Decision 2007-056

Fisher and Moore Fields
Cold Lake Oil Sands Area

Applications for the Production and Shut-in of Gas from the Clearwater Formation

July 24, 2007

Alberta Energy and Utilities Board

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Decision 2007-056: Fisher and Moore Fields, Cold Lake Oil Sands Area

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ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

ENCANA, CNRL, AND HUSKY APPLICATIONS FOR THE PRODUCTION AND SHUT-IN OF GAS FROM THE CLEARWATER FORMATION FISHER AND MOORE FIELDS COLD LAKE OIL SANDS AREA

Decision 2007-056
Applications No. 1394112, 1409180, and 1481725

1 DECISION

Having considered all of the evidence, the Alberta Energy and Utilities Board (EUB/Board) concludes that in the area of application, production of gas from the Clearwater Formation (Clearwater) that is in pressure communication with potentially recoverable bitumen presents an unacceptable risk to bitumen recovery. Consequently, the Board

- denies Application No. 1394112 by EnCana Oil & Gas Partnership (EnCana) to produce Clearwater gas from the 14-31-68-4W4M (14-31) well;
- grants Application No. 1409180 by Canadian Natural Resources Limited (CNRL) to shut in Clearwater gas production from intervals in 18 wells listed in Table 1, effective September 1, 2007; and
- grants, in part, Application No. 1481725 by Husky Oil Operations Limited (Husky) to shut in Clearwater gas production from intervals in 24 wells and to not allow Clearwater gas production from intervals in 13 wells listed in Table 1, effective September 1, 2007. Four of the intervals that Husky requested be shut in will not be shut in by the Board.

An order requiring the shut-in of gas production or not allowing gas production will be issued by the Board shortly. The order will supersede any previously issued orders respecting commingled production of Clearwater gas from the intervals in the shut-in order. Since there is the potential to produce gas from intervals other than the intervals required to be shut in, there must be segregation in the wellbores between the shut-in intervals and other intervals open in the wellbores before production continues or commences from the other intervals.

2 INTRODUCTION

2.1 Applications

The Board considered the following applications:

- Application No. 1394112, submitted by EnCana for approval to produce gas from the Clearwater from the 14-31 well in the Fisher Field in the Cold Lake Oil Sands Area (OSA);
- Application No. 1409180, submitted by CNRL for an order shutting in gas production from the Clearwater from intervals in 18 wells in the Fisher and Moore Fields in the Cold Lake OSA (see Table 1); and

- Application No. 1481725, submitted by Husky for an order shutting in gas production from the Clearwater from intervals in 24 wells and not allowing gas production from the Clearwater from intervals in 13 wells in the Fisher Field in the Cold Lake OSA (see Table 1).

2.2 Interventions

CNRL objected to approval of Application No. 1394112. It was concerned that production of the 14-31 well would result in a decrease in the pressure in the underlying and adjacent bitumen that it owned, causing degassing of the bitumen, which it contended would result in a decrease in bitumen recovery.

Husky also objected to approval of Application No. 1394112 for reasons similar to those of CNRL.

EnCana objected to approval of Applications No. 1409180 and 1481725. As owner of the wells requested to be shut in, EnCana contended that the applicants failed to demonstrate that the recovery of commercial bitumen reserves in the Clearwater in the application area would be adversely affected by production of gas.

Imperial Oil Limited filed an intervention as an interested party. It provided information on its Cold Lake Cyclic Steam Stimulation Project.

2.3 Hearing

The Board held a public hearing in Calgary, Alberta, which commenced on February 20, 2007, and concluded on March 1, 2007, before Board Member J. D. Dilay, P.Eng. (Presiding Member) and Acting Board Members C. A. Langlo, P.Geol., and R. J. Willard, P.Eng. Those who appeared at the hearing are listed in Appendix 1.

At the close of the hearing, CNRL and Husky were required to complete several undertakings. Husky filed its undertaking responses on March 5, 2007, and CNRL completed the filing of its undertaking responses on March 8, 2007. The Board provided an additional written process to allow for the submission of model study input and output files. The final submission concerning the additional process was filed by EnCana on May 1, 2007, and therefore the Board considers the hearing record to have been closed on May 1, 2007.

3 BACKGROUND

On April 4, 2006, the EUB issued *Bulletin 2006-14*[1] regarding the regulatory process that it was going to use to deal with three applications before the EUB and the possible need for a broader bitumen conservation strategy in the Cold Lake and Peace River OSAs. The three applications were Applications No. 1394112 and 1409180, described in Section 2.1, and an application by Koch Exploration Canada Corporation (Koch) to shut in gas production from a well in the Peace River OSA. Koch subsequently withdrew its application. In *Bulletin 2006-14*, the EUB indicated that it would conduct a hearing on the EnCana and CNRL applications and that it would invite all interested parties to participate in the hearing by contributing technical evidence related to the

[1] Bulletin 2006-14: *Bitumen Conservation: Cold Lake Oil Sands Area—Clearwater Deposit, and Peace River Oil Sands Area—Bluesky-Gething Deposit,* April 4, 2006.

effect of associated gas production on bitumen recovery by cyclic steam stimulation (CSS). On October 3, 2006, Husky filed Application No. 1481725 (described in Section 2.1), and the Board joined this application to the EnCana and CNRL applications.

4 ISSUES

The Board considers the issues respecting the applications to be

- geology and reserves,
- effect of gas production on thermal bitumen recovery,
- feasibility of cold and thermally induced bitumen recovery,
- region of influence,
- disposition of the applications, and
- need for a broader bitumen conservation strategy.

5 GEOLOGY AND RESERVES

5.1 General Geology

The hearing participants were in general agreement with the interpretation of the Clearwater within the area of application. The targeted Clearwater sand was deposited within distinct stratigraphic sequences comprising both complex deltaic and multiple incised valley systems. The valleys are interpreted as trending southeast to northwest from Township 67, Ranges 3 and 4W4M to Township 69, Ranges 4 to 6W4M, and are incised into each other and the regional deltaic deposits, creating multiple cross-cutting relationships.

Within its Primrose area (Figure 1), CNRL interpreted three separate incised valley systems. These systems from oldest to youngest are the Blue, Yellow, and Orange Valley sequences. The Blue Valley sequence eroded into a pre-existing regional deltaic complex, then was subsequently partially eroded by the Yellow Valley sequence, and later was partially eroded by the Orange Valley sequence. Each incised valley sequence exhibits variation in sedimentary facies and distribution of reservoir quality. CNRL stated that this incision process has resulted in potential sand-to-sand avenues for pressure communication, as illustrated in Figure 2, which is adapted from the geological models submitted by CNRL and Husky, and illustrates the incision of the Blue and Yellow Valley sequences into the regional deltaic and shoreface deposits. This figure also illustrates the A, B, C, D, and E facies associations within the Blue Valley sequence as described by CNRL.

Within its Caribou lease (Figure 1), Husky interpreted a wide incised valley system, opening to the north-northwest and broadly differentiated into a central axis, flanked on the east and west by marginal valley deposits. Husky's main target area for thermal development is included in the central axis of the incised valley system that was the site of predominantly sand-rich deposition. Husky noted that the central sand-filled axis appeared to have merged into the marginal valley deposits without sharp lateral facies boundaries and that both facies are characterized by interbedded mud stringers. The valley system is incised into a regional deltaic muddy shoreface, which Husky referred to as the Western Regional Shale and the Eastern Regional Shale (Figure 2). The central sand-filled axis and the muddy valley margin deposit generally correlated with CNRL's Blue Valley sequence.

EnCana did not submit a general geological model of the Clearwater deposition. However, EnCana acknowledged that there were diverse and complex assemblages of lithofacies in the application area and submitted a detailed geological evaluation, including mapping and evaluation of gas, bitumen, and water zones.

5.2 Distribution and Continuity of Shales and Mudstones

5.2.1 Views of the Parties

CNRL recognized a continuous mudstone facies within its Blue Valley sequence, which it called the C and D muds. CNRL interpreted this unit to be a local vertical seal that was eroded to the east by the Yellow Valley sequence and terminated to the west by mud and sand onlap. CNRL stated that there was communication between the thick bitumen deposits above, below, and adjacent to the western boundary of the C and D muds. CNRL recognized another correlatable shale unit to the west of the Blue Valley sequence, which it included within its C2 sequence. CNRL interpreted the C2 unit to be a relatively muddy and fine-grained deposit and not a potential bitumen horizon.

Husky recognized a mud-rich interval within its incised valley system, which it noted was comparable to the CNRL C and D muds. Husky stated that this interval consisted of discontinuous mud stringers and mud clasts and merged into the central sand-rich axis without sharp lateral facies boundaries. Husky described this unit as a baffle shale with finite permeability and not as a laterally continuous shale barrier. To the west of its incised valley system Husky interpreted a western shale unit that had been progressively eroded within the incised valley system. Husky stated that this shale unit was likely a competent seal against vertical fluid migration where it had not been breached or completely eroded by the incised valley system. Husky's western shale was comparable to the shale within CNRL's C2 unit. Husky recognized no other continuous vertical permeability barriers.

EnCana also recognized the presence of a mud-rich deposit, which it referred to as the C and D mudstone within the eastern part of its mapped area. EnCana mapped bitumen net pay above and below this unit and stated that there was potential for this mudstone unit to be a local permeability barrier. It also stated that there could be communication between the bitumen overlying the mudstone and the bitumen adjacent to the mudstones along the western erosional edge. EnCana also recognized a mudstone unit to be present in the western part of its mapped area, but it did not submit a discussion of the depositional environment, lateral continuity, or sealing character of this mudstone. EnCana mapped the bitumen net pay present above and below this unit, which it referred to as the C–D mudstone.

5.2.2 Views of the Board

The Board notes that all parties recognize the presence of a mud-rich unit within the incised valley system in the eastern portion of their respective areas of interest. This unit is called the valley margin shale by Husky and the C and D muds by CNRL and EnCana. The Board agrees with CNRL, Husky, and EnCana that there is communication between bitumen above and adjacent to this mud-rich unit along its western edge. The Board agrees with CNRL and EnCana that there is potential for this unit to be a local permeability barrier. The Board notes that CNRL mapped this unit to be continuously greater than 10 metres (m) thick over a 12-section area.

The Board notes that all parties recognize the presence of a shale or mudstone in the western portion of their respective areas of interest. CNRL included this shale within its C2 deposit, EnCana referred to it as a C and D mudstone, and Husky called it the Western Shale. The Board agrees with Husky that this shale unit constitutes a permeability barrier where it has not been eroded. The Board believes that this is evidenced by the presence of gas and associated water in the Fisher Clearwater CC Pool, which is separated by this shale from the underlying gas of the Fisher Clearwater DD Pool.

5.3 Mapping of Gas Pools and Associated Water Zones

5.3.1 Views of the Parties

CNRL, Husky, and EnCana used neutron/density porosity log crossover and/or sonic log response to determine if there was gas pay in an interval. For thin gas zones, generally less than 1 m thick, all parties considered the neutron/density log approach to be an indication of gas pay.

To determine net gas pay thickness, CNRL used a cutoff of 50 per cent water saturation, calculated using Simandeaux and Archie equations. Husky determined its net gas pay thickness from log analysis by applying 20 per cent porosity and 50 per cent water saturation cutoffs. EnCana assigned net gas pay to intervals that had log resistivities greater than 10 ohm metres (ohm-m) and bitumen saturation less than 10 per cent from core data.

With respect to mapping, all parties used structural closure to determine the areal extent of the gas pools with gas located in structural highs and trapped by the overlying Clearwater shales. Both CNRL and EnCana submitted seismic amplitude maps. CNRL noted that seismic was used to help define the zero edges of its pools. However, EnCana stated that the seismic resolution on both structural values and amplitude anomalies was not conclusive evidence of pool edges.

5.3.2 Views of the Board

The Board notes that there was general agreement among the parties on the method of log analysis used to identify the presence of gas within a sand interval. The Board agrees with the use of neutron/density porosity log crossover and/or sonic log response to identify gas pay and accepts that the neutron/density log approach may also indicate gas pay. However, the Board believes that an interval with neutron/density log approach must also have log resistivity data, sufficient structural elevation, and proximity to proven gas reserves that support an interpretation of gas pay in order to be assigned gas pay. The Board agrees with the method CNRL used to determine net gas pay thickness.

The Board agrees with all parties on the use of structural closure to determine the areal extent of the gas pools and that the gas is located in structural highs and trapped by the overlying Clearwater shales. The Board notes that both CNRL and EnCana submitted seismic amplitude maps. However, the Board is influenced by EnCana’s statement that the seismic data submitted was not conclusive evidence of pool edges and therefore the Board does not rely on the seismic amplitude maps to supports its interpretation.

The Board does not believe that one applicant's maps can be used to represent all pools at issue in this hearing. The Board has reviewed the geological and engineering evidence submitted and, where supported by the data, has revised its net gas pay and associated water maps. To help clarify pooling changes, Figure 3 shows a comparison of the outlines of the EUB pools prior to the hearing and the new pool outlines determined as a result of the hearing. Figures 4, 5, and 6 compare the outlines of the gas pools and associated water zones as interpreted by CNRL, Husky, and EnCana and the Board's new gas pools and associated water zones. The outlines of the associated water zones are only shown where the water zones extend beyond the outlines of the gas pools. With respect to Husky's mapping of the associated water zones, Husky applied a clipping polygon around the data, which resulted in the water zones not being fully delineated.

New pool orders reflecting the pooling changes will be issued in due course.

The Board's interpretation of gas pool mapping and associated water zones is summarized as follows.

Fisher Clearwater A Pool (upper zone in wells AA/11-15, AA/1-22, and 10-22-67-5W4M)
The Fisher Clearwater A Pool was previously designated as a single-well gas pool. However, the Board agrees with the interpretations of CNRL and EnCana and has assigned gas pay to the AA/11-15 and AA/1-22-67-5W4/M wells. It has also isopached the gas pay in these wells with the gas pay in the 10-22-67-5W4M well. The Board agrees with EnCana on the areal extent of the pool and believes that the pool does not extend as far into adjacent undrilled areas as was interpreted by CNRL.

Fisher Clearwater PP Pool (lower zone in well 10-22-67-5W4M)
The Fisher PP pool is a single-well gas pool encountered by the 10-22-67-5W4M well. It has been assigned a drainage area of 150 hectares (ha). The Board has limited the southern extent of this gas pool based on its interpretation that there is no gas pay in the 11-15 or 1-22-67-5W4M wells.

