to consider the many applications before it.

Participation of Staff Submission Group

BP, AEC and Paramount argue that the Panel's approval of the Staff Submission Group's participation at the hearing results in a reasonable apprehension of bias because of the perception that the Board has directed the Staff Group's intervention or has implicitly concurred with its submission because it is employed by the Board. Paramount adds that the individual members on the Staff Group may also bring a bias to the issues if they have worked on the Gulf Surmont application/hearing.

The Board's Rules of Practice allow for a staff submission and participation of staff where "…in the opinion of the Board or staff it is proper for the applicant to be made aware of the views of the Board staff…" (Section 27). The Oil Sands Conservation Regulations also acknowledge that the Board, on its own initiative may take action to shut-in grandfathered production (Section 3(5)). This may be accomplished by Board staff initiating a complaint and participating in a hearing. It is the Board's view that such involvement does not raise a tenable perception of bias if the Staff Submission Group is segregated from the Panel, and staff assisting the panel, with respect to the substantive matters before the Panel. The Board has so directed the Staff Submission Group. Communication regarding administrative and procedural matters has been and will continue to be conducted by counsel for the Staff Submission Group.

With respect to the participation of members of the Staff Submission Group in the Gulf Surmont proceedings, the Board observes that person's views and positions are formed from a variety of sources and experiences and education. To the extent that Staff Submission Group members have reached certain views, in part or wholly from their time at the Gulf Surmont hearing, is not a sufficient reason to prevent them from participating as part of the Staff Submission group. It is the Panel, not the Staff Submission Group, which has the responsibility for decision-making and the Panel's decision on the issues will depend on the particular facts and circumstances adduced by all parties at the combined hearing.

Sufficient Time to Prepare for Hearing

BP argues that it will have insufficient time and opportunity to properly respond to the case against it given the complexity of the issues and schedule of filings by the parties directed by the Board. The Board is not persuaded that the time scheduled to prepare BP's case regarding its own applications and its response to the grandfathered production review is manifestly unfair. The Board acknowledges that time frames required for the various filings are tight, but believes they are sufficient and provide parties with a fair opportunity to advance their positions.

Error of Fact

Anderson and Paramount argue that the Board made an error of fact by describing the views of the parties as "diverse" in reference to the mode of hearing. They state that there was not a multiplicity of views, only for and against, on the type of the hearing to be held. If the Board was basing its decision to hold a common hearing because it perceived there to be a variety of views on the topic, it was wrong they submit.

The Board stated that it had "…considered the diverse positions put forward by parties at the March 27, 2001 meeting regarding thirteen applications involving production of gas from the Wabiskaw-McMurray in the Leismer Field and Chard area." The adjective in question did not solely refer the parties' views on the type of hearing to be held but rather on all the issues connected to the applications. In any event, the word's meaning is broad enough to describe the various parties' views on the type of hearing to be held.

Order of Presentation

AEC submitted that the order of presentation of the various applications and the designation of the Staff Submission Group as a complainant in the grandfathered gas production review created an unfairness. It did not elaborate on this ground for review. It is the Board's view that the relevant consideration is that all parties be given a fair opportunity to present their applications and respond to those adverse in interest and that the current order of presentations meets this principle.

Pre-Assessment of AEC's Applications

AEC further seeks to have the Board review its decision to include its applications as part of the combined hearing. It asks the Board to examine the merits of its individual applications and conclude that gas production from its wells does not negatively impact the bitumen resource. The Board, however, has decided to consider these applications as part of a combined hearing. There will be no pre-hearing assessment of the merits of any of the applications going to the combined hearing in November. Until all the evidence is heard on the AEC wells and tested through cross-examination and argument, such a determination would be premature and defeat the purpose of a combined hearing.

With respect to the approval of the one gas zone for the AEC well referenced in its submission (Application # 1062688), it should be noted that the approval was based on an interpretation using criteria that had not been tested by way of a hearing. Additional views and examination of the issue will be available to the Board at the hearing. The Board is not bound by its earlier decision in light of changing circumstances and believes that there is benefit in including this well in the combined hearing.

Chard Argument at Conclusion of Part 1 of Combined Hearing

Petro-Canada asked the Board to reconsider its decision to hear all argument, including Chard, at the conclusion of the combined hearing. It wants argument on Chard to be given immediately after the Chard evidence so matters will be fresher in the minds of the parties and the Board and so the Board will be less likely to be distracted by the evidence heard in the Leismer part of the hearing.

These are not sufficient reasons to trigger a review. Parties and the Board have access to transcripts of the proceedings and notes taken during the hearing, for reference and consideration. If there are common findings in the two areas, then all parties will have the opportunity at the same time to present argument.

Conclusion on section 42 Review Request

The reasons advanced by the various parties for review under section 43 ERC Act do not establish a substantial doubt as to the correctness of the Board's decision of April 26, 2001 so as to trigger a review on the merits. Accordingly, the applications for review are denied.

Section 43 Energy Resources Conservation Act

Anderson has referred to section 43 as an avenue of review and reconsideration but it does not flesh out its argument in this regard. If the Board makes a decision which affects the rights of a person, without holding a hearing, that person has recourse to a hearing to consider his/her position. However, a decision to hold a combined hearing is a procedural one, not a substantive decision on the merits of an application. Anderson is entitled to have the Board consider its application to produce gas. It does not have the right to automatically obtain permission to produce gas or to have its application heard at a certain time or in a certain manner. The Board has the discretion, subject to the rules of procedural fairness and its enabling legislation, to conduct its statutory responsibilities, including the process it will follow to consider applications to produce gas, as it deems appropriate. It is the Board's view that no rights are being negatively affected so as to engage section 43 of the ERC Act.

Yours truly,

Douglas A. Larder
Counsel

Appendix 9 EUB Decision Report Regarding Petro-Canada Interim Shut-in Request

ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

PETRO-CANADA OIL AND GAS
INTERIM SHUT-IN OF GAS PRODUCTION **Decision 2001-63**
CHARD AREA **Application No. 1094706**

1 INTERIM DECISION

Having considered the evidence submitted to the interim hearing, the Alberta Energy and Utilities Board (EUB/Board) concludes that continued production of associated gas from certain zones in 10 wells may present a significant risk to future bitumen recovery and may result in associated economic losses in portions of the Chard area, pending the outcome of the main hearing of applications scheduled to commence on November 13, 2001. Accordingly, the Board grants the subject application in part. Specifically, the Board will order the interim shut-in of associated gas production effective September 1, 2001, from specific perforated intervals within the McMurray Formation in 10 wells listed in Appendix 1. The wells are to remain shut in pending the Board's final decision regarding Application No. 1085793. An order requiring the interim shut-in of gas production will be issued shortly.

This interim decision should not be considered as conclusive or permanent with regard to the issues to be addressed at the main hearing. An interim decision necessarily means that the Board did not have the benefit of the entirety of the evidence and argument that will ultimately be made available to it, nor was it in a position to assess the merits based on the totality of evidence. Accordingly, the Board will not be bound by the above interim decision.

2 INTRODUCTION

2.1 Background

On January 29, 2001, Petro-Canada Oil and Gas (Petro-Canada) applied, pursuant to Section 3(5) of the Oil Sands Conservation Regulation (OSCR), for an order to shut in Wabiskaw-McMurray gas production from specific wells located in and surrounding the area of its Chard oil sands leases (i.e., Application No. 1085793). Petro-Canada submitted that the order was needed to prevent the continuing adverse impact on the ultimate recovery of underlying bitumen due to pressure depletion as a result of gas production. Petro-Canada's Chard oil sands leases are located in whole or in part in Townships 79 to 81, Ranges 6 to 8, West of the 4th Meridian.