Fisher Clearwater B Pool
The Board has revised its interpretation of the Fisher Clearwater B Pool to include wells in sections 13 and 14-70-5W4M and the 4-18 and 6-20-69-4W4M wells, similar to Husky's and EnCana's interpretations. The Board accepts the areal extent of the associated top water as submitted by EnCana because there are no wells drilled in section 33-69-5W4M to confirm the presence of the water zone in sections 32 and 33-69-5W4M, as interpreted by Husky.

Fisher Clearwater E Pool
CNRL did not include the 03/8-3-69-4W4M (03/8-3) and 5-10-69-4W4M (5-10) wells in its Fisher Clearwater E pool due to the thinning of the pay interval in the 10-35-68-4W4M (10-35) well, combined with low seismic amplitude east and west of the 10-35 well. However, it submitted a possible interpretation of the Fisher Clearwater E Pool extending into sections 3 and 10 of Township 69, Range 4. CNRL stated that it did not map the 10-33-68-4W4M (10-33) well with the wells in section 3 and 10-69-4W4M because the wells have significantly different pressures than those recorded at the 10-33 and 02/10-33 wells. It stated that pressures measured about one month apart indicated that there was a pressure difference of 345 kilopascals (kPa) between the 10-33 and 5-10 wells. Also, pressures measured only two days apart indicated that there was a pressure difference of 285 kPa between the 03/8-3 and 02/10-33 wells. EnCana stated that the initial pressure in the 10-33 well appeared to be lower than the virgin pressure by

more than gauge error, so there seemed to be pressure communication between the 10-33 well and the gas in sections 3 and 10-69-4W4M. EnCana interpreted that there were two lobes with a saddle in between them approaching the water or bitumen zone. Husky mapped the 10-33 well in the same pool as the 03/8-3 and 5-10 wells.

CNRL pooled the previously designated Moore Clearwater D Pool, containing the 11-6-68-3W4M (11-6) well, with the previously designated Fisher Clearwater E Pool based on pressure differences between the 11-6 well and surrounding gas pools, seismic, and pressure divided by the gas compressibility factor versus cumulative gas production (P/Z) plots. It noted that the pressure differences ruled out connection to the Moore Clearwater A pool and the P/Z plot ruled out connection to CNRL's single-well pool at 5-17-68-3W4M, while seismic data indicated that the 11-6 well was more likely connected to the Fisher E/F pool as mapped by CNRL.

EnCana interpreted the Fisher Clearwater E and D Pools to be separate pools and the Moore Clearwater A, B, and D Pools to be one pool. However, EnCana stated that the interpretation of these pools could have a non-unique solution; they could be mapped as by EnCana or CNRL or as designated by the Board.

The Board agrees with EnCana and Husky that the 10-33, 03/8-3, and 5-10 wells are in the same pool. The Board does not believe that the pressure differences indicated by CNRL are conclusive reasons for not including the 10-33, 03/8-3, and 5-10 wells in the same pool. The Board notes that even within the Moore B/C pool, as mapped by CNRL, there was a pressure difference of 250 kPa between the 7-16 and 15-29-68-3W4M wells on January 27, 2006.

The Board agrees with both CNRL and EnCana that there is gas pay in the 9-25-67-4W4M, AA/9-1, AA/15-1, AA/6-12, AA/8-12, 9-23, and 10-35-68-4W4M wells. The Board also notes that structural mapping based on the well control indicates that there is structural continuity between the pools previously designated as the Fisher Clearwater D and E Pools and the Moore Clearwater A and D Pools, with no geological evidence for pool separation. The Board therefore interprets the Fisher Clearwater D and E Pools and the Moore Clearwater A and D Pools to be a single-gas pool, which it will designate as the Fisher Clearwater E Pool.

With respect to the areal extent of the Fisher Clearwater E Pool and the associated water zone, the Board makes the following interpretations:

- Based on the logs of the 12-14 and AA/12-23-68-4W4M wells, the Board interprets bitumen pay with no associated gas pay because of a lack of crossover of the neutron/density logs and a lower structural position for the top of porosity in these wells. Therefore, the Board does not extend the gas pool to include these wells as mapped by EnCana. The Board notes that CNRL did not interpret gas in these wells.

- Based on the logs of the 5-4, 10-5, 14-5, and 1-8-69-4W4M wells, the Board interprets bitumen pay with no associated water at the top of the Clearwater sand because the resistivity is approaching or above 10 ohm-m. Also, based on a review of the core of the 10-5 and 1-8-69-4W4 wells, the Board does not interpret a water zone, because of high bitumen saturation to the top of the Clearwater sand. Therefore the Board does not extend the water zone associated with this pool into sections 5 and 8-69-4W4 as mapped by Husky.

- Based on the logs of the AA/3-28, 6-28, AA/12-28, 8-29, AA/10-29, 10-32, 02/10-32, AA/2-33, and AA/4-33-68-4W4M wells, the Board does not assign gas pay to these wells. The Board interprets these wells to be a continuation of the associated water zone because of the low log resistivity values and lack of neutron/density crossover.

Fisher Clearwater G Pool
The Board has revised its interpretation of the Fisher Clearwater G Pool and agrees with Husky and EnCana that this is a two-well pool that includes the 7-19 and 6-20-69-5W4M wells. The Board accepts the pool outline as submitted by Husky. Due to limited well control, the Board has not extended this pool into the undrilled section 21-69-5W4M, as submitted by EnCana.

Fisher Clearwater S Pool
The Board has revised its pool interpretation for the Fisher Clearwater S Pool to agree with the pool interpretations submitted by Husky and EnCana. The Board notes that Husky and EnCana generally agreed on the areal extent of the gas pool, but not on the extent of the associated water zone. The Board agrees with the areal extent of the associated water zone submitted by EnCana. The Board interprets the Clearwater interval in the 8-13-70-6W4M well as containing bitumen to the top of the Clearwater sand based on resistivity. Therefore the Board does not interpret the associated water zone to extend into section 13-70-6W4M as submitted by Husky.

Fisher Clearwater T Pool (upper zone in wells 5-13 and 8-14-69-6W4M)
The Board agrees with Husky and EnCana that the Fisher Clearwater T Pool is a two-well pool and has revised its pool interpretation to include the gas pay in the 8-14-69-6W4M well. Due to limited well control, the Board assigns overlapping drainage areas of 150 ha for each well.

Fisher Clearwater EE Pool (lower zone in wells 5-13 and 8-14-69-6W4M)
The Board agrees with Husky and EnCana that the Fisher Clearwater EE Pool is a two-well pool and has revised its pool interpretation to include the gas pay in the 8-14-69-6W4M well. Due to limited well control, the Board assigns overlapping drainage areas of 150 ha for each well.

Fisher Clearwater CC Pool (upper zone in wells 13-27, 16-28, 02/16-28, and 11-33-68-5W4M)
The Board’s interpretation of the extent of the Fisher Clearwater CC Pool differs from that of Husky and EnCana. The Board has not extended this pool into the undrilled section 3-69-5W4M. Since there is water below the gas in this pool, the Board believes that this pool is not connected to the underlying Fisher Clearwater DD Pool. The Board has not made any significant change to its pool interpretation.

Fisher Clearwater DD Pool (lower zone in wells 13-27, 16-28, 02/16-28 and 11-33-68-5W4M)
The Board interprets the gas zone and associated water zone of the Fisher Clearwater DD Pool to have the same areal extent as the overlying Fisher Clearwater CC Pool and has not made any significant changes to its pool interpretation.

Fisher Clearwater TT Pool

The Fisher Clearwater TT Pool is a single-well pool encountered by the 3-11-70-6W4M well and is assigned a drainage area of 150 ha. The Board does not interpret any gas pay in the 6-2-70-6W4 well and has used this well to define the southern limit of the pool.

Fisher Clearwater Undefined 052 Pool
The Board agrees with Husky and EnCana that the Fisher Clearwater Undefined (U/D) 052 Pool is a single-well pool encountered by the 8-26-69-5W4M (8-26) well. Although the initial pressure was depleted in the 8-26 well without the well being produced, the Board considers it to be a single-well pool separate from the Fisher Clearwater B Pool due to a 2 m difference in gas/water contacts. It is likely connected to the Fisher Clearwater B Pool through a water zone. The Board has not changed its pool interpretation.

Fisher Clearwater Undefined 093 Pool (wells 7-31, AA/10-31, 14-31, and AA/14-31-68-4W4)
The Board maps the Fisher Clearwater U/D 093 Pool to include the 7-31, AA/10-31, 14-31, and AA/14-31-68-4W4M wells and agrees with Husky and EnCana on the areal extent of the pool.

Fisher Clearwater Undefined 006 Pool (well 11-13-70-5W4M)
The Board agrees with Husky that the interval from 442.5 to 445 metres at kelly bushing (mKB) in this well is a single-well gas pool. The Board interprets the interval to be separated by shale from the overlying Fisher Clearwater B Pool. The Board has not changed its pool interpretation.

Moore Clearwater B Pool
The Board agrees with CNRL and EnCana that the gas pay in the previously designated Fisher Clearwater U/D 080 Pool (the 15-29-68-3W4M well) is continuous with the Moore Clearwater B Pool.

EnCana submitted that the Moore Clearwater A and Clearwater B Pools should be mapped as a single pool. From the structure map submitted by EnCana, the Board notes that the wells in section 33-67-3W4M and in sections 4, 5, and 6-68-3W4M are structurally 5 to 10 m lower than the nearby wells in the Moore Clearwater A and B Pools and the Fisher Clearwater E Pools. The Board believes that this defines a continuous structural low between the Moore Clearwater A and B Pools. The Board therefore continues to separate the Moore Clearwater A Pool from the Moore Clearwater B Pool.

The Board also notes that EnCana interpreted its combined Moore Clearwater A and B gas pool to extend into section 35-67-4W4M. The Board has reviewed the logs for the AA/8-1-68-4W4M (8-1) well and interprets bitumen pay with no associated gas pay because there is no neutron/density crossover or approach evident on the logs. The Board interprets the lack of gas pay in the 8-1 well to define the western edge of the Fisher Clearwater E Pool and has therefore not extended the pool into section 35-67-4W4M.

CNRL interpreted the 5-17-68-3W4M (5-17) well to be a single-well pool because recent pressures in the area show that the pressure at the well is 300 kPa higher than the pressure of the Moore Clearwater B Pool and 100 kPa higher than the pressure of Fisher Clearwater E Pool, and because there are significant structural lows based on seismic data between the 5-17 well and the Fisher Clearwater E Pool. CNRL stated that the well appeared to be a single-well pool connected to surrounding gas pools by bottom water. The Board does not believe that the pressure difference of 300 kPa indicated by CNRL is a conclusive reason for interpreting the 5-17 well as a single-well pool and agrees with EnCana that the well is in the Moore Clearwater B Pool. As stated previously, the Board notes that even within the Moore B/C Pool as mapped by CNRL, there was a pressure difference of 250 kPa between the 7-16 and 15-29-68-3W4M wells on January 27, 2006.

5.4 Mapping of Bitumen Net Pay

5.4.1 Views of CNRL

CNRL used a cutoff of 6 weight per cent bitumen with an average porosity of 32 per cent to determine bitumen net pay in the Clearwater. It acknowledged, however, that a bitumen net pay map using a 6 weight per cent cutoff could include intervals having up to 60 per cent water saturation. CNRL submitted net bitumen pay maps for all Clearwater intervals that it deemed potentially productive for the northern part of Township 66, Range 4W4M, and an area from the west half of Township 67, Range 2W4M, to the eastern half of Township 68, Range 5W4M.

CNRL submitted that in the Clearwater, intervals with greater than 10 m of bitumen pay had generally been targeted for CSS development, but that recent improvements in technology were expanding feasible development to intervals as thin as 7 m. CNRL provided production data from one of its production phases at Primrose for a portion of the area where the average bitumen thickness was 7 m. CNRL stated that wells in this area had produced 33 000 cubic metres (m^3)/well, with a cumulative steam-oil ratio of 5.0 using 600 m horizontal wells. CNRL also referred to a new phase where 1600 m horizontal wells had been drilled in about 8 m of reservoir, and it was expecting the wells to produce over 90 000 m^3/well.

5.4.2 Views of Husky

Husky used log analysis with cutoffs of 20 per cent porosity and 50 per cent water saturation to determine net bitumen pay. Husky preferred to use well log analysis rather than core to determine net pay thickness, since log data were sampled every 10 centimetres and were more representative of the reservoir, as opposed to irregularly spaced core sample analyses. Husky submitted net bitumen thickness maps for Township 69, Ranges 4 to 6W4M.

5.4.3 Views of EnCana

EnCana constructed its net pay maps using a bitumen saturation cutoff of 50 per cent pore volume. Where core was available, it used bitumen saturations determined from core analysis. Where only partial core was available, a comparison of core saturations with log resistivity was used to obtain a log resistivity cutoff for determining net bitumen pay. EnCana noted that a precise resistivity cutoff for 50 per cent bitumen saturation would be misleading in thick sands with thin interbedded mudstones, as the mudstones appeared to lower the resistivity value. It also stated that a reliable resistivity value could not be obtained where lithologies changed rapidly because of the limitations of logging devices. EnCana submitted net bitumen thickness maps covering the area from Township 67, Range 3W4M, to Township 70, Range 6W4M.

EnCana noted that the Clearwater sand could have significant amounts of pore lining clays, mudstone intervals, and calcite layers composed of both concretions and calcite cemented sandstones. EnCana stated that it had removed the calcite stringers from its net pay calculations and that by using a bitumen saturation cutoff of 50 per cent pore volume, the mudstone sequences were also removed from net pay.

5.4.4 Views of the Board

With respect to Husky's views, the Board interprets that cutoffs of 20 per cent porosity and 50 per cent water saturation would result in bitumen net pay equivalent to a 4 weight per cent bitumen cutoff map. The Board does not consider this to be representative of potentially recoverable bitumen. The Board also notes that the calcite cemented horizons within the Clearwater often exhibit porosities higher than 20 per cent and may meet Husky's cutoff for net bitumen pay, thereby overestimating the potentially recoverable bitumen for its mapped area.

With respect to EnCana's views, the Board notes that irreducible water associated with shales, whether as thin shale layers, pore lining clays, or mudstone clasts, would reduce the log resistivity readings within the bitumen zone. The Board is concerned that EnCana's use of a resistivity log cutoff to determine net bitumen pay when core is not available may underestimate the potentially recoverable bitumen.