On April 26, 2001, the Board issued its decision to proceed with a common hearing on both specific gas production applications and the review of existing gas production in the Leismer Field and Chard area, including Petro-Canada's application to shut in gas production at Chard. Furthermore, with respect to the matter of shutting in gas production pending the outcome of the main hearing, the Board decided that the evidence required to make such a determination is both detailed and complex and, therefore, was not prepared to make such a decision in advance of considering all the evidence at the main hearing.

2.2 Application and Interventions

On May 25, 2001, Petro-Canada applied, pursuant to Sections 42 and 43 of the Energy Resources Conservation Act (ERCA), for the interim shut-in of Wabiskaw-McMurray gas production from 40 wells in the Chard area, pending the Board's final decision from the main hearing. Petro-Canada submitted that the Board erred in its April 26, 2001, decision to not shut in gas production pending the outcome of the main hearing, because the energy statutes require the Board to fulfill its conservation mandate on an interim as well as on a permanent basis. Petro-Canada further submitted that the Board's decision was subject to a review under Section 43 of the ERCA, since the Board did not hold a hearing prior to making its decision.

The Board subsequently received a submission from the Chard Gas Producers (CGP), consisting of Calpine Canada Natural Gas Company, Canadian Forest Oil Ltd., Paramount Resources Ltd., and Rio Alto Exploration Ltd., dated June 4, 2001, and a submission from Northstar Energy Corporation (Northstar), dated June 4, 2001. Both the CGP and Northstar opposed Petro-Canada's request for a review or hearing of its application for the interim shut-in of gas production at Chard, submitting that the matter could only be properly considered at the main hearing. The CGP further submitted that the Board does not have the jurisdiction to grant an interim shut-in order of the nature sought by Petro-Canada. It argued that the Board's decision to not shut in gas pending the outcome of the main hearing was an interlocutory decision and that, therefore, Section 43 of the ERCA could not be used in this context.

On June 5, 2001, the Board issued its decision (Appendix 2) to conduct a hearing to consider Petro-Canada's application for the interim shut-in of gas production from 40 wells in the Chard area.

2.3 Hearing

A public hearing of the subject application was held from July 3 to 5, 2001, in Calgary, Alberta, before J. D. Dilay, P.Eng., B. T. McManus, Q.C., and C. A. Langlo, P.Geol. A list of those who appeared at the hearing is provided in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Petro-Canada Oil and Gas (Petro-Canada)	
W. T. Corbett, Q.C.	J. Fong, P.Eng.
S. R. Miller	C. Hartford, P.Eng.
	D. Lee, P.Geol.
AEC Oil & Gas (AEC)	
R. M. Perrin	
Chard Gas Producers (CGP)	D. Bertram, P.Eng., of Adams Pearson Associates Inc.
K. F. Miller	L. Mattar, P.Eng., of Fekete Associates Inc.
	P. Putnam, Ph.D., P.Geol., of Petrel Robertson Consulting Ltd.
	C. Riddell, P.Geol., of Paramount Resources Ltd.
Northstar Energy Corporation (Northstar)	
S. M. Munro	G. Birrell
	J. Pearce, P.Eng,
	A. Stroich, P.Eng.
Alberta Energy and Utilities Board staff	
M. E. Connelly, P.Geol.	
G. W. Dilay, P.Eng.	
K. M. Johnston	
D. A. Larder	
K. F. Schuldhaus, P.Eng.	

3 JURISDICTION OF THE BOARD TO ISSUE AN INTERIM SHUT-IN ORDER

In the circumstances of the present application, the Board derives its authority to shut in existing gas production on an interim or interlocutory basis from Section 15 of the ERCA and Section 3(5) of the OSCR. The validity of the regulation was recently upheld by the Alberta Court of Appeal in the Giant Grosmont Decision,[1] which, in holding that the regulations were intra vires the Board, affirmed that the combined effect of the relevant energy legislation (i.e., ERCA, Oil and Gas Conservation Act, Oil Sands Conservation Act, Alberta Energy and Utilities Board Act)

[1] Giant Grosmont Petroleums Ltd. et al. vs. Gulf Canada Resources Ltd., Petro-Canada, and EUB, Unreported, June 29, 2001 (C.A.)

was to imbue the Board with the necessary authority, implied or explicit, to fulfill its primary statutory duty of ensuring that energy resources are not wasted.

It is the Board's view that the specific power to grant an interim shut-in order for conservation purposes is clearly set forth in Section 3(5) of the OSCR, which states:

> 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 its own initiative or on 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.

The words used in the regulation are broad and clear. The Board may make any order it deems necessary for the conservation of bitumen. The Board considers that the issuance of an interim shut-in order in appropriate circumstances falls within the authority granted to it by this provision. Section 15 of the ERCA further enhances the Board's authority by investing it with the power to do all things that are necessary for or incidental to the performance of the Board's statutory responsibilities.

The Board appreciates that there is a limited evidentiary record upon which to make an interim decision. There will be a great deal more evidence to be considered at the main hearing. It is important to note that the Board is not engaged in the final determination of the merits of the respective parties' positions and that this interim decision should not be interpreted in that light.

With respect to the appropriate test on an interim shut-in application, it is the Board's view that while the tripartite test utilized in civil litigation may offer some general guidance to the Board's deliberations, its strict application does not provide the appropriate basis upon which an interim shut-in application should be considered. The issue from the Board's perspective is one of conservation of energy resources in the public interest and, specifically, the impact of producing gas wells on the conservation of bitumen pending the outcome of the main hearing. The conservation issue will be moot at the main hearing if, for example, the ongoing pressure decline of the overlying gas zone leading up to the main hearing significantly reduces or sterilizes the ultimate recovery of the bitumen resource.

An interim shut-in application does not require irreparable harm to be established conclusively or that the Board conduct an analysis of the balance of convenience between the parties regarding the shut-in of gas. Where it appears to the Board that bitumen recovery may be affected by gas production, the Board may take such conservation action that it deems necessary. This is not to say that on an interim basis the nature of the potential competing harm to the parties is not a relevant consideration, only that the Board is not bound to apply the strict tripartite test in determining whether to grant an interim shut-in order. The Board's focus is centred on the potential for the significant waste of bitumen resources during the period required to consider the main shut-in application.

On the evidence before it, the Board believes that a serious issue has been raised by Petro-Canada regarding continuing pressure depletion of overlying gas zones through production of gas from certain wells.

The Board is of the view that it does not have the authority to compel Petro-Canada to provide an undertaking for damages, as would likely be the case in most civil actions where interim injunctive relief is granted. There is no provision in the energy statutes that allows the Board to make an order for this type of compensation. To the contrary, Section 91 of the Oil and Gas Conservation Act specifically reserves the power to the Lieutenant Governor in Council to direct compensation be paid to parties suffering damages resulting from Board orders.

4 ISSUES

The Board considers the issues with regard to the subject application to be as follows:

- geological interpretation,
- effect of associated gas production on bitumen recovery by steam-assisted gravity drainage (SAGD),
- feasibility of artificial repressuring,
- economics and public interest, and
- submission of pressure data.

5 VIEWS OF THE BOARD

Given the interim nature of the subject application and the need to issue a timely decision, this report contains only the views of the Board and not the views of the hearing participants, as is the Board's normal practice.

5.1 Geological Interpretation

The Board has reviewed the geophysical logs of wells in the Chard area, in particular the 40 gas wells that Petro-Canada is requesting be shut in. The Board believes that the bitumen-bearing, fining-upward, stacked channel sands of the McMurray Formation at Chard are analogous to Surmont. However, the Board recognizes that there may be other reservoir sands, in addition to stacked channel sands, especially in the upper part of the McMurray Formation. Based on well log character, the Board agrees that in the upper part of the McMurray Formation there are three coarsening-upward sand-dominated sequences, as identified by the CGP. The uppermost and the lowermost sequences appear to be correlatable over large areas of Chard. Both intervals are characterized by a basal mudstone, approximately 1 metre thick, that has a high gamma ray reading and resistivity reading of 7 to 9 ohm-metres. Where these basal mudstones are present, fluid distribution in some cases supports vertical separation. On the basis of the evidence before it, the Board believes that where these two basal mudstones have been preserved, the gas in the intervals above them is not in vertical communication with the underlying bitumen.

However, where later channels have downcut and removed these coarsening-upward sequences and associated mudstones, there is no evidence of vertical separation between gas and the underlying bitumen. The lowermost coarsening-upward sequence, although present over much of the Chard area, is the most commonly eroded. The uppermost coarsening-upward sequence is the best preserved and appears to correlate to the bayfill sheet sandstone described by Petro-Canada.

The middle parasequence interval, identified by the CGP, is a more complex unit in that the Board finds it does not have the same consistent coarsening-upward log character as seen in the other two intervals, nor is there a correlatable basal mudstone unit associated with it. Therefore, based on the lack of an associated mudstone unit, the Board does not recognize any vertical barriers separating this sand interval from the lowermost coarsening-upward sequence or, in its absence, any underlying stacked channel sandstones.

Bitumen occurring within these three upper McMurray sequences is thin and vertically separate from the thick bitumen sands of the underlying stacked channels and the Board does not expect it to be thermally exploitable. However, the Board believes that the bitumen within the underlying stacked channel sands at Chard is of sufficient quantity and quality to warrant consideration for protection for future development.

The Board has reviewed the relationship of the overlying Wabiskaw C sand to the McMurray sands. The Board believes that in instances where the three coarsening-upward sequences have been removed by channelling, the Wabiskaw C gas is vertically separated from McMurray gas and bitumen by a laterally correlatable intervening shale associated with the Wabiskaw C sand. On this basis, the Board does not believe that shut-in of Wabiskaw gas production is necessary at this time.

The Board is relying on the above interpretation of the upper McMurray and Wabiskaw C sands to assess Petro-Canada's application for the interim shut-in of 40 gas wells at Chard. The Board identified gas zones that have the potential to be in vertical communication with the underlying bitumen. The Board then reviewed the gas and water pools for the identified wells, as mapped by both Petro-Canada and the CGP, to determine any subsequent wells that have gas or water zones in lateral communication. For the purposes of this interim decision, the Board relied on the definition of a region of influence as stated in EUB *Interim Directive 99-1*.[2] Appendix 1 lists 10 wells and the specific perforated intervals, all within the McMurray Formation, for which the Board believes there is potential communication between the gas and the bitumen in the underlying stacked channel sands.

5.2 Effect of Associated Gas Production on Bitumen Recovery by SAGD

As was the case in the general inquiry[3] and the Gulf Surmont Hearing, assessment of the impact of gas production on bitumen recovery by SAGD for this interim shut-in application was based on reservoir simulation. Petro-Canada used the same simulation work it submitted to the Gulf Surmont Hearing (with the addition of a third reservoir model), which the Board notes was

[2] EUB *Interim Directive 99-1: Gas/Bitumen Production in Oil Sands Areas—Application, Notification, and Drilling Requirements*, February 3, 1999.

[3] *EUB Inquiry: Gas/Bitumen Production in Oil Sands Areas, March 1998.*

extensively debated at that hearing. With respect to the CGP's simulation work, the Board notes that it was an interim model study and that a three-dimensional (3-D) probabilistic geological model is currently being developed to corroborate the results of the interim model study. Although Northstar did not conduct its own simulation study, by referring to Petro-Canada's simulation work it stated that for the Chard A prospect, shutting in gas at this time would reduce the recovery of bitumen by 40 per cent compared to the recovery achievable if the overlying zone is repressured to 1750 kilopascals absolute (kPaa). This indicates to the Board that Northstar acknowledges that low gas zone pressures can have a significant negative impact on bitumen recovery.

Notwithstanding the Board's acknowledgement about the uncertainties with using reservoir simulation, it concluded that the reservoir modelling work submitted to the Gulf Surmont Hearing (which included Petro-Canada's modelling work) reasonably demonstrated that producing associated gas in the Surmont area would likely have a detrimental effect on SAGD performance and that the detrimental effect increases with decreasing gas cap pressure. Considering the previous extensive debate on Petro-Canada's simulation work and the differing views presented at the interim hearing, the Board believes there needs to be a more thorough debate of the simulation work for the Chard area before it is prepared to reconsider its conclusions on the simulation work submitted by Petro-Canada to the Gulf Surmont Hearing. Until this is done at the main hearing, the Board is of the view that producing gas from the specific perforated intervals in the 10 wells listed in Appendix 1 could have a detrimental effect on bitumen recovery.

For these 10 wells, the Board notes Petro-Canada's estimate that the pool pressures in January 2001 for 7 of the wells were in the range of 335 to 550 kPaa and for 2 of the wells were about 970 kPaa. No estimate was provided for one of the wells because of limited data. For the same 10 wells, the CGP estimated that the pool pressures in February 2001 for 4 of the wells were in the range of 350 to 570 kPaa and for 2 of the wells were in the range of 1000 to 1085 kPaa. No estimates were provided for 4 of the wells. The CGP stated that its estimates of the pool pressure decline rates are consistent with Petro-Canada's average estimate of 6.3 kilopascals (kPa) per month. Considering its conclusions in the Gulf Surmont Decision (*Decision 2000-22*) that artificial lift becomes increasingly difficult as the steam chamber pressure is decreased below 800 kPaa and that the minimum steam chamber pressure required for artificial lift to be technically feasible is in the range of 400 to 600 kPaa, the Board agrees with Petro-Canada that there is an urgent need to deal with the production of gas from the specific perforated intervals in the 10 wells listed in Appendix 1.

5.3 Feasibility of Artificial Repressuring

The Board notes that since the issuance of *Decision 2000-22*, no field tests have occurred to demonstrate the viability of repressuring a gas zone in a similar geologic setting to that at Surmont or Chard. While the Board acknowledges that repressuring of a depleted gas zone may be demonstrated to be a viable option in the future, it is not prepared to reconsider its previous conclusion in *Decision 2000*-22 and rely on repressuring until it has been proven that its implementation is both feasible and practical on the basis of field data.

5.4 Economics and Public Interest

The Board agrees with Petro-Canada that in this case the relevant measure of economic impact is the value of bitumen that could be sterilized relative to the cost of deferred gas production. Petro-Canada's evidence indicated the potential economic impacts of allowing a pressure decline of 1050 kPa and suggested that a linear extrapolation to reflect smaller pressure changes would be appropriate. Therefore, a pressure drop of 75 kPa—as the estimated result of one year of continued gas production—would have the following impacts on a single 30 000 barrel per day SAGD project (all money values discounted at 10 per cent):

- about 2 million barrels of bitumen would not be recovered;
- operating costs would increase by almost $3 million; and
- Crown royalties and pre-tax cashflow would be reduced by about $7 million.

With the potential for four such projects ultimately being undertaken in Chard, the magnitude of combined economic losses (royalties, taxes, and corporate profits) could be several times those listed above. Furthermore, the potential combined economic losses could be significantly greater if the decline in reservoir pressure were to proceed beyond the commercial viability of any bitumen production at Chard.

On the other hand, the combined value of before-tax cashflow and royalties from all future gas production at Chard would be about $40 million when discounted at 10 per cent. Deferring this income stream for one year would imply a loss in terms of the time value of money of about $4 million, again with a discount rate of 10 per cent. Notwithstanding the CGP's reservations about the future commercial viability of SAGD development at Chard, the Board believes that it would be imprudent to potentially jeopardize a significant bitumen resource.