The Board recognizes that the water saturation in bitumen zones of the Clearwater is generally higher than that of the McMurray and believes that this is in part due to immovable bound water associated with pore lining clays, as noted by EnCana. The Board believes that the bound water associated with pore lining clays contributes to the high pore volume of water in zones of apparently clean, porous bitumen saturated sand, seen in the Clearwater cores. The Board notes that the weight per cent bitumen calculation includes the total bitumen within the pore space of a reservoir and also accounts for the total amount of water, including clay bound water. The Board accepts as reasonable the calculation of net bitumen pay using weight per cent cutoffs. The Board believes that net bitumen thickness maps generated using a 6 weight per cent bitumen cutoff, as submitted by CNRL, provide a reasonable estimate of potentially recoverable bitumen.

The Board notes that the 6 weight per cent bitumen cutoff map provided by CNRL does not cover the entire application area. The Board believes that applications for production or shut-in of gas should be assessed with a consistent set of potentially recoverable bitumen maps. As a result, the Board has generated a map based on a cutoff of 6 weight per cent bitumen above the C-D mudstones and regional mudstones for the entire application area, as shown in Figure 7. The 6 weight per cent calculation was done using the equation provided in Appendix B2, page 187 of the *Athabasca Wabiskaw-McMurray Regional Geological Study*.[2]

Considering that CNRL has been producing Clearwater bitumen from an area where it interprets the average bitumen thickness to be 7 m, the Board considers a net bitumen thickness of 7 m to be an appropriate cutoff for determining potentially recoverable Clearwater bitumen by CSS.

6 EFFECT OF GAS PRODUCTION ON THERMAL BITUMEN RECOVERY

The issue of the effect of gas production on thermal bitumen recovery considered at this hearing differed from the issue considered at previous Board hearings in the Athabasca OSA (Athabasca). One difference is the thermal bitumen recovery methods involved: in this hearing

[2] EUB *Report 2003-A*: *Athabasca Wabiskaw-McMurray Regional Geological Study*, December 31, 2003.

the recovery methods were horizontal well cyclic steam stimulation (HWCSS) and hybrid steam-assisted gravity drainage (HSAGD),[3] while steam-assisted gravity drainage (SAGD) was the recovery method involved in the Athabasca hearings. A second difference is the location of the gas zones relative to the bitumen zone: in the area considered in this hearing, most of the gas zones were laterally offset from the bitumen that was requested to be protected, while in the Athabasca hearings the gas zones were vertically above the bitumen that was requested to be protected. A third difference is the reason for the concern about gas production: in this hearing the concern was that producing the gas zones would degas the bitumen and this would remove the solution gas drive mechanism, while in the Athabasca hearings the main concern was that producing the gas zones would result in low-pressure thief zones.

There was general agreement among the parties that gas production from the gas zones had caused pressure depletion in the bitumen zone and that in turn had caused solution gas to evolve from the bitumen and migrate to the gas zones. This agreement was based on the piezometer data, which had shown pressure drops of various amounts in the bitumen zone (discussed in Section 8). As well, the gas reserves estimated by material balance and decline analysis are significantly larger than the volumetric gas in-place for several of the gas pools involved in this hearing.

The disagreement among the parties was whether or not the gas production and resulting pressure depletion in the bitumen zone would have a significant detrimental effect on bitumen recovery by HWCSS or HSAGD. CNRL, Husky, and EnCana submitted model studies using the Computer Modelling Group’s STARS simulator to predict the effect of gas production on thermal bitumen recovery. CNRL submitted a 2-dimensional (2-D) model of a horizontal CSS well in its Primrose area. Husky submitted 2-D and 3-D reservoir flow models taken from a portion of a one-section geological model in its Caribou area. Husky modelled HWCSS and HSAGD using two wells (one SAGD well pair and one HWCSS well in the case of HSAGD). However, Husky was unable to get the 3-D model to run to completion. EnCana submitted two model studies: a 3-D generic model study for CNRL’s area and a 3-D field model for Husky’s Caribou area. The generic model involved a single CSS well in three different reservoir configurations—nonedge, flank, and edge—which are discussed in more detail later in this section. The field model involved about 85 sections that included an area where HWCSS and SAGD were modelled for three wells (three well pairs in the case of SAGD). EnCana referred to its field model as its piezometer model.

The parties presented quantitative estimates of the effect of gas production on bitumen recovery in two ways: in some instances they were presented as the difference in recovery factors between the cases with and without gas production, and in other instances they were presented as the difference in recovery factors as a percentage of the recovery factor for the case with no gas production. In this report the former presentation method is referred to as a percentile difference and the latter is referred to as a per cent difference in bitumen recovery. To illustrate, if the recovery factor for a case without gas production was predicted to be 20 per cent and the recovery factor for a comparable case with gas production was predicted to be 15 per cent, this

[3] HSAGD involves a combination of SAGD and HWCSS in which the HWCSS wells are located between the SAGD well pairs. Husky stated that it had applied to the EUB for approval to operate a pilot to test the HSAGD process at its Caribou oil sands lease. Husky indicated it considered the HSAGD process to be experimental and was relying on HWCSS as its backup bitumen recovery process if HSAGD were not successful.

could be presented as a 5 percentile difference (20 – 15) or as a 25 per cent difference ([20 – 15]/20 * 100) in bitumen recovery.

6.1 Views of CNRL

CNRL submitted that active solution gas drive was required for economic bitumen recovery from the Clearwater at Cold Lake. CNRL relied on field evidence, the technical literature, and reservoir simulation to support its view.

With respect to field evidence, CNRL contended that the presence and importance of solution gas in CSS bitumen recovery were provided by the observation of bitumen shrinkage by almost 50 per cent as gas came out of solution from a wellhead sample taken from an HWCSS well during the late-stage production phase, as well as the observation during CSS operations of stable gas-oil ratios (GORs) and low long-term pressures being maintained by solution gas exsolution. CNRL also noted that where the bitumen did not contain significant solution gas, such as at the pilot conducted at Hangingstone in Athabasca, CSS was much less effective than at Cold Lake.

With respect to the technical literature, CNRL stated that physical laboratory models and simulations indicated that solution gas contributed up to 50 per cent of the bitumen recovery by CSS. It stated that the physical model studies conducted by Batycky *et al.*[4] and Frauenfeld *et al.*[5] showed that solution gas contributed up to 50 per cent of the bitumen recovery, while the simulation study done by Denbina *et al.*[6] indicated that solution gas contributed over 20 per cent of the bitumen recovery.

With respect to reservoir simulation, CNRL stated that properly calibrated simulations suggested there was a 20 to 45 per cent negative impact on bitumen recovery by removing the solution gas. CNRL submitted a model study that predicted that degassing the bitumen resulted in a 23 per cent (or 4.2 percentile) reduction in bitumen recovery. CNRL's model was history-matched to the bitumen production data from one of its HWCSS wells at Primrose. However, CNRL did not model gas cap depletion in its simulation. It stated that simulating both gas cap depletion and the CSS process in one model was not realistic because this would require a 3-D model with small grid blocks, which would result in a prohibitive amount of time to run the simulation. CNRL modelled the effect of gas cap depletion by using a GOR of 8 m^3/m^3 for the nondepleted case and a GOR of 1 m^3/m^3 for the depleted case. It submitted that the solution GOR was 1 m^3/m^3 at a reservoir pressure of 500 kPa. CNRL stated that a prediction with its model indicated that only one additional cycle could be conducted on the well that its model was based on before the cycle exceeded the economic steam-oil ratio (SOR) of greater than 8 m^3/m^3. The predicted bitumen recovery was 20 per cent lower for the depleted case when the same economic SOR cutoff was applied.

With respect to EnCana's generic models for CNRL's area, CNRL stated they were not ground-truthed to any field data. CNRL argued that the generic flank and edge models showed little

4 "A Mechanistic Model of Cyclic Steam Stimulation," J. Batycky, R. Leaute, and B. Dawe, *Society of Petroleum Engineers* 37550, 1997.

5 "Effect of an Initial Gas Content on Thermal EOR as Applied to Oil Sands," T. Frauenfeld, R. Ridley, and D. Nguyen, *Journal of Petroleum Technology*, March 1988, pages 333-338.

6 "Evaluation of Key Reservoir Drive Mechanisms in the Early Cycles of Steam Stimulation at Cold Lake," E. Denbina, T. Boberg, and M. Rotter, *SPE Reservoir Engineering*, May 1991, pages 207-211.

transmission of the pressure drop, caused by gas production, to the bitumen zone where the CSS well was located, and this was not consistent with its piezometer data.

With respect to EnCana's piezometer model for Husky's area, CNRL stated that the large grid block sizes used in the model were not capable of simulating the processes critical to determining whether gas production negatively affected bitumen recovery. The model was not ground-truthed to any thermal recovery data, and the model failed to match the piezometer data, particularly the slope of the pressure versus time data. Also, the high cumulative SORs predicted by the model of 12 and 16 for SAGD and HWCSS respectively were unrealistic compared to the actual field data for Cold Lake. CNRL further noted that CSS conducted in the lower grade McMurray bitumen had lower SORs than those predicted by EnCana's piezometer model.

For both the generic and piezometer models, CNRL stated that the production cycles were too short, which excluded a major portion of the oil production that would be provided by solution gas drive. CNRL reran one of EnCana's generic edge models and its piezometer model with extended production cycles and stated that these reruns demonstrated that there was an impact of gas production on CSS bitumen recovery. CNRL also stated that there was no economic SOR cutoff applied to terminate the simulations in any of EnCana's model runs. CNRL contended that this made an unfair comparison between the different cases. It argued that if an economic limit were not considered, similar bitumen recovery would be achieved by CSS regardless of whether the reservoir was depleted or not prior to CSS being conducted. CNRL concluded that any bitumen production from uneconomic cycles in the simulation should not be considered in the comparison.

CNRL stated that the 20 to 50 per cent reduction in bitumen recovery caused by removal of the solution gas would translate into a 100 per cent loss of the bitumen, since the reduction in recovery would render the resource uneconomic. This was because the bitumen that CNRL was trying to protect was at the edges of the currently developable resource in the Primrose area. Since this bitumen had only marginal economic potential, any significant loss of recovery would result in sterilization of the bitumen resource.

6.2 Views of Husky

Husky submitted that gas production and the resulting loss of dissolved gas from the bitumen caused harm or a significant risk of harm to thermal bitumen recovery because it eliminated the solution gas drive mechanism and increased the bitumen viscosity. Husky supported its view with reservoir modelling and by reference to field data and technical papers.

Husky used reservoir simulation to assess the effect of gas production on bitumen recovery by HWCSS and HSAGD. Husky stated that the pressure decline rate predicted by its model was consistent with its piezometer data when the simulated values were shifted in time to line up with the piezometer data. Husky acknowledged that its initial 2-D simulation runs did not include a maximum liquid constraint and, except for the last runs that it submitted, the material balance errors for its runs were too high. Husky stated that the last 2-D runs it submitted demonstrated that there was an impact of gas production on bitumen recovery for both HWCSS and HSAGD. For HWCSS, Husky's model predicted that at the end of the runs, the bitumen recovery for the depleted case (where the gas zone was depleted to about 200 kPa) was 5.6 per cent (or 1.0 percentile) less than the recovery for the nondepleted case. Husky acknowledged that the cycle lengths used in the model were not optimal, since there were long periods of time during the production cycles for which there was no bitumen production, particularly in the later cycles. For HSAGD, Husky's model predicted that at the ends of the runs the bitumen recoveries and cumulative SORs for the depleted and nondepleted cases were essentially the same. However, Husky argued that for the first 15 years the recovery for the nondepleted case was predicted to be higher than that for the depleted case and for the first 10 years the cumulative SOR for the nondepleted case was predicted to be lower than that for the depleted case. Husky argued that the higher recovery and lower cumulative SOR in the early part of the HSAGD process were very important to the economic viability of the experimental process.

More generally, Husky stated that it was not appropriate to compare the bitumen recoveries and cumulative SORs just at the ends of the runs. The intermediate bitumen production rates, recoveries, and thermal efficiencies also needed to be considered. Husky also stated that the operating strategy used in its models had not been optimized, so the model results did not show the total impact of solution gas depletion on bitumen recovery. Alternative operating strategies could be used, and this could affect the results of the simulations. Husky stated that in EnCana's rerun of Husky's model, the production cycles were too short, resulting in the effect of solution gas drive being masked.

Husky raised several concerns regarding EnCana's piezometer model study of Husky's Caribou area. Husky contended that EnCana's use of transmissibility barriers under most of the areal extents of the two gas pools in its model (for which Husky argued there was no geological basis) and EnCana's misapplication of the net-to-gross ratio to the permeability of the water sands below the gas zones effectively sealed the gas zones from the bitumen zone. This incorrectly limited the extent of the pressure drop propagated into the bitumen zone. Husky also contended that EnCana's model provided a poor history match of the pressure data. Husky noted that EnCana did not model HSAGD; instead, it modelled only SAGD. Husky argued that it was not accurate to model the SAGD and HWCSS processes separately, considering the interaction and coupling of the two processes in HSAGD. Similar to CNRL's criticism of EnCana's piezometer model, Husky stated that the grid block sizes used in the thermal area were too large and consequently the model could not properly simulate the thermal recovery processes.

Husky submitted that EnCana's simulations did not result in any dilation effects, which negated the impact of recompaction. Since the CSS process in Cold Lake required steam injection above fracture pressure, Husky contended that EnCana's models did not model the CSS process properly and hence its runs were invalid. Husky noted EnCana's statement that the formation of free gas in the bitumen as a result of gas production should decrease the maximum achievable bottomhole injection pressure at a given steam injection rate. While Husky questioned the validity of EnCana's simulations, it argued that the statement by EnCana indicated that EnCana recognized that gas production adversely affected the HWCSS process.

Husky contended that CSS was one of the most difficult reservoir processes to model because of the complex multiphase geomechanical high-pressure and temperature physics involved. Husky argued that reservoir modelling was only one component of the evidence that supported its position. Husky stated that the geological data, its piezometer data and those of CNRL, the field data from Imperial and CNRL, and scientific papers clearly stated the importance of solution gas drive to CSS bitumen recovery.

Husky noted that there was no known practical way to turn dead bitumen into live bitumen, so any detrimental effect caused by degassing the bitumen could not be mitigated.

6.3 Views of Imperial

Imperial submitted that solution gas was a key recovery mechanism for CSS, so any removal of the dissolved solution gas would result in a reduction in bitumen recovery. Imperial based its views on its field experience and its physical and numerical models previously reported in the literature.

Imperial stated that its CSS field experience was with large partially depleted gas pools and that it did not have operating experience with large gas pools that were at either their discovery pressure or their abandonment pressure. Based on its field experience, Imperial expected the presence of a large partially depleted gas cap to reduce the recovery performance of CSS by 25 per cent.

Imperial reviewed the performance of CSS wells located adjacent to—but outside of—the zero edge of two of the gas pools on its Cold Lake oil sands lease. The CSS performance of these wells was compared to the performance of wells located one additional well spacing from the gas pools. Imperial did not observe any material changes in cumulative oil-steam ratio performance between the two groups of wells. Imperial considered this result to be reasonable, considering that it expected the fraction of solution gas removed from the associated bitumen as a result of the Clearwater gas production to be small. Of more significance was the water-steam ratio reduction observed at the wells adjacent to the gas pools, which indicated that the presence of the gas pool had influenced the performance of these wells.

Imperial stated that in light of the piezometer data submitted by CNRL and Husky, it believed that gas production was a concern for CSS wells adjacent to but outside the zero edge of a gas pool that had been partially or fully depleted. At the time of the hearing, Imperial noted that there were no definitive field data to prove, or disprove, this concern. This was due in part to none of the wells included in Imperial’s analysis having reached their economic limit. Consistent with its view that solution gas drive was a key recovery mechanism for CSS, Imperial stated that, on an intuitive level, any removal of the dissolved solution gas would result in a reduction in bitumen recovery. Since it had been demonstrated that degassing was occurring within the bitumen column directly under the gas caps, Imperial suggested it was logical to believe that degassing would extend laterally in the bitumen column beyond the zero edge of the gas caps. Imperial stated that its view that solution gas was a key recovery mechanism for CSS was based on physical models and mechanistic studies. Imperial cited the paper by Denbina *et al*., which estimated that solution gas drive provided about 20 per cent of the bitumen recovery over the first five cycles, as well as a subsequent Imperial study that showed that over 13 cycles the solution gas drive component of bitumen recovery remained at 20 to 30 per cent.

Imperial stated that it had operated CSS using both vertical (deviated) and horizontal wells at Cold Lake. Both well types had been used where gas caps had—and had not—been present. Imperial stated that it had noted no material differences in performance related to well type.

Imperial stated that it had produced gas from four Clearwater gas pools in the past, and following an internal review of potential risks, it had shut in all the gas wells. Imperial also stated that if it were to find a medium-sized gas pool on its Cold Lake oil sands lease, it would not produce the gas. Imperial stated that its decision to shut in the four gas pools was not based on reservoir simulation, but was an engineering judgement made by taking into consideration that the gas could always be turned back on, but the solution gas could not be put back into the bitumen. Imperial's decision to shut in the gas was a direct result of it seeing a 5 to 10 m column of "foamy oil" in a couple of its delineation wells. This demonstrated to Imperial that the pressure in the bitumen column had been reduced as a result of gas pool production. Imperial's decision to shut in the gas was associated with the performance of CSS directly under a gas cap; Imperial did not consider the potential for degassing of the bitumen away from the zero edge of the gas cap.

Imperial stated that although modelling of CSS was helpful, it was a computational challenge to include all the important reservoir mechanisms and to have appropriately gridded multiwell models for well interactions.

Imperial noted that the concern about the effect of gas production on bitumen recovery was much clearer in the case of SAGD than in the case of CSS. In SAGD the plan was to have sufficient pressure in the gas cap so the steam chamber pressure could be balanced against the gas cap pressure. The concern about the effect of gas production on bitumen recovery by CSS was more difficult to grasp. Since CSS involved cycling between high and low pressures, it was not possible to balance the pressure against the gas cap pressure. The concern was that gas production was potentially removing a recovery mechanism from CSS, but the effect was difficult to quantify. In Imperial's view, at some point if enough of the solution gas were removed from the bitumen, some of the bitumen resource would be lost.

6.4 Views of EnCana

EnCana contended that all the modelling evidence submitted to the hearing, including that of CNRL and Husky, indicated that gas production would not have a significant impact on bitumen recovery in the CNRL and Husky areas.

As mentioned earlier in this section, EnCana's generic models for CNRL's area included three different reservoir configurations:

- a nonedge model with and without a shale barrier between the gas and bitumen zones in which the HWCSS well was located directly underneath the gas zone;
- a flank model with and without a shale barrier between the gas and bitumen zones in which the closest lateral distance of the HWCSS well from the edge of the gas zone was 10 m; and
- an edge model without a shale barrier between the gas and bitumen zones in which the closest lateral distance of the HWCSS well from the edge of the gas zone was 650 m.

EnCana submitted the results for about 60 different runs that provided sensitivities to different parameters, such as the thicknesses and permeabilities of the gas and bitumen zones, the initial solution GOR, the pressure of the gas zone before CSS, the permeability multiplier factors for reservoir dilation, and the steam injection rates. Subsequent to its initial submission, EnCana indicated that 20 of the 26 nonedge runs, 13 of the 30 flank runs, and 4 of the 6 edge runs had material balance errors greater than 1 per cent. EnCana submitted reruns for 8 of the 13 flank runs using tight convergence control to reduce the material balance error to less than 1 per cent.

The reruns indicated that there was not much difference in the predicted recoveries and cumulative SORs at the ends of the runs compared to the initial runs.

EnCana stated that its generic models indicated that the bitumen recovery factors for HWCSS were essentially the same for the depleted/partially depleted (gas zone pressures of about 200 and 1000 kPa respectively) and nondepleted cases. EnCana contended that the flank model was the most relevant model for this hearing. For the flank models, the biggest difference in bitumen recovery factors between the depleted and nondepleted cases was 3.8 percentiles (or 10.0 per cent), with the depleted case actually having a higher recovery factor than the nondepleted case. However, the depleted case was one of the cases that had a material balance error greater than 1 per cent and was not rerun by EnCana.

EnCana acknowledged that its generic models had limitations and could not be used to predict absolute bitumen recovery with precision because there was no history match. However, EnCana argued that the models could be used for comparing the impact of gas production on bitumen recovery over a range of possible reservoir configurations. With respect to CNRL's criticism that the reservoir properties included in the models implied a diffusivity[7] that was much lower than that indicated by CNRL's piezometer data, EnCana argued that some of the cases it ran resulted in the pressures in the bitumen zone being lower than what the piezometer data showed, and those cases also showed that gas production did not affect HWCSS bitumen recovery. With respect to CNRL's criticism that EnCana's production cycles were too short and thereby minimized the contribution of solution gas drive, for its edge model EnCana provided a comparison of the predicted performance using its production schedule and that used by CNRL. The comparison indicated that over a 15-year period, the bitumen recovery obtained using EnCana's production schedule was about 2.4 times that obtained using CNRL's production schedule. However, the material balance errors for both runs were greater than 1 per cent.

EnCana also used its flank model to assess the effect of gas zone depletion on vertical well CSS. The model predicted a reduction in bitumen recovery of 4.4 percentiles (or 15.8 per cent) due to gas zone depletion. However, the depleted case had a material balance error greater than 1 per cent and was not rerun by EnCana. EnCana suggested that the reason why its model predicted gas zone production had a negative effect on vertical well CSS but not on horizontal well CSS was that gravity drainage was likely the more dominant performance driver for the depleted horizontal well case. EnCana did not believe that the analysis submitted by Imperial of its field data was adequate to allow it to conclude that there was no material difference in CSS performance related to well type.

EnCana submitted a revised flank model that was intended to model high-pressure HWCSS for gas flanking bitumen. EnCana acknowledged that its initial revised model did not achieve dilation of the reservoir but stated that a subsequent second revised model did. Although the input/output files for the second revised model were not part of the record for the hearing, a graph submitted by EnCana indicated that dilation was still not achieved for most of the cycles.

With respect to its second model study, the piezometer model for Husky's area, EnCana calibrated the model to the pressure data for the gas and bitumen zones. EnCana acknowledged that the predicted pressures in the bitumen zone in the northern part of the model area were lower than the field data and the predicted pressures in the southern part of the model area were higher

[7] Diffusivity is equal to the permeability divided by the product of the porosity, viscosity, and compressibility.

than the field data. However, EnCana contended that the quality of the history match was sufficient to ensure that the model had a more accurate representation of the geology in the area than could be provided by a generic model or by geological evaluations alone. EnCana assessed the impact of gas production on bitumen recovery by SAGD and HWCSS by running the model with continued gas production for the depleted case and with gas production shut in at the beginning of 2007 for the nondepleted case. The model predicted no difference in bitumen recovery between the depleted and nondepleted cases for either SAGD or HWCSS. EnCana acknowledged that the predicted bitumen recoveries of 23.5 and 12.0 per cent for SAGD and HWCSS respectively were lower than expected and the producing water cuts were higher than reported in CNRL's CSS operations. However, EnCana contended that while the bitumen recoveries could be increased and the SORs decreased by making changes to the model, it was unlikely that any of the changes would affect the conclusion about the effect of gas production on bitumen recovery. EnCana responded to Husky's criticism regarding the placement of permeability barriers at the base of the water zones by arguing that the barriers were local barriers and did not isolate the bitumen zone from the gas zones. EnCana contended that use of the barriers was justified to account for water being structurally above bitumen. EnCana acknowledged that the injection pressure in its piezometer model exceeded the dilation pressure only for a short time during the first cycle, after which the injection pressure was significantly below the dilation pressure. EnCana stated that due to solution gas liberation in the bitumen zone resulting from pressure reduction caused by gas production, the formation of free gas in the bitumen zone should decrease the maximum achievable bottomhole injection pressure at a given steam injection rate.

EnCana pointed out several limitations with CNRL's model, including the absence of a gas cap in the model, the assumption of almost dead oil at the beginning of the run for the depleted case, the short time of the runs—only nine years—and the lack of a prediction following the history match, and a substantial amount of the predicted loss of bitumen recovery due to gas production occurring in the early years, which involved low-pressure CSS. With respect to the last point, EnCana noted that high-pressure CSS was required for the Clearwater at Cold Lake. When EnCana reran CNRL's model using high-pressure instead of low-pressure CSS, the model predicted a difference in bitumen recovery of 2.2 percentiles (or 4.5 per cent) between the depleted and nondepleted cases. The predicted differences were less when GORs of 2, 3, and 5 were used instead of 1 m^3/m^3 for the depleted case. EnCana argued that this demonstrated that CNRL's own model predicted that degassing the bitumen would not have a significant impact on bitumen recovery for HWCSS.

With respect to Husky's model, EnCana stated that when it was run with acceptable material balance errors and realistic operating schedules and constraints, it showed that gas cap depletion would have no adverse impact on bitumen recovery by HSAGD and HWCSS. EnCana's rerun of Husky's HSAGD model predicted essentially the same recoveries at the ends of the runs for the nondepleted and depleted cases, while its rerun of Husky's HWCSS model predicted that the recovery for the depleted case was 0.4 percentiles (or 1.2 per cent) less than the recovery for the nondepleted case. In EnCana's rerun of Husky's HWCSS model, the gas well was inadvertently produced. When EnCana reran the model again with the gas well shut in, the difference in recovery increased to 0.7 percentile (or 2.1 per cent), although the input/output files for this rerun were not part of the record for the hearing. EnCana pointed out that the ratio of the original gas in-place to the original bitumen in-place in Husky's model was unreasonably high, at 475, compared to EnCana's estimate of 4.7.

EnCana argued that in the absence of applicable field experience, reservoir modelling was the best tool available to evaluate the effect of gas production on bitumen recovery. EnCana noted that Imperial's advice was that there were no definitive field data addressing the impact that depleting a gas pool would have on ultimate bitumen recovery by CSS in areas offsetting the gas pool. EnCana also argued against relying on the conclusions of technical papers since the authors were not available to be questioned. EnCana contended that the laboratory experiment conducted by Batcyky *et al*. was for a very small test that was not representative of the Clearwater reservoir in the CNRL and Husky lease areas. EnCana also argued that the modelling study done by Denbina *et al*. matched only the oil and water production, but not the gas production. Also, in estimating the effect of solution gas drive by disabling it, the study assumed dead bitumen.

To try to explain why its models showed no impact on bitumen recovery even though some solution gas was migrating from the bitumen to the gas caps, EnCana suggested that solution gas drive may not be a significant drive mechanism for HWCSS and HSAGD in the CNRL and Husky areas or that the solution gas was of some importance but there were other drive mechanisms, such as gravity drainage, that compensated for the solution gas drive mechanism.

6.5 Views of the Board

The Board notes that reservoir modelling was the focus of much of the work done to assess the potential impact of gas production on thermal bitumen recovery and constituted most of the evidence. As expected when modelling a complex situation without a clear thermal operational history to calibrate the models, considerable care must be taken to understand the process being modelled and the models themselves. In this case, the Board believes there are significant limitations with all the model studies submitted to the hearing.

Although CNRL's model study was the only study that matched available thermal field data, it was only for a single well, so the model could not account for any well interactions that could occur during multiwell CSS operations. Also, the study did not include a gas zone to simulate the depletion of gas from the bitumen zone. Husky's model did not match any thermal data, and although the pressure decline rate predicted by Husky's model was consistent with the field data when the simulated values were shifted in time, Husky did not do an actual history match of the pressure data. Also, Husky acknowledged that the operating strategy used in its model was not optimized.

Although EnCana's generic model study evaluated many different cases to test sensitivities to several different parameters, the models were not matched to any field pressure or thermal data. Also, the models do not appear to have simulated high-pressure HWCSS properly, because they did not effectively dilate the reservoir. Although EnCana undertook a history match of the pressure data with its piezometer model, some of the data were not matched very well and no thermal field data were matched. The high cumulative SORs predicted by the model for both SAGD and HWCSS raise a question about the ability of the model to adequately predict the performance of thermal recovery. Also, the HWCSS model did not effectively dilate the reservoir. For both the generic and piezometer models, EnCana compared the bitumen recoveries and cumulative SORs for the depleted and nondepleted cases at the ends of the runs; no economic cutoff, such as an SOR, was considered in comparing the depleted and nondepleted cases.

The Board agrees with Husky and Imperial that the CSS process is difficult to model because it is a complex process and including all the important reservoir mechanisms is a challenge. The Board also agrees with CNRL that it is difficult to realistically model both the CSS process and the effect of gas zone depletion. Because of the significant limitations of all the model studies, the Board is not convinced that they can be relied upon to determine the fundamental question of whether solution gas is an important recovery mechanism for CSS. The Board views the use of modelling to evaluate the importance of solution gas drive to CSS bitumen recovery to be a more difficult task than the use of modelling to evaluate the effect of a thief zone on SAGD bitumen recovery, as was done in the Athabasca hearings.