5.5 Submission of Pressure Data

The Board notes that during the interim hearing Petro-Canada raised a concern that a number of pressure points used in the CPG's submission were not in the public domain. If these data have in fact not been submitted to the public domain, the Board shares Petro-Canada's concern. Section 11.120 of the Oil and Gas Conservation Regulations states that the licensee of a well shall supply to the Board each pressure and deliverability test made on the well. This means that all pressure and deliverability test data that are collected must be submitted to the Board, including any data over and above the minimum requirements of EUB *Guide 40*.[4] However, as stated in *Guide 40*, only those tests conducted under controlled conditions need to be submitted to the Board. A casual reading of a wellhead pressure with a portable dial gauge or a pumping fluid level does not have to be submitted. Likewise, a test that failed and has no useful information does not have to be submitted, with the exception of drill stem tests, where all tests must be submitted including misruns. If there are doubts or questions about whether data should be submitted, the EUB should be contacted for direction.

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[4] EUB *Guide 40: Pressure and Deliverability Testing Oil and Gas Wells—Minimum Requirements and Recommended Practices,* May 1999.

To ensure that all participants of the main hearing have access to all pertinent nonconfidential pressure data, the Board directs that all pressure tests taken in the Leismer Field and Chard area not currently in the public domain be submitted to the EUB in accordance with *Guide 40* by September 4, 2001. Any company submitting pressure data shall also provide the Board and any relevant applicant or intervener to the main hearing with a listing of any pressure tests filed. Noncompliance with the submission requirements outlined in the guide will result in consequences that escalate in severity, consistent with the EUB's enforcement policy.

DATED at Calgary, Alberta, on August 2, 2001.

ALBERTA ENERGY AND UTILITIES BOARD

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

B. T. McManus, Q.C.
Board Member

C. A. Langlo, P.Geol.
Acting Board Member

APPENDIX 1 McMURRAY GAS ZONES TO BE SHUT IN

	Licensee	Unique Well ID	Perforated Interval (mKB)
1	Rio Alto	00/12-35-079-07W4/0	348.5 - 350.0
2	Rio Alto	00/06-20-080-06W4/0	285.5 - 288.0
3	Rio Alto	00/10-27-080-06W4/0	245.7 - 250.2, 251.8 - 252.4
4	Rio Alto	00/11-28-080-06W4/2	284.0 - 296.0
5	Rio Alto	00/07-13-080-07W4/0	309.5 - 312.5, 313.5 - 314.5, 315.0 - 316.5
6	Rio Alto	00/07-14-080-07W4/0	327.5 - 328.5
7	Calpine	00/08-07-081-07W4/0	386.0 - 388.0
8	Calpine	00/06-17-081-07W4/0	385.0 - 386.0
9	Northstar	00/11-13-081-08W4/0	445.5 - 446.5, 457.5 - 458.5
10	Northstar	00/10-14-081-08W4/0	459.0 - 460.5

APPENDIX 2

File No. 7000-1085793-01

June 4, 2001

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TO ALL OTHER INTERESTED PARTIES

Dear Sir or Madam:

APPLICATION NO. 1094706
INTERIM SHUT IN OF GAS PRODUCTION
CHARD AREA
PETRO-CANADA OIL AND GAS

This letter deals with:

- the Alberta Energy and Utilities Board's (EUB or Board) decision to conduct a hearing in order to reconsider its earlier decision of April 26, 2001 in which it denied Petro-Canada Oil and Gas' (Petro-Canada) application to issue an interim shut-in order of certain gas wells in the Chard area,
- the nature of the proposed hearing including identification of the participants, filing schedule, hearing dates and allotment of hearing time for participants, and
- a Board request to Petro-Canada for additional information.

Shut-In Request

The Board received an application dated May 25, 2001, from Petro-Canada requesting the Board to further consider an interim shut-in of 40 producing gas wells in the Chard area on the grounds that continued pressure depletion of gas pools overlying its bitumen resource would significantly impair the extraction of the bitumen or sterilize the resources. In the alternative, Petro-Canada asked that the Board establish a minimum operating pressure for each well; if the pressure declined below the minimum, the well would be shut-in. Petro-Canada provided additional pressure data in its interim shut-in request and also referred to the information in its January 29, 2001application in support of its application.

Petro-Canada invoked sections 42 and 43 of the *Energy Resources Conservation Act* (ERC Act) as the basis of its application. It submitted that the Board erred in its decision of April 26, 2001 by denying Petro-Canada's earlier shut-in request because the energy statutes require the Board to fulfill a conservation and prevention of waste duty, on an interim as well as permanent basis. It argued that sufficient evidence was presented regarding the negative impact of continued gas production on the recovery of bitumen resources to enable the Board to shut-in the gas wells on an interim basis. It also contended that the Board's decision of April 26, 2001, constituted an "order or direction" under section 43 of the ERC Act in circumstances where the Board failed to hold a hearing. The result, it submitted, was that it was entitled to have its application considered at a hearing.

The Board also received a joint submission from counsel on behalf of Calpine Canada Natural Gas Company, Canadian Forest Oil Ltd., Paramount Resources Ltd. and Rio Alto Exploration Ltd. (the Chard Gas Producers) dated June 4, 2001, and a submission from Northstar Energy Corporation (Northstar) dated June 4, 2001. The Board did not receive a submission from Alberta Energy Company which owns one or two wells in the Chard area. Both the Chard Gas Producers and Northstar opposed Petro-Canada's request for a review or hearing of its application for the interim shut-in of 40 gas wells. They argued that the Board had made its decision on April 26, 2001, and it would be unfair to re-open the issue, especially in light of the complex and detailed evidence that would be required. They expressed a strong concern that there would not be adequate time to prepare a full and proper technical response to the interim shut-in application and questioned the urgency of the circumstances advanced by Petro-Canada. Northstar noted that Petro-Canada had waited eight months from the Gulf Surmont decision (D 2000-22) and three years from the Gulf Surmont Inquiry Report to make this interim application. These interveners maintained that they would suffer significant financial losses if they were unable to take the benefit of their considerable existing investment in the gas wells. They contended that the matter could only be properly considered at the main hearing.

The Chard Gas Producers submitted that the Board did not have jurisdiction to make an interim shut-in order because it was an extraordinary remedy and no specific statutory provision in the energy statutes sanctioned such an exercise of power. Further, they argued that the decision to deny the initial shut-in request was essentially an interlocutory decision and that section 43 of the ERC Act cannot be used in this context.

The Board has instructed me to advise that it has thoroughly reviewed the submissions of the parties to this application and has concluded that it will conduct a hearing to consider Petro-Canada's interim shut-in application. The Board believes that the conservation issue raised by the interim application merits a reconsideration of its earlier decision and that the most efficient means to conduct the reconsideration is through a hearing. The matter of potential impairment or sterilization of the recovery of bitumen resources is a fundamental concern of the Board. The Board notes that a considerable length of time will be required to conduct a hearing and issue a decision on the main application. As a result, the decision to shut-in or not to shut-in on an interim basis is a substantive one which may have serious conservation consequences. In these circumstances, the Board does not view its decision to conduct a hearing to reconsider the matter as similar to the review it might give a procedural or interlocutory matter such as a decision to grant or not grant an adjournment, or to set an initial hearing date, or to hold a combined hearing.

It is the Board's view that sufficient authority is found in section 15 of the ERC Act and section 3(5) of the Oil Sands Conservation Act Regulations (OSC Regulations) to issue an interim shut-in order if it is determined that one is required. Section 15 provides that the Board may do all things that are necessary or incidental to the performance of its duties, while section 3(5) of the OSC Regulations specifically states that the Board may "… make any order or directive it considers necessary to effect the conservation of the crude bitumen in any particular case." The plain meaning of both provisions, in the context of the Board's conservation mandate, support the Board's conclusion that it possesses the requisite authority to shut-in gas wells in the Chard area on an interim basis, if it so decides.

Hearing Process

As indicated, the Board will hold a hearing to determine whether 40 gas wells in the Chard area should be shut-in, pending the outcome of the main hearing. The Board acknowledges that an interim shut-in application of this nature must, necessarily, be somewhat constrained in terms of the amount and nature of the evidence, timing considerations, and the number of parties who will participate. Accordingly, the Board directs that the following parties (who are the owners and/or operators of the subject wells) may intervene in the Petro-Canada's interim shut-in application:

- Calpine Canada Natural Gas Company
- Canadian Forest Oil Ltd.
- Paramount Resources Ltd.
- Rio Alto Exploration Ltd. (the Chard Gas Producers)
- Alberta Energy Company Ltd.
- Northstar Energy Corporation

The hearing will held over two and one-half days commencing on Tuesday, July 3, 2001 at 1:00 p.m. The location will be announced shortly. Parties shall comply with the following filing schedule:

Deficiency Letter to Petro-Canada and	
Notice of Hearing (this letter)	June 5, 2001
Deficiency Response	June 13, 2001
Interveners' submissions	June 27, 2001

Hearing dates	July 3, 4 and 5, 2001

At the hearing, participants will be limited in the amount of time allowed to present their positions. The following allotment of time is proposed as an outline; the Board will strive to be flexible and fair to all parties as the hearing unfolds.

Petro-Canada Direct Evidence	1.5 hr.
Interveners' Cross-Examination	5.0 hr.
Board Staff and Board Questioning	0.5 hr.
Interveners' Direct Evidence	2.0 hr.
Petro-Canada Cross-Examination	5.0 hr.
Board Staff and Board Questioning	0.5 hr.
Petro-Canada Argument	1.0 hr.
Interveners' Argument	1.5 hr.

Additional Information
The Board has reviewed the present Petro-Canada application with a view to deficiencies. The EUB requires that fourteen copies of the following additional information be submitted by June 13, 2001, with copies to the above described parties by the same date:

1. On Page 6 of the application, Petro-Canada references a quote from EUB *Decision 2000-22* that states, "*The Board accepts that the evidence provided by Petro-Canada from its Chard leases is analogous to Gulf's Surmont leases based on its proximity and the similar geologic character of the McMurray Formation."* The EUB notes that the evidence provided by Petro-Canada at the Surmont Hearing was for its Chard A Bitumen Prospect. Briefly comment on the applicability of this evidence to the remainder of Petro-Canada's Chard leases.

2. On Page 8 of the application, it states that the calculated volume weighted average pressure of all the gas pools listed in Table 1 is 670 kPaa. On Table 1, the calculated volume weighted average pressure of all the pools is shown to be 854 kPaa in August 2000 and 732 kPaa in January 2001. For the calculated volume weighted average pressure of 670 kPaa, provide the date of this pressure value and the data on which it is based including all calculations.

3. For the gas pools listed in Table 1 of the application, provide an estimate of the monthly pressure decline rate for each pool and an aggregate volume weighted average monthly pressure decline rate for all the pools.

4. On Page 9 of the application, Petro-Canada requests that, if the Board is not prepared to shut in all Category 1 and 2 wells, the Board direct the shut in of wells that do not demonstrate a well pressure in excess of 1200 kPaa (i.e., minimum operating pressure).

- Briefly elaborate on the basis for a 1200 kPaa minimum operating pressure.
- Comment on the need for segregated zone pressures for Category 2 wells.
- For wells/zones that do not have recent pressure measurements, comment on the timing of conducting and submitting pressure tests for these wells/zones.
- Comment on the need and frequency for pressure monitoring of wells/zones above the requested 1200 kPaa minimum operating pressure.
- Provide a list of the most recent pressure measurement (including the test date) for each well/zone requested to be shut in and, where possible, an estimate of the current pressure and monthly pressure decline rate.

5. For Appendix 3 of the application, summarize the criteria used to determine whether or not a pressure measurement is "selected".

6. Provide a summary analysis showing the following:

- Annual bitumen production if the interim order were granted.
- Annual bitumen production at successively lower reservoir pressures, under the assumption that the interim order were not granted.
- The net present values of the bitumen volumes that could potentially be sterilized at successively lower reservoir pressures if the interim order were not granted.
- The net present value of the gas that would be shut-in if the interim order were granted.
- The net present value of the gas that would be shut-in at successively lower minimum operating pressures.
- The relevant assumptions that are used in the above analyses.

If you have any questions regarding the above, please contact the undersigned at 297-7402 or Ken Schuldhaus at 297-3572.

Yours truly,

Douglas A. Larder
Board Counsel

Appendix 10 EUB Decision Report Regarding Franco-Nevada Interim Shut-in Request

ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

FRANCO-NEVADA MINING CORPORATION
INTERIM SHUT-IN OF GAS PRODUCTION
00/10-23-076-07W4M/0 WELL **Decision 2001-64**
LEISMER FIELD **Application No. 1095081**

1 INTERIM DECISION

Having considered the evidence submitted to the interim hearing, the Alberta Energy and Utilities Board (EUB/Board) is not persuaded that continued production of Wabiskaw gas from the 00/10-23-076-07W4M/0 well (10-23 well) in the interim period to the main hearing of applications scheduled to commence on November 13, 2001, would have a significant impact on bitumen recovery, the costs of recovering the bitumen, and the economic desirability of a bitumen project. Accordingly, the Board denies the subject application.

This interim decision should not be considered as conclusive or permanent with regard to the issues to be addressed at the main hearing. An interim decision necessarily means that the Board did not have the benefit of the entirety of the evidence and argument that will ultimately be made available to it, nor was it in a position to assess the merits based on the totality of evidence. Accordingly, the Board will not be bound by the above interim decision.

2 INTRODUCTION

2.1 Background

On September 8, 2000, Franco-Nevada Mining Corporation (Franco-Nevada) applied (i.e., Application No. 1086353), pursuant to Section 42 of the Energy Resources Conservation Act (ERCA), for a review of two Anderson Exploration Ltd. (Anderson) applications for approval to produce gas that were previously approved by the EUB. Franco-Nevada submitted that Wabiskaw gas production from the 10-23 well and 00/04-04-076-06W4M/0 well may be detrimental to the recovery of bitumen from its Leismer oil sands lease due to either pressure reduction or the influx of water. Franco-Nevada's Leismer oil sands lease is located in the southeast quarter of Township 76, Range 7, West of the 4th Meridian.

On March 20, 2001, Franco-Nevada requested that the Board shut in the 10-23 well on an interim basis pending the Board's ultimate disposition of related applications by Anderson for approval to produce gas in the area of Franco-Nevada's oil sands lease. On April 26, 2001, the Board denied Franco-Nevada's application for the interim shut-in of the 10-23 well.

2.2 Application and Interventions

On June 5, 2001, Franco-Nevada requested that the Board review at a hearing its April 26, 2001, decision in which it denied Franco-Nevada's application for the interim shut-in of the 10-23 well. The Board subsequently received a submission from Anderson, dated June 8, 2001, opposing Franco-Nevada's request for a hearing. Anderson submitted that Franco-Nevada had not provided any new evidence that would justify the reversal of the Board's earlier decision.

On June 12, 2001, the Board issued its decision (Appendix 1) to conduct a hearing to consider Franco-Nevada's application for the interim shut-in of the 10-23 well.

2.3 Hearing

A public hearing of the subject application was held on July 9 and 10, 2001, in Calgary, Alberta, before J. D. Dilay, P.Eng., B. T. McManus, Q.C., and C. A. Langlo, P.Geol. A list of those who appeared at the hearing is provided in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Franco-Nevada Mining Corporation (Franco-Nevada) D. C. Edie	K. Bygrave, P.Geol., Consultant M. Carlson, P.Eng., of Applied Reservoir Engineering Ltd. P. Collins, P.Eng., Consultant G. Waterman
Anderson Exploration Ltd. (Anderson) L. M. Sali, Q.C.	P. Harvey, P.Eng. K. Kingsmith L. Piedimonte A. Vink, P.Eng.
Alberta Energy and Utilities Board staff M. E. Connelly, P.Geol. G. W. Dilay, P.Eng. K. M. Johnston D. A. Larder K. F. Schuldhaus, P.Eng.	