In the absence of convincing model studies, the Board must refer back to the basics of resource conservation. The technical literature over several years has reported an industry view that solution gas drive is an important drive mechanism for bitumen recovery by CSS. While the Board acknowledges that there are limitations in using the conclusions from technical papers, the Board believes they provide the current understanding of the issue. The Board also notes the view expressed by Imperial, which, as the most experienced operator with CSS, has concluded that solution gas drive is a key drive mechanism for CSS. Based on its technical judgement and understanding, the Board concludes that solution gas drive is an important drive mechanism for bitumen recovery by CSS.

Considering that all the parties agree that gas production has caused pressure depletion in the bitumen zone and this in turn has caused solution gas to evolve from the bitumen and migrate to the gas zones, the Board concludes that this gas production presents a risk to CSS bitumen recovery by reducing the solution gas drive mechanism. As stated above, the Board believes that the solution gas drive mechanism is important, so its reduction could result in an unacceptable detrimental effect on CSS bitumen recovery. In the case of marginal bitumen reserves, such as those that CNRL has requested be protected, the Board accepts CNRL’s view that reduction of the solution gas drive could result in the sterilization of the reserves. The Board agrees with Husky and Imperial that there is no practical way to turn dead bitumen into live bitumen to try to mitigate any detrimental effects that could be caused by removing the solution gas. For these reasons, the Board concludes that gas production that is causing the evolution and migration of solution gas presents an unacceptable risk to CSS bitumen recovery and, consistent with its conservation mandate, believes that gas production controls are necessary. The nature and extent of these controls is dependent on the extents of the regions of influence, which are discussed in Section 8.

7 FEASABILITY OF COLD AND THERMALLY INDUCED BITUMEN RECOVERY

In addition to CSS and HSAGD, two other bitumen recovery methods were considered at the hearing: primary cold production and thermally induced production.

7.1 Cold Production

7.1.1 Views of CNRL

CNRL submitted that primary production potential existed in the upper portions of the Primrose East Yellow Valley sand directly east of the Moore A, B, and C gas pools in and around section

4-68-3W4M. It stated that bitumen viscosity increased vertically with lower viscosity bitumen of less than 50 000 millipascal second (mPa.s) occupying the upper 5 m of the Primrose East reservoir. CNRL stated that a primary pilot conducted at Primrose East Burnt Lake in the early 1990s had bitumen production rates of 10 to 30 m^3/d/well. CNRL submitted data that showed cumulative bitumen production from the pilot ranged from about 1650 to 14 370 m^3/well, which resulted in a range of bitumen recoveries from 1 to 9 per cent when the full thickness of the bitumen pay was used. However, CNRL noted bitumen recoveries ranged from 3.2 to 36.4 per cent when it assumed that only the top 6 m of bitumen pay was contributing to production because of the lower viscosity at the top of the zone. It stated that the use of current technology in primary production would increase the production efficiency of the Clearwater due to improvements in sand handling and well stimulations through the use of coiled tubing. CNRL indicated that the top 5 to 8 m in the pilot area would have primary potential and concluded that a 6 m zone in the potential primary area with a bitumen viscosity of 35 000 mPa.s would do quite well.

7.1.2 Views of EnCana

EnCana argued that based on the Burnt Lake Pilot, CNRL would have to drill about 125 wells and would recover only about 2500 m^3/well. Therefore, it concluded that primary cold flow in this area was not an economic proposition. It stated that actual results from the Burnt Lake Pilot showed that on an average per-well calendar-day basis, 60 per cent of the producing months had bitumen production rates less than 10 m^3/d. EnCana stated that the net bitumen pay in the area of the Burnt Lake Pilot was 20 m, while it was less than 7 m in CNRL's primary area. EnCana also pointed out that CNRL had not followed up on the Burnt Lake Pilot with a commercial project, as it would have if the pilot had been successful.

7.1.3 Views of the Board

The Board agrees with CNRL that there is long-term potential for primary production in and around section 4-68-3W4M. The Board notes that data from the Burnt Lake Pilot show that some of the wells were capable of producing significant volumes of bitumen. The Board accepts that the use of current technology in primary production could increase the production efficiency of the Clearwater beyond that demonstrated in the Burnt Lake Pilot.

7.2 Thermally Induced Production

7.2.1 Views of CNRL

CNRL stated that thermally induced flow potential existed in the E facies along the western edge of the Fisher Clearwater E Pool after the E facies had been heated by CSS operations in the underlying A and B facies. It estimated that CSS operations in the A and B facies, with an average temperature of about 150^{o}C for 10 to 15 years, would cause conductive heating of the overlying C, D, and E facies to temperatures in the range of 80 to 120^{o}C. The elevated temperatures would decrease bitumen viscosity to below 1000 mPa.s, rendering the bitumen exploitable by cold production.

CNRL used heating of bitumen in the General Petroleum Formation (GP) that overlies the North Tangleflags thermal project in Saskatchewan to show how conductive heating assisted in bitumen recovery. It stated that the comparison between the GP in North Tangleflags and the

Clearwater in Primrose was intended to be only on the basis of the conductivity of the lithology to deliver heat from the horizon of steam injection to any smaller volumes of bitumen above. CNRL stated that a surface temperature of 40°C was measured for the bitumen produced from the GP in the14/15-23-52-25W3M well 10 years after thermal operations commenced in the underlying Lloydminster Formation 20 m below. CNRL stated that this temperature could be matched by calculation using the thermal diffusivity empirically derived from Cold Lake operations and that a similar calculation showed that the temperature could be expected to increase with time. CNRL indicated that before the bitumen in the GP was conductively heated, attempts at primary production failed due to high initial viscosity, but recent attempts to produce the bitumen had been successful. CNRL stated that it would not undertake cold production in the Clearwater in Primrose until major bitumen units were first produced, thereby maximizing the time for conductive heating to occur.

CNRL stated that its operational experience with CSS in the A and B facies indicated that even at the end of the steaming cycle, when the temperature was under 100°C, the A and B facies produced at a 50/50 oil cut. Since the A and B facies had similar oil and water saturations as the E facies, the 2 to 3 m of bitumen pay in the E facies should be producible with the existing infrastructure in the area when the bitumen viscosity was reduced by conductive heating.

7.2.2 Views of EnCana

EnCana argued that there was no evidence to demonstrate that production from the E facies at Cold Lake was possible through any means, including thermally induced cold flow. The thinness of the zone and the low quality of the reservoir in the E facies made bitumen production an unrealistic expectation. EnCana stated the North Tangleflags area was not analogous to the Clearwater in Cold Lake, since the sands at Tangleflags were of high quality, with a water saturation of only 17 per cent, whereas the E facies in the Cold Lake Area was of much poorer quality, with a water saturation of 41 per cent. EnCana also indicated that in 2006 the Tangleflags GP pool had 11 producing oil wells, only 2 of which overlay the Lloydminster thermal area.

7.2.3 Views of the Board

The Board agrees with CNRL that temperature data from North Tangleflags indicates that heating of the A and B facies in the Cold Lake area has the potential to heat the smaller volume of bitumen in the overlying E facies. The Board agrees with EnCana that the quality of the reservoir in the GP in the Tangleflags area is better than the quality of the reservoir in the E facies the Cold Lake area. However, the Board notes that CNRL stated that it had success in producing the A and B facies, which have similar quality to the E facies, at the end of the steaming cycles, when the temperatures were under 100°C. The Board believes that heating of the E facies from the underlying A and B facies should provide reasonably good potential to make the bitumen in the E facies producible.

8 REGION OF INFLUENCE

In *Interim Directive (ID) 99-1*,[8] the Board defines "region of influence" (ROI) as "the extent of the gas pool in the case of gas directly overlying bitumen or the combined extent of the gas pool and the water zone in the case of gas overlying water overlying bitumen." This definition is based on the premise that there is no significant pressure transmission through the bitumen zone. In this hearing, evidence was provided regarding the transmission of pressure through the Clearwater bitumen zone and consequently the need to revise the definition of the ROI for the Clearwater.

8.1 Views of CNRL

CNRL discussed pressure data from 15 piezometers that it had installed in eight wells on its oil sands lease. These piezometers had been measuring pressures since early 2000 to early 2002. Of these 15 piezometers, 8 were installed in five of the wells located about 200 to 700 m from the edges of the gas caps or associated water zones, according to CNRL's mapping of the gas and water zones. However, CNRL indicated that the gas pools were basically migrating across the top of the reservoir because of the evolution and migration of solution gas, and therefore it could not accurately determine the distances of the piezometer wells to the edges of the gas caps. It also stated that it had extended its mapped gas pool contours as far as it could to maximize the volumetric gas in-place. The data from these 8 piezometers showed pressures drops ranging from about 300 to about 1600 kPa.

CNRL stated that pressure data collected from all of its piezometers showed significant pressure depletion in the Clearwater bitumen zone due to production from gas pools in the Clearwater. It indicated that this pressure decline in the bitumen zone occurred in only months in some cases and maintained that the magnitude of the pressure decline would increase with time. CNRL indicated that the pressures in the bitumen zones had been measured to be lower than 1000 kPa. This was illustrated by the pressure of 933 kPa measured in the bitumen zone in August 2006 in the piezometer in well 11-12-68-4W4M (11-12) and the pressure of about 900 kPa measured in the bitumen zone in June 2006 in the piezometer in well 13-33-67-3W4M (13-33). CNRL's gas pay mapping indicated that the 11-12 well was at the edge of a gas pool and that the 13-33 well was about 600 m from the edge of a gas pool.

CNRL stated that the ROI could be calculated from the hydraulic diffusivity equation. CNRL determined the hydraulic diffusivity of the Clearwater in the Primrose area by using pressure response data from a 1992 pilot of Combined Drive Drainage. It noted that pressure responses measured by piezometers resulting from steam injection into the Orange and Blue sands occurred within days in both sands. It stated that similar rates of change in pressure were measured by the piezometers in both the Orange and Blue sands, suggesting that the sands had similar diffusivities. Simulation of the pressure response in the two sands yielded a good match with the measured pressure data using a diffusivity of .0015 square metres per second ($1.5\ 10^{-3}\ m^2/s$). CNRL performed calculations to predict the pressure drops measured by the piezometers in the 9-16-67-5W4M well that were caused by depletion of the Fisher Clearwater A Pool. The diffusivity of $1.5\ 10^{-3}\ m^2/s$ gave the best match of the pressure data, when the distance from the gas pool edge to the piezometers was assumed to be 600 m. In contrast, lower diffusivities such

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

as those calculated from EnCana's simulations required unreasonably close proximity of the piezometers to the gas pool edge. CNRL stated that the diffusivity of 1.5 10^{-3} m^2/s was slightly higher than the diffusivity reported in the literature due to the Primrose reservoir having somewhat higher water saturation.

CNRL calculated an ROI using a single-phase model with a diffusivity of 1.5 10^{-3} m^2/s and assuming that the water was a continuous mobile wetting phase. CNRL started with a gas cap pressure of 3000 kPa and over a period of 5 years reduced the pressure to 500 kPa. It calculated the pressure drops at different distances away from the edge of the gas cap over a period of 20 years from the start of the pressure decline. CNRL defined the outer boundary of the ROI as the distance from the edge of the gas cap where a pressure drop of 100 kPa was calculated after 10 years. It stated that although this was an arbitrary cutoff, it was in reasonable field units and time scale and thus was measurable. When a very large gas cap radius was used to approximate a linear system, the 100 kPa pressure drop after 10 years was calculated to occur at a distance of 2 kilometres (km) from the edge of the gas cap. This distance was calculated to be 1.7 km when a gas cap radius of 1600 m was used to approximate the gas production area for the Fisher Clearwater A Pool, and it was calculated to be 1.8 km when a 4000 m gas cap radius was used to approximate the gas production area of the Fisher Clearwater E/F and Moore Clearwater B/C pools. Based on its calculations, CNRL used 2 km from the edge of the gas caps as its ROI.

CNRL pointed out that its calculations assumed communication through a mobile water phase, but a mobile gas phase would eventually provide a much higher diffusivity and a larger ROI. It stated that a mobile gas phase had been implied by all parties, since they had all assumed that the gas caps were producing solution gas.

8.2 Views of Husky

Husky submitted pressure data from 31 piezometers installed in seven wells on its oil sands lease. Of these 31 piezometers, 14 were in three wells located about 700 to 2200 m away from the edges of the gas caps or associated water zones, according to Husky's mapping of the gas and water zones. The range of pressure drops indicated by these piezometers was from no pressure drop to about 460 kPa.

Husky stated that its peizometers had been providing continuous pressure data since March 2006 and showed a pervasive declining pressure trend in the bitumen. It stated that the only source of pressure depletion was EnCana's gas production. Husky claimed that the piezometer data both above and below the C/D mudstone confirmed that there was a pressure drop across the C/D mudstone due to gas production. Husky provided two typical decline trends for the last few months from its piezometer data, which showed average declines of 3.7 and 6.5 kPa/month. Husky indicated that using these declines would result in the pressure in the bitumen zone being depleted from 2800 to 500 kPa in 52 and 32 years respectively. Husky stated that pressure drops had been measured in piezometers in the bitumen zone over 3 km away from the edge of the gas caps. It added that this pressure decline was moving through the bitumen zone and would continue to move throughout the entire bitumen reservoir in response to a decrease in the pressure of the gas caps. Husky indicated that it based its 3 km ROI on the pressure drops and declining pressure trends in the piezometers in the 4-6-69-4W4M well.

8.3 Views of EnCana

EnCana stated that there was no evidentiary basis to expand the ROI defined in *ID 99-1*, since its evidence clearly demonstrated that the recovery of flank bitumen would not be affected by gas cap depletion. EnCana submitted that if the Board determined that a certain amount of pressure depletion did equate to damage to bitumen recovery, the Board would have to define the amount of pressure depletion that would cause this damage and determine the ROI as the distance from the gas caps where that pressure depletion occurred. EnCana stated that all of the wells in a producing pool and the areal extent of the top water should be included in the ROI.

With respect to CNRL's piezometer data, EnCana stated that there was only one piezometer for which it trusted the pressure data. EnCana indicated that the pressures recorded by the piezometer in the 02/9-29-67-3W4M (02/9-29) well were completely normal, with the initial pressure being lower than the virgin pressure and then declining to basically follow the trend of pressure depletion in the gas wells. EnCana interpreted a pressure drop of about 805 kPa in the 02/9-29 piezometer well, which it stated was about 550 m from the edge of a gas cap. EnCana identified the following concerns with some of the other piezometer data:

- The pressures measured by the piezometer in the 13-10-68-3W4M (13-10) well were initially down in the range of the gas zone pressure, but then increased suddenly and trended slowly up to about the same pressure as that in the 02/9-29 well.
- The pressures measured by the piezometer in the 13-33-68-4W4M well were much different from those recorded by the piezometers in the 02/9-29 and 13-10 wells, despite all three piezometer wells being about the same distance from the gas pools.
- The piezometer in the 11-12 well was in a bitumen zone 220 m from the gas zone and the piezometer appeared to be reading consistently low because the pressure was lower than the pressure in the gas cap.

With respect to Husky's piezometers, EnCana stated that the stabilization period was anywhere from weeks to three or four months. EnCana believed that the trends in the pressure declines shown by the piezometers after that time were valid. It agreed that the majority of the piezometer pressures were declining continuously and that there was solution gas evolving from the bitumen and migrating into the gas cap. However, EnCana stated that the vast majority of the piezometer pressure data showed very little pressure decline in the bitumen zone, with an average pressure drop of about 200 kPa after 14 years of production.

8.4 Views of the Board

The Board notes that the definition of the ROI in *ID 99-1* was based on the premise that there is no significant pressure transmission through the bitumen zone. The Board believes that the piezometer data provided at this hearing indicates that a revised definition of the ROI is needed for the Clearwater to account for the transmission of pressure through the bitumen zone.

In *Decision 2000-22*,[9] the Board discussed the difficulty of determining a proper definition of the ROI. The Board stated that the transmission of pressure changes depends on fluid and rock properties (i.e., compressibility, viscosity, permeability, and porosity) and their distributions, on

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

the distance from the production wells, and on time. However, the Board recognized that collecting data at the resolution needed for a precise definition of an ROI is impractical and economically prohibitive. The Board concluded that the definition in *ID 99-1* provided for the minimum size of an ROI.

Although a considerable amount of piezometer data was provided at the hearing, the Board does not believe the data were sufficient to permit a precise determination of what the ROI should be. Nevertheless, extrapolation of the available pressure data and CNRL's calculations over a long period of time indicate to the Board that continued gas production could result in a significant pressure drop in the bitumen zone over distances of a few kilometres beyond the edges of the gas and associated water zones. Accordingly, the Board will adopt an ROI of 2 km beyond the edges of the gas and associated water zones. As more data are gathered and analyzed, there may be a need to change this value.

9 DISPOSITION OF THE APPLICATIONS

As stated in Section 6, there was general agreement among the parties that gas production from the gas zones had caused pressure depletion in the bitumen zone, which in turn had caused solution gas to evolve from the bitumen and migrate to the gas zones. In Section 6.5 the Board concluded that solution gas is an important drive mechanism for bitumen recovery by CSS, and in Sections 7.1.3 and 7.2.3 it concluded that primary cold production and thermally induced production of bitumen are feasible in parts of CNRL's oil sands lease. Accordingly, the Board has assessed whether the gas pools involved in the applications considered at this hearing are in pressure communication with potentially recoverable bitumen and determined that if they are, the gas pools will not be allowed to produce. The determination of pressure communication was based on using an ROI of 2 km beyond the edges of the gas pools and the associated water zones, as established in Section 8.4. Thermal potentially recoverable bitumen was based on a thickness cutoff of 7 m of net bitumen pay, as discussed in Section 5.4.4. Potentially recoverable bitumen using cold primary production and thermally induced production was based on the areas identified in Section 7. The assessment of whether gas pools should not be allowed to produce was primarily made using Figure 7, a map of the area of application showing the Board's interpretation of the gas pools and the associated water zones, the net bitumen pay above the continuous shales and mudstones, and the 2 km extended ROI. Table 1 lists the wells and intervals that are designated to each of the pools discussed below.

9.1 Application No. 1394112

The Board finds that the Clearwater gas in the 14-31-68-4W4M well is in a pool that directly overlies 10 m or more of net bitumen pay and therefore denies EnCana's application to produce Clearwater gas from this well.

9.2 Application No. 1409180

CNRL's application is to shut in intervals in 18 wells contained in four Clearwater gas pools: the Fisher Clearwater A, E, PP, and Moore Clearwater B Pools, as designated by the Board in this decision (Figure 7). The Board's findings regarding these pools are as follows:

- The Fisher Clearwater A Pool extends over a small area that has 7 m or more of net bitumen pay. Its ROI extends over an area that has 10 m or more of net bitumen pay.
- The Fisher Clearwater E Pool's ROI extends over two areas that have 10 m or more of net bitumen pay, an area on the west side of the pool that has potential for thermally induced bitumen production, and a small area to the east of the pool in and around section 4-68-3W4M that has primary cold production potential.
- The Fisher Clearwater PP Pool underlies the regional shale. Its ROI extends over an area that has 10 m or more of net bitumen pay.
- The Moore Clearwater B Pool extends over a small area that has 7 m or more of net bitumen pay that is outside CNRL's oil sands lease. Its ROI extends over an area that has 10 m or more of net bitumen pay and over a small area to the east of the pool in and around section 4-68-3W4M that has primary cold production potential.

The Board finds that all of the intervals in the wells that CNRL has requested be shut in are in pools that are in pressure communication with potentially recoverable bitumen, and therefore the Board grants CNRL's application. Since the Board's practice is to shut in or not allow gas production on a pool basis, all intervals interpreted by the Board to be within the four pools involved in CNRL's application are included in the shut-in or not-allowed-to-produce list in Table 1, including intervals not requested to be shut in by CNRL. The Board notes that CNRL and EnCana agreed that if gas is shut in, it should be shut in on a pool basis.

9.3 Application No. 1481725

Husky's application is to shut in intervals in 24 wells and to not allow production from intervals in 13 wells that are contained in eleven Clearwater gas pools: the Fisher Clearwater B, E, G, S, T, CC, DD, EE, TT, U/D 052 (8-26-69-5W4M), and U/D 006 (11-13-70-5W4) Pools (Figure 7). The Board's findings regarding these pools are as follows:

- The Fisher Clearwater B Pool extends over a small area of Husky's oil sands lease and over a large area outside Husky's oil sands lease that have 10 m or more of net bitumen pay. Its ROI extends over large areas inside and outside Husky's oil sands lease that have 10 m or more of net bitumen pay.
- The Fisher Clearwater E Pool, as discussed in Section 9.2, has an ROI that extends over two areas that have 10 m or more of net bitumen pay. Of these areas, the one to the northwest of the pool extends over Husky's oil sands lease.
- The Fisher Clearwater G Pool touches the edge of the 7 m net bitumen pay contour and its ROI extends over an area that has 10 m or more of net bitumen pay.
- The Fisher Clearwater S Pool is within the ROI of the B Pool, and it directly overlies an area outside Husky's oil sands lease that has 10 m or more of net bitumen pay.
- The Fisher Clearwater T Pool is within the ROI of the G pool and is thereby connected to net bitumen pay of 10 m or more.
- The Fisher Clearwater CC pool's ROI overlies an area that has 7 m or more of net bitumen pay.
- The Fisher Clearwater DD Pool is under the regional shale and does not have 7 m or more of net bitumen pay within its ROI.

- The Fisher Clearwater EE Pool is under the regional shale and does not have 7 m or more of net bitumen pay within its ROI.
- The Fisher Clearwater TT Pool's ROI overlies an area that has 7 m or more of net bitumen pay that is outside Husky's oil sands lease.
- The Fisher Clearwater U/D 052 Pool (well 8-26-69-5W4M) is connected through a water zone to the B pool, and it also directly overlies an area just outside Husky's oil sands lease that has 10 m or more of net bitumen pay. Its ROI overlies an area in Husky's oil sands lease that has 10 m or more of net bitumen pay.
- The Fisher Clearwater U/D 006 Pool (well 11-13-70-5W4M; interval 442.5-445 m KB) is separated by shale from the overlying Fisher Clearwater B Pool and also latterly by shale from the thick bitumen to the west and therefore is not in pressure communication with potentially recoverable bitumen.

With the exception of the Fisher Clearwater DD, EE, and Undefined (well 11-13-70-5W4M) Pools, the Board finds that all of the intervals in the wells that Husky requested be shut in or not be allowed to produce are in pools that are in pressure communication with potentially recoverable bitumen. Therefore, the Board grants Husky's application except for the intervals in the three pools. Similar to what was said about the pools involved in CNRL's application, since the Board's practice is to shut in or not allow gas production on a pool basis, all intervals interpreted by the Board to be within the eight pools that the Board is not allowing production from that are involved in Husky's application are included in the shut-in or not-allowed-to-produce list in Table 1, including intervals not requested by Husky to be shut in or not to be allowed to produce. The Board notes that Husky and EnCana agreed that if gas is shut in, it should be shut in on a pool basis.

10 NEED FOR A BROADER BITUMEN CONSERVATION STRATEGY

As mentioned in Section 3, in *Bulletin 2006-14* the Board stated that it would hold two separate hearings on three applications it had received regarding gas production in the Cold Lake and Peace River OSAs and indicated that based on the findings of the hearings it would assess the need for a broader bitumen conservation strategy in the two OSAs. The hearing planned for the application in the Peace River OSA was not held because the application was withdrawn. Husky submitted to this hearing that a broader bitumen conservation strategy is necessary for the Clearwater. Since the Board has found it necessary to shut in gas as a result of this hearing, it believes there is a need to assess whether additional gas production should be curtailed in situations similar to those considered at this hearing. The specific process that should be used to conduct the assessment should be determined by the Board at a later time.

Dated in Calgary, Alberta, on July 24, 2007.

ALBERTA ENERGY AND UTILITIES BOARD

[Original signed by]

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

[Original signed by]

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

[Original signed by]

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

APPENDIX 1 HEARING PARTICIPANTS

Principals and Representatives (Abbreviations used in report)	Witnesses
Canadian Natural Resources Limited (CNRL) P. J. McGovern	J. Dudley, Ph.D., P.Eng. Q. Jiang, Ph.D., P.Eng. D. Payne, P.Eng. D. Youck, P.Eng.
Husky Oil Operations Limited (Husky) R. W. Block, Q.C. S. Anderson	G. Coskuner, Ph.D., P.Eng. C. Hanna, P.Geol. G. Mihaichuk, P.Eng. P. Collins, P.Eng., Consultant I. Gates, Ph.D., P.Eng., Consultant M. J. Ranger, Ph.D., P.Geol., Consultant
EnCana Oil & Gas Partnership (EnCana) D. G. Davies	K. Cole S. Obrigewitsch, P.Eng. K. Adegbesan, Ph.D., P.Eng., of Kade Technologies Inc. J. D. Macgowan. P.Eng., of J. D. Macgowan & Associates Ltd.
Imperial Oil Limited (Imperial) P. L. Miller	R. J. Babiy, P.Geol. G. Scott, P.Eng.
Alberta Energy and Utilities Board staff G. D. Perkins, Board Counsel K. Bieber, P.Geol. G. Dilay, P.Eng. N. Sitek, P.Geol. E. E. Smith, P.Eng. C. Evans, P. Geol.	

Table 1. List of Subject Wells

Field	Pool	Unique Well Identifier	Applicant	Company Top Perf. Depth (TVD)	Company Base Perf. Depth (TVD)	Board Pay Top Depth (TVD)	Board Pay Base Depth (TVD)	Licensee	Decision
Fisher	Clearwater A	AA/11-15-067-05W4				446.5	447.5	CNRL	not produce
		AA/01-22-067-05W4				451.0	452.5	CNRL	not produce
		00/10-22-067-05W4	CNRL	448.0	511.0	447.9	452.5	CNRL	shut in
	Clearwater B	00/15-16-069-04W4				458.0	458.4	EnCana Corporation	not produce
		00/06-17-069-04W4	Husky	445.0	447.0	444.9	447.8	EnCana Corporation	shut in
		AA/04-18-069-04W4				437.0	437.6	Husky Oil Operations Limited	not produce
		00/06-19-069-04W4	Husky	440.8	441.8	440.8	443.6	EnCana Corporation	shut in
		00/06-20-069-04W4				452.3	457.3	EnCana Corporation	not produce
		00/05-21-069-04W4	Husky	443.5	449.0	443.3	451.0	EnCana Corporation	shut in
		00/06-28-069-04W4	Husky	423.0	430.0	423.2	434.5	EnCana Oil & Gas Co. Ltd.	shut in
		00/05-29-069-04W4	Husky	435.4	438.0	435.0	443.0	EnCana Corporation	shut in
		00/14-30-069-04W4				437.6	446.2	EnCana Oil & Gas Co. Ltd.	not produce
		00/04-31-069-04W4				439.6	446.0	EnCana FCCL Oils Sands Ltd.	not produce
		00/07-31-069-04W4				435.7	446.0	EnCana FCCL Oils Sands Ltd.	not produce
		00/09-31-069-04W4				437.4	447.0	EnCana Oil & Gas Co. Ltd.	not produce
		02/09-31-069-04W4	Husky/np	435.3*	444.0**	435.3	444.0	EnCana Oil & Gas Co. Ltd.	not produce
		03/09-31-069-04W4				438.0	446.6	EnCana Oil & Gas Co. Ltd.	not produce
		00/06-32-069-04W4	Husky	430.0	434.0	430.0	441.3	EnCana Corporation	shut in
		02/06-32-069-04W4	Husky/np	425.5*	436.0**	425.5	436.0	EnCana Oil & Gas Co. Ltd.	not produce
		00/13-32-069-04W4	Husky/np	425.6*	437.0**	425.6	437.0	EnCana Oil & Gas Co. Ltd.	not produce
		05/13-32-069-04W4				431.4	443.0	EnCana Oil & Gas Co. Ltd.	not produce
		02/10-35-069-05W4	Husky	435.0	436.5	435.0	437.0	EnCana Corporation	shut in
		00/05-36-069-05W4				433.0	436.0	EnCana Oil & Gas Co. Ltd.	not produce
		00/08-36-069-05W4	Husky	441.0	444.0	441.3	442.6	EnCana Corporation	shut in
		00/16-13-070-05W4				430.2	430.4	EnCana Corporation	not produce
		00/12-04-070-04W4	Husky	427.8	428.3	427.8	429.5	EnCana FCCL Oils Sands Ltd.	shut in
		00/03-05-070-04W4				429.3	438.0	EnCana Oil & Gas Co. Ltd.	not produce
		00/04-05-070-04W4	Husky/np	429.3*	435.6**	429.3	435.6	EnCana Oil & Gas Co. Ltd.	not produce
		04/04-05-070-04W4	Husky/np	427.0*	432.0**	427.0	432.0	EnCana Corporation	not produce
		00/10-06-070-04W4	Husky	428.5	438.0	428.5	442.3	EnCana Corporation	shut in
		02/10-06-070-04W4	Husky/np	428.3*	442.0**	428.3	442.0	EnCana Corporation	not produce
		00/06-02-070-05W4				441.2	446.2	EnCana Corporation	not produce
		00/06-12-070-05W4	Husky	434.0	440.0	433.5	443.8	EnCana Corporation	shut in
		02/06-12-070-05W4	Husky/np	434.0*	443.4**	434.0	443.4	EnCana Corporation	not produce
		00/06-13-070-05W4				431.7	432.4	EnCana Oil & Gas Co. Ltd.	not produce
		00/11-13-070-05W4	Husky	442.5	445.0	423.0	424.0	EnCana Oil & Gas Co. Ltd.	shut in
		00/12-13-070-05W4				430.5	431.0	EnCana Oil & Gas Co. Ltd.	not produce