3 JURISDICTION OF THE BOARD TO ISSUE AN INTERIM SHUT-IN ORDER

The Board explained its position on the power to grant interlocutory shut-in orders and the appropriate test for such action in *Decision 2001-63*, issued on August 2, 2001. It concluded that the common law tripartite test for interlocutory injunctive relief was not strictly applicable to such applications before the Board because the Board's legislative responsibility to conserve energy resources in the public interest was the paramount consideration, not the parties' private interests. In making this determination, the Board also rejected the argument that it possessed the requisite authority to compel an applicant to provide an undertaking for damages to gas producers whose production was curtailed pending the main hearing on a shut-in application. A fuller discussion of this issue is found in *Decision 2001-63*.

4 ISSUES

The Board considers the issues with regard to the subject application to be as follows:

- geological interpretation,
- effect of associated gas production on bitumen recovery by steam-assisted gravity drainage (SAGD), and
- economics and public interest.

5 VIEWS OF THE BOARD

Given the interim nature of the subject application and the need to issue a timely decision, this report contains only the views of the Board and not the views of the hearing participants, as is the Board's normal practice.

5.1 Geological Interpretation

On the basis of the information currently available, the Board believes that Wabiskaw gas at the 10-23 well may be in communication with underlying bitumen through an intervening water leg within a localized Wabiskaw channel sand. It appears that the channel sand has downcut and removed the uppermost McMurray deposits in the area of the 10-23 well.

The Board accepts that pressure depletion due to gas production from the 10-23 well is shown to have reduced the pressure at the nonproducing 03/10-14-076-07W4/0 well (10-14 well). The Board believes that the available information demonstrates that the gas zone in the 10-23 well may be in indirect pressure communication through a water zone with the Wabiskaw gas at the 10-14 well on the Franco-Nevada oil sands lease and therefore is in communication with Wabiskaw bitumen on the Franco-Nevada lease.

Furthermore, based on the highly variable nature of the intervening sediments, the lack of any extensively correlatable mudstone units, and the unpredictable nature of channel environments, the Board believes that there is potential for vertical communication between the Wabiskaw and McMurray channel sands on the Franco-Nevada lease. Consequently, Wabiskaw gas at the 10-23 well may be in potential communication with Wabiskaw and McMurray bitumen on the Franco-Nevada lease. Additionally, the Board believes that the bitumen within the Wabiskaw and McMurray sands on the Franco-Nevada lease is of sufficient quantity and quality to warrant consideration for protection pending the outcome of the main hearing.

5.2 Effect of Associated Gas Production on Bitumen Recovery by SAGD

Franco-Nevada used reservoir simulation to assess the impact of associated gas production on bitumen recovery by SAGD. The simulation results submitted by Franco-Nevada for a single SAGD well pair showed that the bitumen recovery would be reduced from 383 300 cubic metres (m^3) to 381 100 m^3 when the pressure was reduced from 2000 kilopascals absolute (kPaa) to 1000 kPaa. This is a predicted reduction in bitumen recovery of only 0.6 per cent. Considering the uncertainties involved in reservoir simulation, the Board considers this to be an insignificant reduction. Furthermore, this reduction in bitumen recovery is for a 1000 kilopascal (kPa) pressure drop. Franco-Nevada and Anderson estimated the current rate of pressure decline for the region of influence containing the 10-14 and 10-23 wells to be 275 kPa per year and 240 kPa per year respectively. If one assumes it will take the Board in the order of a year to conduct the main hearing and issue its decision, a more appropriate pressure drop to use for this interim review would be 260 kPa, rather than 1000 kPa. If one used a linear interpolation, the predicted reduction in bitumen recovery of 0.6 per cent would be further reduced to about 0.15 per cent. Pressure measurements taken on the 10-14 and 10-23 wells in May 2001 indicated pressures of 1887 kPaa and 1458 kPaa respectively, for an average pressure of 1673 kPaa. Based on an estimated pressure decline rate of 260 kPa per year, the average pressure in one year would be about 1415 kPaa. This pressure is above the 800 kPaa pressure level that the Board concluded in *Decision 2000-22* makes artificial lift more difficult. The Board does not believe that Franco-Nevada has demonstrated that continued gas production from the 10-23 well for the interim period would result in a significant loss in bitumen recovery.

Notwithstanding this conclusion, the Board believes that it is necessary to consider the economic impacts that could result from continued gas production from the 10- 23 well in order to properly assess the public interest.

5.3 Economics and Public Interest

The Board notes that the bulk of Franco-Nevada's technical evidence describes its Leismer lease as a likely prospect for the application of SAGD technology. For example, with a gas price of $3.50 per gigajoule and an oil price of $16.40 per barrel, Franco-Nevada calculated an internal rate of return for a phased project of 186 well pairs to be in excess of 30 per cent. Notwithstanding the reservations expressed by Anderson regarding several costs that were overlooked by Franco-Nevada, the Board does not dispute that should SAGD technology live up to expectations, the Franco-Nevada lease is a potential candidate for its application.

Franco-Nevada submitted an analysis of the effects on SAGD performance of pressure depletion through gas production from the 10-23 well. A comparison of the forecast results from operating a well pair in a 40 m pay zone with a reservoir pressure of 2000 kPaa (Table 5-16 of Exhibit 5) and operating the same well pair at a pressure of 1000 kPaa (Table 5-18 of Exhibit 5) indicates the following:

- With lower reservoir pressure, total operating costs would increase marginally on an undiscounted basis ($12.8 million compared to $11.1 million), and when discounted at 10 per cent, operating costs would be virtually the same, at about $8.1 million.

- On an undiscounted basis, provincial royalties amended to remove production costs would decline modestly, from about $6.7 million in the higher pressure case to $6.2 million in the lower pressure case, while applying a discount rate of 10 per cent would imply a drop in royalties from some $4.6 million with higher reservoir pressure to $3.7 million with reservoir pressure declining to 1000 kPaa.

- With a discount rate of 10 per cent, pre-tax corporate profits would decline from $13.6 million to $10.4 million.

- The combined economic losses—comprising royalties, taxes and corporate profits—could be in the order of $4 million per well pair at a discount rate of 10 per cent.

The Board believes that the above estimates of impacts are high, as they are based on a reservoir pressure drop of 1000 kPa. Since the pressure decline in the absence of granting the interim shut-in order would only be about 260 kPa per year, the Board believes that the potential negative impacts per well pair would be far less than those shown above. Therefore, assuming a linear relationship between pressure decline and economic losses, the combined economic losses from not granting the interim shut-in order could be in the order of $1 million per well pair. However, the Board notes that the nature of the combined economic losses is largely related to the prospective timing of the revenues from production, rather than either the ultimate volume of bitumen recovery or the total costs of recovering it, both of which would be approximately the same with or without the granting of the interim approval. While the Board acknowledges that the timing of revenues and costs is a relevant economic and public-interest issue, the Board is not persuaded at this time that the impacts described by Franco-Nevada are significant enough to have a material effect on the economic desirability of the Franco-Nevada lease. The Board is prepared to hear discussion of these issues in the main hearing.

DATED at Calgary, Alberta, on August 2, 2001.