Table 1. List of Subject Wells

Field	Pool	Unique Well Identifier	Applicant	Company Top Perf. Depth (TVD)	Company Base Perf. Depth (TVD)	Board Pay Top Depth (TVD)	Board Pay Base Depth (TVD)	Licensee	Decision
Fisher (cont.)	Clearwater B (cont.)	00/14-13-070-05W4				424.0	424.5	EnCana FCCL Oils Sands Ltd.	not produce
		02/14-13-070-05W4				430.8	431.3	EnCana Oil & Gas Co. Ltd.	not produce
		00/05-14-070-05W4				425.0	429.8	EnCana Oil & Gas Co. Ltd.	not produce
		00/07-14-070-05W4				430.5	432.0	EnCana Corporation	not produce
		00/13-14-070-05W4				424.2	428.0	EnCana Oil & Gas Co. Ltd.	not produce
	Clearwater CC	00/13-27-068-05W4	Husky/np	461.5*	463.2**	461.5	463.2	EnCana Corporation	not produce
		00/16-28-068-05W4	Husky/np	452.7*	454.7**	452.7	454.7	EnCana Oil & Gas Co. Ltd.	not produce
		02/16-28-068-05W4	Husky	453.5	454.5	453.3	455.9	EnCana Oil & Gas Co. Ltd.	shut in
		00/11-33-068-05W4	Husky	450.5	452.0	450.5	453.2	EnCana Corporation	shut in
	Clearwater DD	00/13-27-068-05W4				473.0	474.8	EnCana Corporation	produce
		00/16-28-068-05W4				463.6	466.2	EnCana Oil & Gas Co. Ltd.	produce
		02/16-28-068-05W4	Husky	464.5	465.5	464.3	466.1	EnCana Oil & Gas Co. Ltd.	produce
		00/11-33-068-05W4	Husky	462.0	463.0	461.5	464.2	EnCana Corporation	produce
	Clearwater E	00/07-31-067-03W4	CNRL	435.0	437.0	435.1	441.5	EnCana Corporation	shut in
		02/07-31-067-03W4				433.2	438.4	EnCana Oil & Gas Co. Ltd.	not produce
		00/06-32-067-03W4	CNRL	434.5	438.0	434.5	439.0	EnCana Oil & Gas Co. Ltd.	shut in
		00/09-25-067-04W4				435.2	435.5	CNRL	not produce
		00/11-06-068-03W4	CNRL	454.5	455.0	454.3	458.3	EnCana Oil & Gas Co. Ltd.	shut in
		00/05-18-068-03W4	CNRL	489.0	491.0	489.0	492.4	EnCana Oil & Gas Co. Ltd.	shut in
		00/12-19-068-03W4				492.5	493.0	EnCana Oil & Gas Co. Ltd.	not produce
		AA/09-01-068-04W4				460.0	463.9	CNRL	not produce
		AA/15-01-068-04W4				461.7	462.5	CNRL	not produce
		AA/08-12-068-04W4				471.8	476.3	CNRL	not produce
		00/16-12-068-04W4	CNRL	481.0	482.0	481.0	483.0	EnCana Oil & Gas Co. Ltd.	shut in
		AA/04-13-068-04W4				481.5	483.5	CNRL	not produce
		00/07-13-068-04W4				474.0	479.0	CNRL	not produce
		00/08-13-068-04W4	CNRL	480.0	481.0	480.0	482.0	EnCana Oil & Gas Co. Ltd.	shut in
		AA/10-14-068-04W4				472.5	476.0	CNRL	not produce
		AA/07-23-068-04W4				488.8	490.0	CNRL	not produce
		00/09-23-068-04W4				492.0	492.6	EnCana Oil & Gas Co. Ltd.	not produce
		00/02-24-068-04W4	CNRL	482.0	485.0	481.8	486.0	EnCana Corporation	shut in
		02/02-24-068-04W4				481.5	485.7	EnCana Corporation	not produce
		AA/04-24-068-04W4				474.0	480.0	CNRL	not produce
		00/14-24-068-04W4				489.8	492.0	EnCana Oil & Gas Co. Ltd.	not produce
		00/03-25-068-04W4	CNRL	486.0	488.0	486.6	489.0	EnCana Oil & Gas Co. Ltd.	shut in
		00/10-26-068-04W4	CNRL	492.0	494.5	491.4	494.9	EnCana Corporation	shut in
		00/10-33-068-04W4	CNRL, Husky	485.0	486.0	485.0	489.3	CNRL	shut in

Table 1. List of Subject Wells

Field	Pool	Unique Well Identifier	Applicant	Company Top Perf. Depth (TVD)	Company Base Perf. Depth (TVD)	Board Pay Top Depth (TVD)	Board Pay Base Depth (TVD)	Licensee	Decision
Fisher (cont.)	Clearwater E (cont.)	02/10-33-068-04W4	Husky/np	476.2*	480.2**	476.2	480.2	CNRL	not produce
		AA/14-33-068-04W4				484.5	487.0	CNRL	not produce
		00/10-35-068-04W4				489.3	490.0	EnCana Oil & Gas Co. Ltd.	not produce
		00/05-02-069-04W4	Husky/np	496.8*	500.0**	496.8	500.0	EnCana Corporation	not produce
		00/05-03-069-04W4				498.4	500.0	EnCana Corporation	not produce
		00/08-03-069-04W4	Husky/np	494.0*	499.2**	494.0	498.6	EnCana Oil & Gas Co. Ltd.	not produce
		03/08-03-069-04W4	Husky	495.5	497.5	495.5	500.0	EnCana Oil & Gas Co. Ltd.	shut in
		00/03-04-069-04W4				489.5	492.8	Husky Oil Operations Limited	not produce
		00/07-09-069-04W4				497.5	502.0	EnCana Oil & Gas Co. Ltd.	not produce
		00/05-10-069-04W4	Husky	500.3	501.3	500.2	503.0	EnCana Corporation	shut in
		02/05-10-069-04W4				500.5	503.5	EnCana Corporation	not produce
	Clearwater EE	00/05-13-069-06W4	Husky	476.0	480.0	478.0	480.0	EnCana Oil & Gas Co. Ltd.	produce
		00/08-14-069-06W4				481.0	481.8	EnCana Oil & Gas Co. Ltd.	produce
	Clearwater G	00/07-19-069-05W4				456.0	456.5	EnCana Oil & Gas Co. Ltd.	not produce
		00/06-20-069-05W4	Husky	445.2	446.5	445.0	447.7	EnCana Corporation	shut in
	Clearwater PP	00/10-22-067-05W4	CNRL	448.0	511.0	459.0	461.5	CNRL	shut in
	Clearwater S	02/14-09-070-05W4				431.0	431.5	EnCana Corporation	not produce
		00/06-15-070-05W4				433.2	433.7	EnCana FCCL Oils Sands Ltd.	not produce
		00/13-15-070-05W4				421.5	425.2	EnCana Oil & Gas Co. Ltd.	not produce
		00/05-16-070-05W4	Husky	425.0	425.5	425.0	427.5	EnCana Oil & Gas Co. Ltd.	shut in
		00/06-17-070-05W4				433.0	433.4	EnCana Corporation	not produce
		00/15-17-070-05W4				428.5	432.0	EnCana Corporation	not produce
		00/02-18-070-05W4				423.5	424.2	EnCana Corporation	not produce
		00/07-20-070-05W4	Husky/np	437.0*	438.3**	437.0	438.3	EnCana Corporation	not produce
		00/01-21-070-05W4				419.0	426.0	EnCana FCCL Oils Sands Ltd.	not produce
		00/06-21-070-05W4	Husky	417.0	422.0	415.8	426.0	EnCana Corporation	shut in
		00/05-22-070-05W4	Husky	422.5	423.5	422.4	423.6	EnCana Oil & Gas Co. Ltd.	shut in
		02/05-22-070-05W4				424.0	425.0	EnCana FCCL Oils Sands Ltd.	not produce
	Clearwater T	00/05-13-069-06W4	Husky	468.0	470.0	468.5	469.8	EnCana Oil & Gas Co. Ltd.	shut in
		00/08-14-069-06W4				470.5	471.5	EnCana Oil & Gas Co. Ltd.	not produce
	Clearwater TT	00/03-11-070-06W4	Husky	437.0	438.0	436.5	439.2	EnCana Corporation	shut in
	Clearwater U/D 006	00/11-13-070-05W4	Husky	442.5	445.0	443.0	445.0	EnCana FCCL Oils Sands Ltd.	produce
	Clearwater U/D 052	00/08-26-069-05W4	Husky	435.5	436.5	436.0	437.0	EnCana Corporation	shut in
	Clearwater U/D 093	00/07-31-068-04W4				479.3	481.0	CNRL	not produce
		AA/10-31-068-04W4				480.6	482.0	CNRL	not produce
		00/14-31-068-04W4	EnCana Prod.	474.0	474.5	474.0	474.6	EnCana Corporation	not produce
		AA/14-31-068-04W4				474.7	475.3	CNRL	not produce

Table 1. List of Subject Wells

Field	Pool	Unique Well Identifier	Applicant	Company Top Perf. Depth (TVD)	Company Base Perf. Depth (TVD)	Board Pay Top Depth (TVD)	Board Pay Base Depth (TVD)	Licensee	Decision
Moore	Clearwater B	00/09-05-068-03W4				470.0	470.5	EnCana Corporation	not produce
		00/08-07-068-03W4				490.3	491.3	EnCana Oil & Gas Co. Ltd.	not produce
		00/10-08-068-03W4	CNRL	*474.0	^478.0	471.7	476.0	EnCana Corporation	shut in
		02/10-08-068-03W4				472.5	476.0	EnCana Corporation	not produce
		00/12-09-068-03W4				474.0	477.5	CNRL	not produce
		02/12-09-068-03W4	CNRL	475.0	476.0	475.0	478.0	CNRL	shut in
		00/05-15-068-03W4	CNRL	491.0	493.0	491.0	498.0	EnCana Oil & Gas Co. Ltd.	shut in
		00/07-16-068-03W4	CNRL	495.0	497.0	495.0	500.5	EnCana Corporation	shut in
		00/10-16-068-03W4				487.0	490.8	EnCana Oil & Gas Co. Ltd.	not produce
		00/05-17-068-03W4	CNRL	483.0	484.0	483.7	485.0	EnCana Oil & Gas Co. Ltd.	shut in
		00/10-21-068-03W4	CNRL	472.5	476.5	472.6	478.0	EnCana Corporation	shut in
		02/10-21-068-03W4				472.5	477.6	EnCana Corporation	not produce
		00/10-29-068-03W4				488.0	490.4	EnCana Corporation	not produce
		02/10-29-068-03W4				487.0	488.0	EnCana Oil & Gas Co. Ltd.	not produce
		00/15-29-068-03W4	CNRL	483.0	486.0	485.0	487.5	EnCana Oil & Gas Co. Ltd.	shut in
		00/15-30-068-03W4				483.3	484.8	EnCana Oil & Gas Co. Ltd.	not produce
		00/06-31-068-03W4				482.8	483.6	EnCana Corporation	not produce
		00/10-31-068-03W4				484.0	485.0	EnCana Corporation	not produce