ALBERTA ENERGY AND UTILITIES BOARD

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

B. T. McManus, Q.C.
Board Member

C. A. Langlo, P.Geol.
Acting Board Member

APPENDIX 1

File No. 7000-1039410-01

June 12, 2001

Don Edie
Carscallen Lockwood
1500, 407 – 2 Street SW
Calgary AB T2P 2Y3
Fax: 262-2952

Lenard Sali
Bennett Jones
4500, 855 – 2 Street SW
Calgary AB T2P 4K7
Fax: 265-7219

Dear Sirs:

RE: APPLICATION NO. 1095081
INTERIM SHUT IN OF GAS PRODUCTION
10-23-76-7W4M WELL
LEISMER FIELD
FRANCO-NEVADA MINING CORPORATION LIMITED

1 Shut-In Request

The Alberta Energy and Utilities Board (EUB/Board) received a letter dated June 5, 2001, from Franco-Nevada Mining Corporation Limited (Franco-Nevada) requesting that the Board review its decision of April 26, 2001, in which the Board denied Franco-Nevada's application for the interim shut-in of Anderson Exploration Ltd.'s (Anderson) 10-23-76-7W4M well (10-23 well). Franco-Nevada seeks an order from the Board shutting-in the 10-23 well on an interim basis because of the potential harm to the recovery of its bitumen resources underlying the 10-23 well. It argued that the balance of economic interests favours the shut-in of the 10-23 well. Franco-Nevada referred to its earlier letter and supporting materials of March 20, 2001, and provided an additional letter dated June 11, 2001. It submitted that the Board should review its earlier decision by way of a hearing. Initially, Franco-Nevada proposed that its review be held in conjunction with the scheduled hearing regarding Petro-Canada Oil and Gas' (Petro-Canada) application for similar interim relief in the Chard area. In its letter of June 11, 2001, Franco-Nevada withdrew this request for a combined hearing.

Anderson opposed the request for a review by way of its letter dated June 8, 2001, maintaining that Franco-Nevada had not provided any new evidence that would justify the reversal of the Board's earlier decision. It pointed out that there are significant differences between Franco-Nevada's application and Petro-Canada's application in terms of the geology and the quality and economics of the bitumen reserves in question. Anderson argued that it would be inappropriate for the Board to consider the 10-23 well in isolation from Anderson's existing gas well production applications in the area as the evidence related to the 10-23 well will be directly related to Anderson's other wells. It proposed that the shut-in application be heard concurrently with Anderson's gas production applications at an early date.

The Board has deliberated on this matter and instructed me to advise you that it will conduct a review of its earlier decision not to impose an interim shut-in of the 10-23 well. The Board considers that its April 26, 2001 decision, based on its view that the evidence would be too detailed and complex for an interim decision, does not squarely address the issue of potential irreparable harm to the recovery of the bitumen resource, in the present circumstances. Franco-Nevada's main application for a permanent shut-in is part of the combined hearing outlined in the Board's letter of April 26, 2001. A considerable amount of time will elapse before a decision is issued on the main application. The Board is concerned that the extraction of the bitumen may be negatively affected by the continued production of the 10-23 well during this period. Accordingly, the Board will hold a hearing to consider the interim shut-in of the 10-23 well, utilizing the best evidence available at this time.

The Board does not accept, for the purposes of an interim shut-in application of the 10-23 well, that it is necessary to evaluate the several pending applications by Anderson for gas production. It is the producing 10-23 well that has been specifically identified by Franco-Nevada as posing a direct and immediate threat to its bitumen resource. Anderson's other wells are not producing at this time and do not present the same present concern.

Hearing Process

The Board directs that the parties to Application No. 1095081 are Franco-Nevada and Anderson. The filing and hearing schedule is as follows:

Notice of Hearing and Deficiency Letter to Franco-Nevada	June 12, 2001
Deficiency Response by Franco-Nevada	June 20, 2001
Intervention Submission by Anderson	July 4, 2001
Hearing	July 9 and 10, 2001

The hearing of Application No. 1095081 will be held at the offices of the National Energy Board (2nd floor hearing room) located at 444 – 7 Avenue SW, Calgary, and will commence on July 9, 2001, at 1:00 p.m.

At the hearing, participants will be limited in the amount of time allowed to present their positions. The following allotment of time is proposed as an outline; the Board will strive to be flexible and fair to all parties as the hearing unfolds.

Franco-Nevada Direct Evidence	0.5 hr.
Anderson Cross-Examination	2.0 hr.
Board Staff and Board Questioning	0.5 hr.
Anderson Direct Evidence	0.5 hr.
Franco-Nevada Cross-Examination	2.0 hr.
Board Staff and Board Questioning	0.5 hr.
Franco-Nevada Argument	0.5 hr.
Anderson Argument	0.5 hr.

Additional Information
The EUB requires that Franco-Nevada provide fourteen copies of the following additional information by June 20, 2001, with a copy to Anderson by the same date.

1. On Page 5 of the March 20, 2001 submission, it states that Franco-Nevada's analysis indicates that low pressures significantly reduce bitumen recovery and that the preliminary results of this analysis are shown in Figure 5. Briefly elaborate on the basis of Figure 5 and its applicability to gas production from the 10-23 well.

2. Provide the following for the gas pool containing the 10-23 well:

    - A listing of all the wells in the pool.
    - A summary of all the pressure measurements taken at each well in the pool including the test date.
    - An estimate of the current pool pressure and monthly decline rate.

3. Provide a net gas pay map for the pool containing the 10-23 well and a net bitumen pay map for the area potentially impacted by gas production from the 10-23 well, including the relevant cutoffs used to generate these maps.

4. Provide a summary analysis showing the following:

    - Annual bitumen production if the interim order were granted.
    - Annual bitumen production at successively lower reservoir pressures, under the assumption that the interim order were not granted.
    - The net present values of the bitumen volumes that could potentially be sterilized at successively lower reservoir pressures if the interim order were not granted.
    - The net present value of the gas that would be shut-in if the interim order were granted.
    - The net present value of the gas that would be shut-in at successively lower reservoir pressures.
    - The relevant assumptions that are used in the above analyses.

If you have any questions regarding the additional information described above, please contact Ken Schuldhaus at 297-3572.

Yours truly,

Douglas A. Larder
Board Counsel

pc: Interested Parties (see attached list)

Appendix 11 EUB Letter Regarding Closing Arguments

EUB Alberta Energy and Utilities Board
Calgary Office 640 – 5 Avenue SW Calgary, Alberta Canada T2P 3G4 Tel 403 297-8311 Fax 403 297-7336

EMAILED/FAXED

May 16, 2002

File No. 7000-1058461-01

COUNSEL FOR INTERESTED PARTIES
(list attached)

Dear Sir:

RE: ISSUES LIST AND RELATED MATTERS

I am attaching the final issues list, which has been prepared taking into account the written comments provided by parties on or before May 9, 2002. The Board directs that the Chard/Leismer participants use the outline with the described headings and sub-headings as a common template for written argument. If a party does not wish to provide argument on any of the topics contained on the issues list, it should simply indicate "no argument" under that particular heading or sub-heading. If a party believes that there is duplication or overlap with some of the topics and that it has already provided its views on a matter elsewhere in the template, it should simply indicate where its view is to be found. Issues that have not been identified in the outline may be addressed under the "Other" heading.

Parties will include an index at the beginning of the argument, using the headings and sub-headings of the issues list and incorporate a hyper-link function (click on the topic in the index and the related text in the document is accessed) on the electronic version of the argument. Fourteen paper copies, properly labelled and inserted in binders, and an electronic version must be provided to the Board. One paper copy and an electronic version must be given to the other parties.

The Board adopts the view urged upon it by many of the parties that 100 pages is a reasonable length for written argument (one-sided, double-spaced, on 11"x 8.5" paper, 1" margins with a size 12 font and Times New Roman script). Parties must use reasonable discretion if more pages are required to complete the argument.

It is the Board's intention to append the parties' written argument as a schedule to the decision report instead of providing the usual "Views of Parties" section in the body of the decision. The Board, of course, will reference and discuss the positions of the various parties in the reasoning leading to its conclusions on the many issues to be determined.

With respect to the timing of written argument, the Board directs that parties file their submissions on or before Friday, June 14, 2002. Reply argument must be filed on or before

Friday, June 28, 2002. The Board acknowledges that there are some outstanding matters which may influence final argument (proposed Encana witness panel, unfulfilled undertakings and commentary on core), however, it believes that sufficient time has been built into the filing dates to accommodate these matters. If that proves not to be the case, the Board will revisit the filing schedule.

If you have any questions, please contact the writer.

Yours truly,

Douglas A. Larder
Associate General Counsel

DAL/jh
Attachment
cc: Counsel for Interested Parties (list attached)

Counsel for Parties **Leismer/Chard Hearing** March 14, 2003

		Email Address	Phone No.	Fax No.
Linda White	Alberta Department of Energy	Linda.white@gov.ab.ca	780-427-6383	780-422-0692
Scott R. Miller	Petro-Canada Oil and Gas	srmiller@petro-canada.ca	265-8559	296-4910
Keith Miller	Burnet, Duckworth & Palmer	kfm@bdplaw.com	260-0153	260-0333
Don Edie	Carscallen Lockwood	edie@cllawyers.com	262-3775	262-2952
Al McLarty	Fraser Milner Casgrain	al.mclarty@fmc-law.com	268-7022	268-3100
Randall Block	Borden Ladner Gervais	rblock@blgcanada.com	232-9572	266-1395
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Dale Jordan	Seaton-Jordan & Associates Ltd.		266-5700	269-6569
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LEISMER FIELD AND CHARD AREA HEARING

ISSUES

1 EXTENT OF AFFECTED RESOURCES/RESERVES

a. Remaining Recoverable Gas Reserves

b. Bitumen Resource/Reserves
   i. Volume of recoverable bitumen resource
   ii. Cutoffs/parameters used to establish recoverable

2 RESERVOIR AND AQUIFER CONTINUITY

a. Regional-Scale Hydrogeology and Aquifer Systems
   i. Hydrogeologic and hydrodynamic models/studies
   ii. Gas pool pressure equalization/equilibration
   iii. Gas pools/aquifer simulation models

b. Geology of Wabiskaw/McMurray at Chard and Leismer
   i. Depositional models
   ii. Stratigraphic framework
   iii. Lateral continuity of mudstones/shales
   iv. Similarities/differences among Surmont/Chard/Leismer

c. Vertical Continuity
   i. Geological data
   ii. Pressure data for segregated gas zones
   iii. Piezometer data and models
   iv. Vertical permeability measurements and analogs

d. Lateral Continuity
   i. Geological data
   ii. Pressure data
   iii. Regions of influence (includes gas pools/aquifer mapping)

3 EFFECT OF ASSOCIATED GAS PRODUCTION ON SAGD BITUMEN RECOVERY

a. Field Experience

b. Studies

4 GEOMECHANICAL EFFECTS

a. Field Experience

b. Studies

5 FEASIBILITY OF ARTIFICIAL REPRESSURING

a. Field Experience

b. Studies

6 FEASIBILITY OF ARTIFICIAL LIFT

a. Field Experience

b. Studies

7 ECONOMICS

a. Economic Viability of SAGD Bitumen Development

b. Comparative Economics (Gas versus Bitumen)

c. Effect of Pressure on Bitumen Recovery Economics

8 INDIVIDUAL APPLICATIONS

9 REGULATORY PROCESS

a. Alternatives to Current Criteria/Process For Approval to Produce Gas

b. Criteria/Process For Dealing With Grandfathered Gas Wells

c. Data Collection/Submission Requirements (e.g., Pressure, Drilling Density, Coring, Seismic)

d. Alternative Resolution Processes

10 OTHER MATTERS

APPENDIX 12. THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
AEC Oil & Gas (AEC) R. M. Perrin	K. Aulstead, P.Geol. J. Biggs, P.Eng. N. Edmunds, P.Eng. D. Holmedal, P.Eng. L. Mattar, P.Eng., of Fekete Associates Inc. J. Shaw, P.Eng., of McDaniel & Associates G. Ward, of Ward Hydrodynamics Ltd.
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(continued)

THOSE WHO APPEARED AT THE HEARING (continued)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
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THOSE WHO APPEARED AT THE HEARING (concluded)

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Seaton-Jordan & Associates Ltd. (Seaton-Jordan) D. Jordan	D. Jordan
Alberta Energy and Utilities Board staff M. E. Connelly, P.Geol. G. W. Dilay, P.Eng. K. M. Johnston D. A. Larder J. R. MacGillivray, P.Geol. E. S. Mahadeo, P.Eng. K. P. Parks, Ph.D., P.Eng. K. F. Schuldhaus, P.Eng.	

APPENDIX 13. POTENTIAL FOR PRESSURE COMMUNICATION CATEGORIES

Category	Zone	Risk	Description
1	Wabiskaw C	Low	McM A regional mudstone is present throughout region of influence. Cannot be pooled laterally with gas in potential communication with channel bitumen.
2	Wabiskaw C	Low	Wbsk D regional shale greater than 0.5 m thick is present throughout region of influence. McM A and B regional mudstones are absent due to channelling. Cannot be pooled laterally with gas in potential communication with channel bitumen.
3	Wabiskaw C	High	Wbsk D shale is absent or less than 0.5 m thick throughout region of influence due to postdepositional erosive event related to transgression. McM A and B regional mudstones are absent due to channelling. Direct association with channel bitumen may not occur at well, but unpredictable nature of channel environment allows for possibility that direct association with channel bitumen could occur at some lateral distance.
4	Wabiskaw D	High	No regional mudstone is present between gas and underlying channel bitumen. Although stacked fluid contacts, such as G/B/G/B, may be present, lower gas zones are interpreted to be perched, trapped under local, areally restricted mudstones, such that upper gas zone may be in direct association with channel bitumen at some lateral distance.
5	Wabiskaw Channel	High	Direct association with Wbsk channel bitumen through top water. Possibility that direct association could occur at some lateral distance due to intersection of Wbsk channel bitumen with underlying McM channel bitumen.
6	McMurray A	Low	McM A regional mudstone is present throughout region of influence. Cannot be pooled laterally with gas in potential communication with channel bitumen.
7	McMurray B1	Low	McM B regional mudstone is present throughout region of influence. Cannot be pooled laterally with gas in potential communication with channel bitumen.
8	McMurray B1	High	McM B regional mudstone is absent due to channelling. Direct association with channel bitumen may not occur at well, but unpredictable nature of channel environment allows for possibility that direct association with channel bitumen could occur at some lateral distance. Although stacked fluid contacts, such as G/B/G/B, may be present, lower gas zones are interpreted to be perched, trapped under local, areally restricted mudstones, such that upper gas zone may be in direct association with channel bitumen at some lateral distance.
9	McMurray B1	High	Although McM B regional mudstone is present at well, there is the potential for direct association with channel bitumen at some lateral distance.
10	McMurray B2	Low	McM B regional mudstone is present throughout region of influence. Cannot be pooled laterally with gas in potential communication with channel bitumen.
11	McMurray Channel	High	McM B or McM A and B regional mudstones are absent due to channelling. Direct association with channel bitumen may not occur at well, but unpredictable nature of channel environment allows for possibility that direct association with channel bitumen could occur at some lateral distance.
12	Wabiskaw C, Wabiskaw D, McMurray A, or McMurray B1	Low	No regional mudstone or shale is present at well. However, underlying channel sands are wet and generally occur in area beyond zero edge of bitumen. Gas zones cannot be pooled laterally with gas in potential communication with channel bitumen.
13	Basal McMurray Channel or Shale	Low	Perforations are in a bitumen/basal water zone or a shale zone.