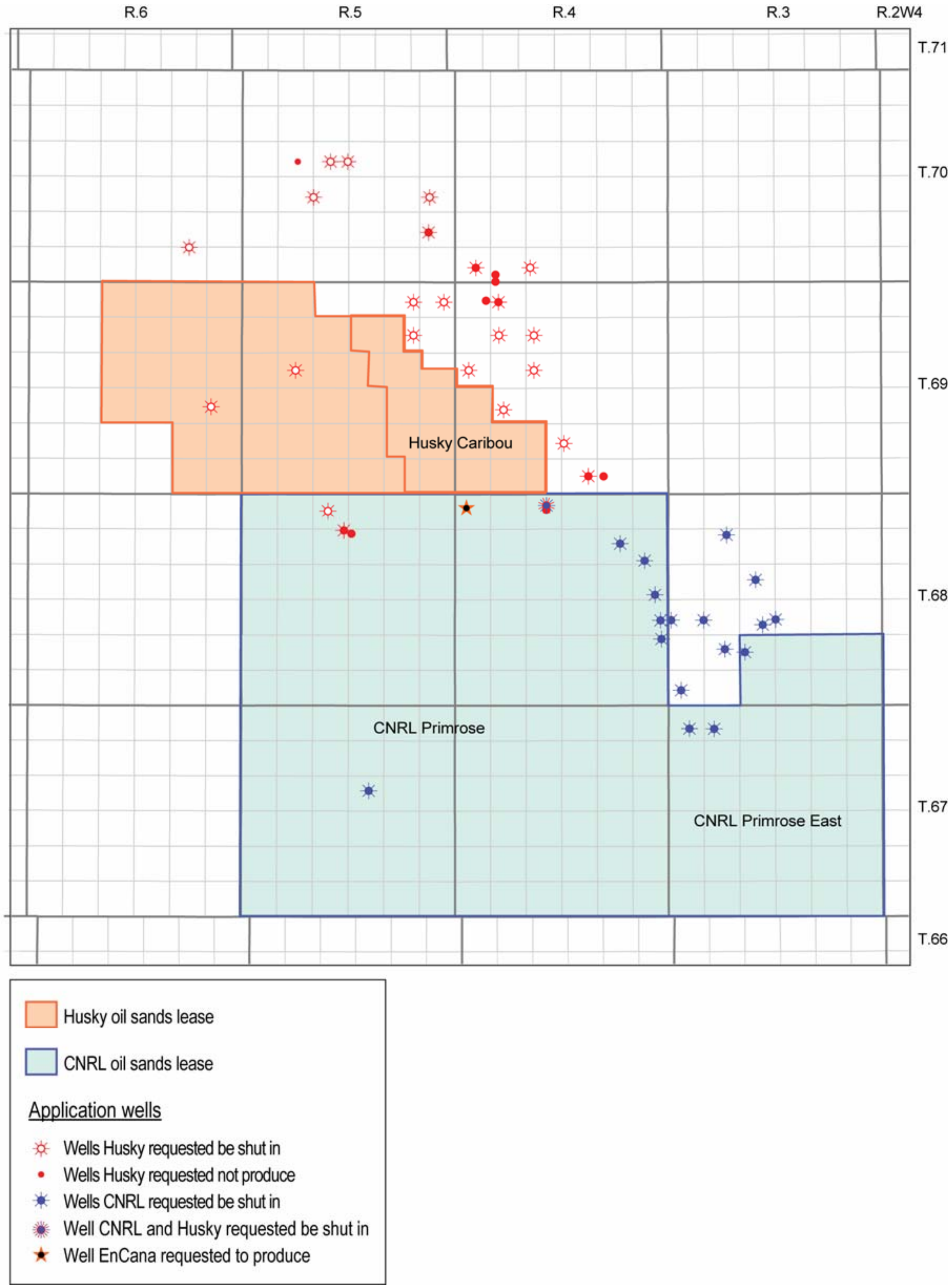

Figure 1. Location map with application wells

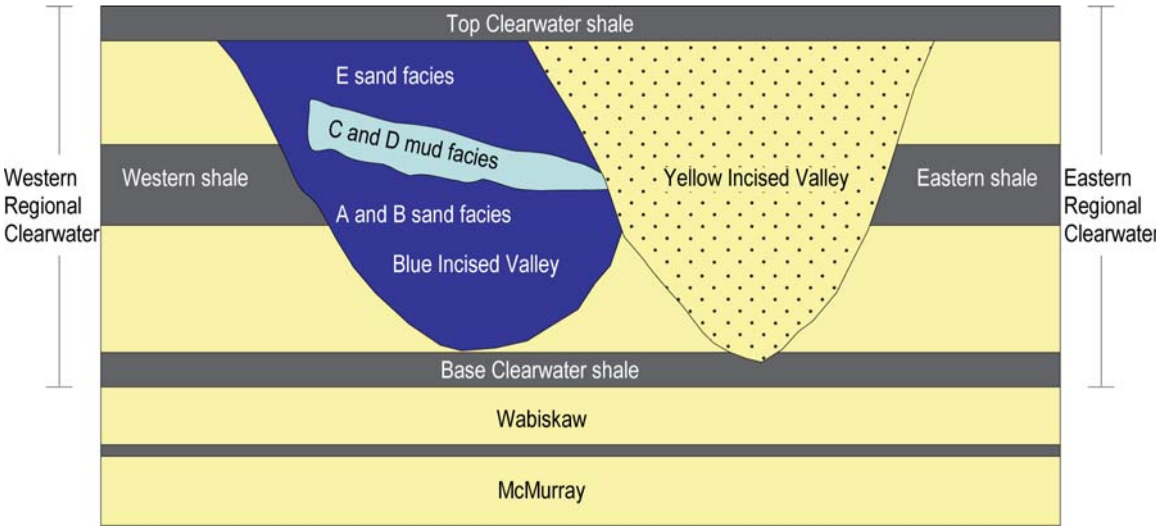

Figure 2. Clearwater Formation schematic section

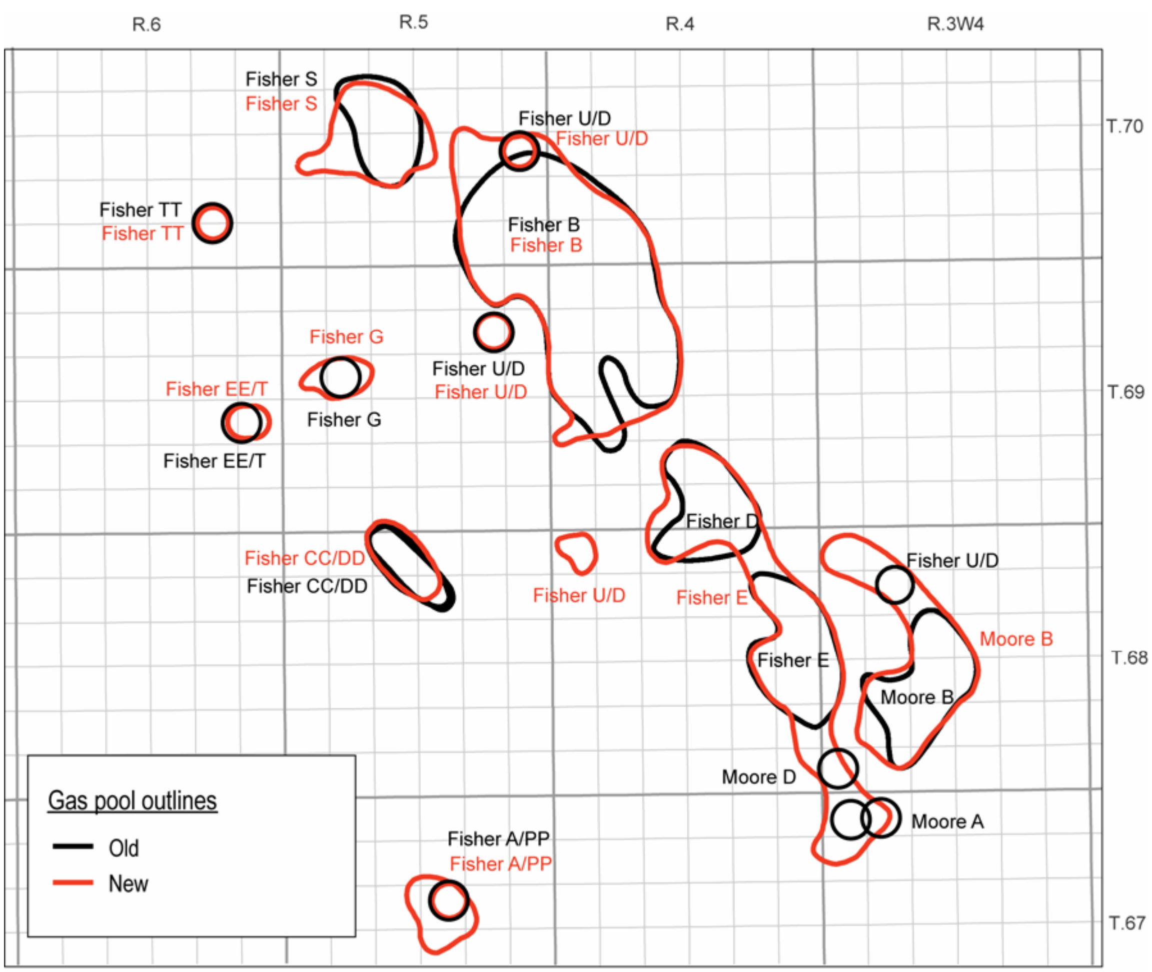

Figure 3. Old and new Board gas pool outlines

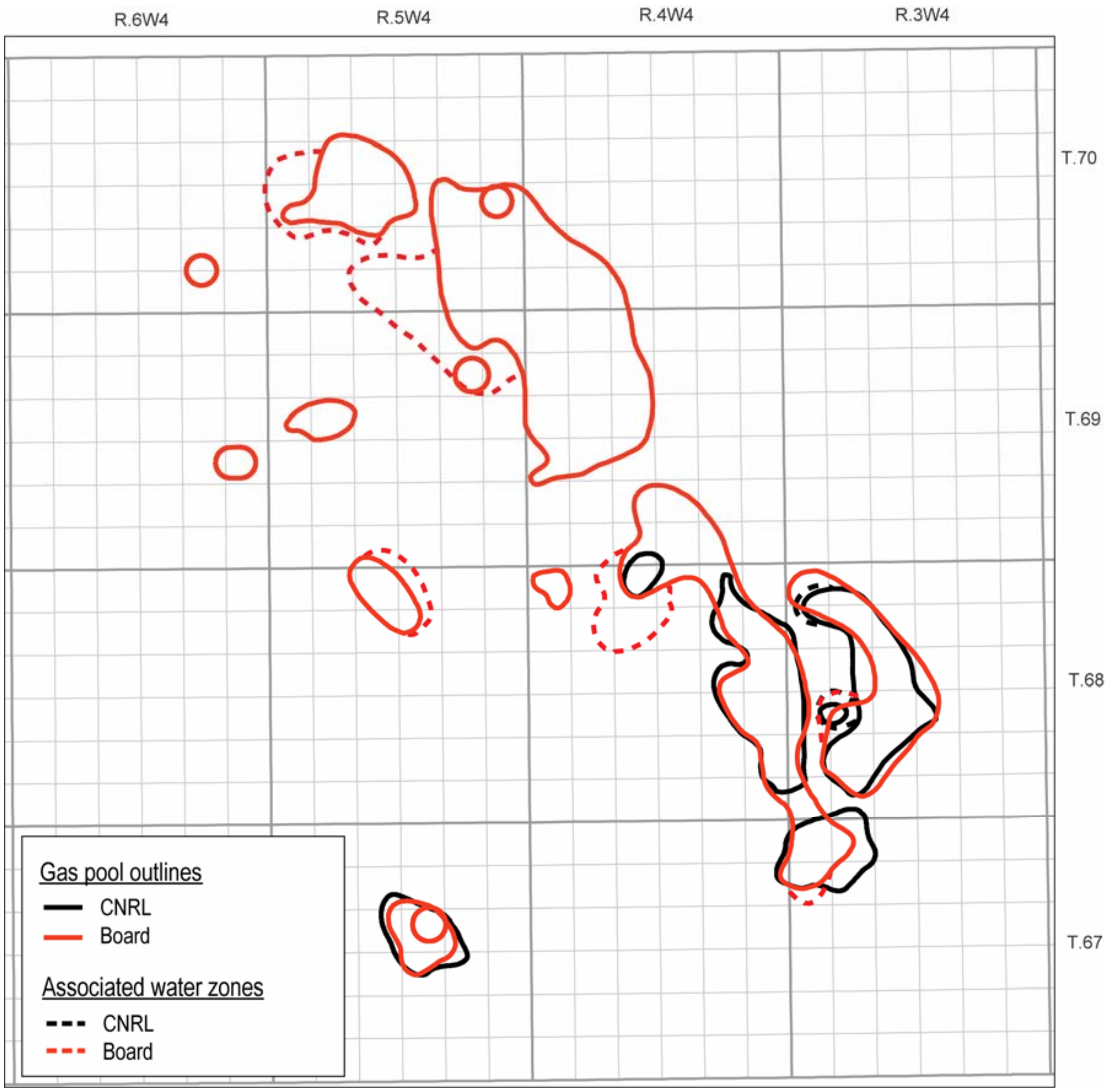

Figure 4. CNRL and new Board gas pool outlines and associated water zones

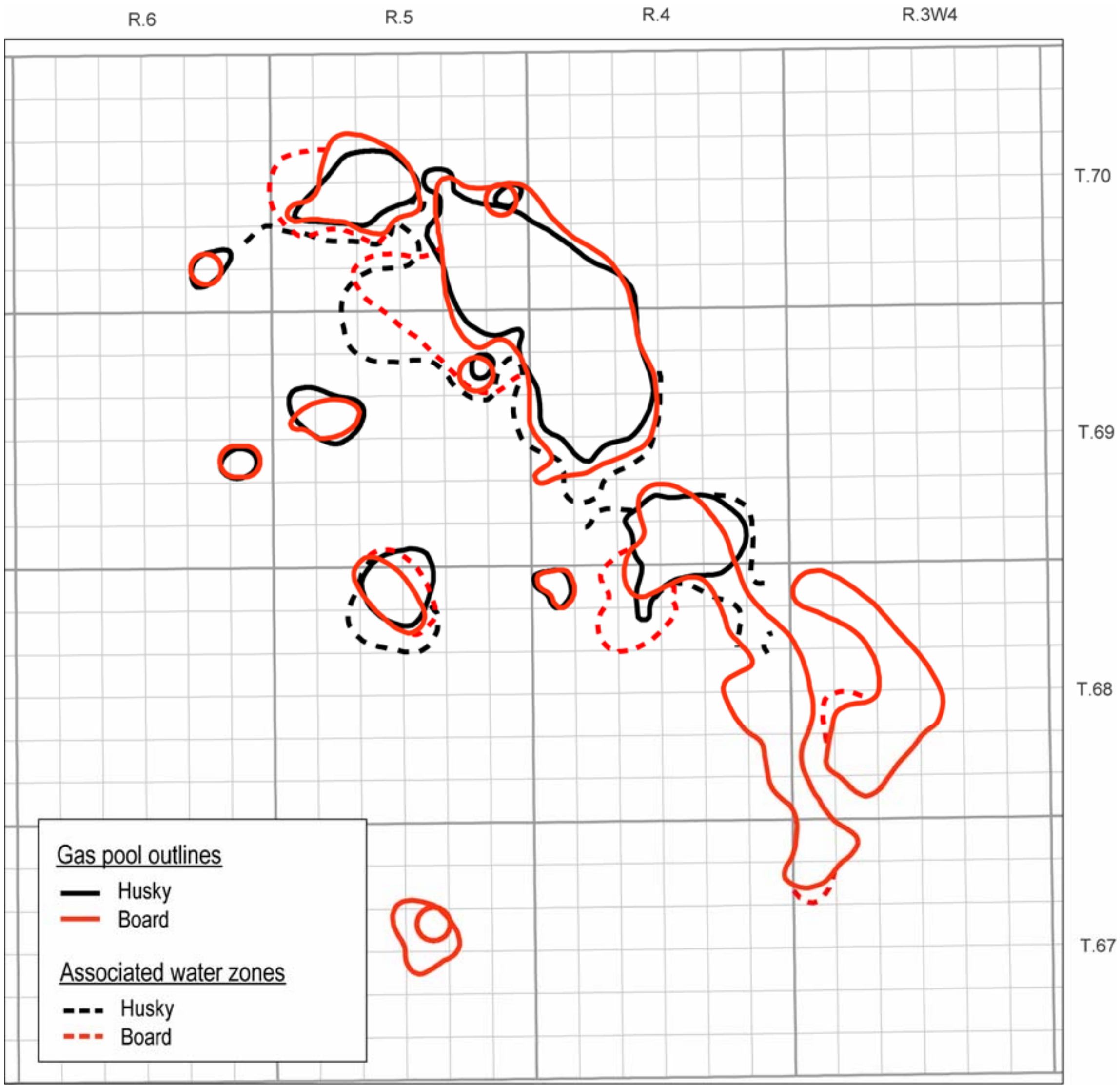

Figure 5. Husky and new Board gas pool outlines and associated water zones

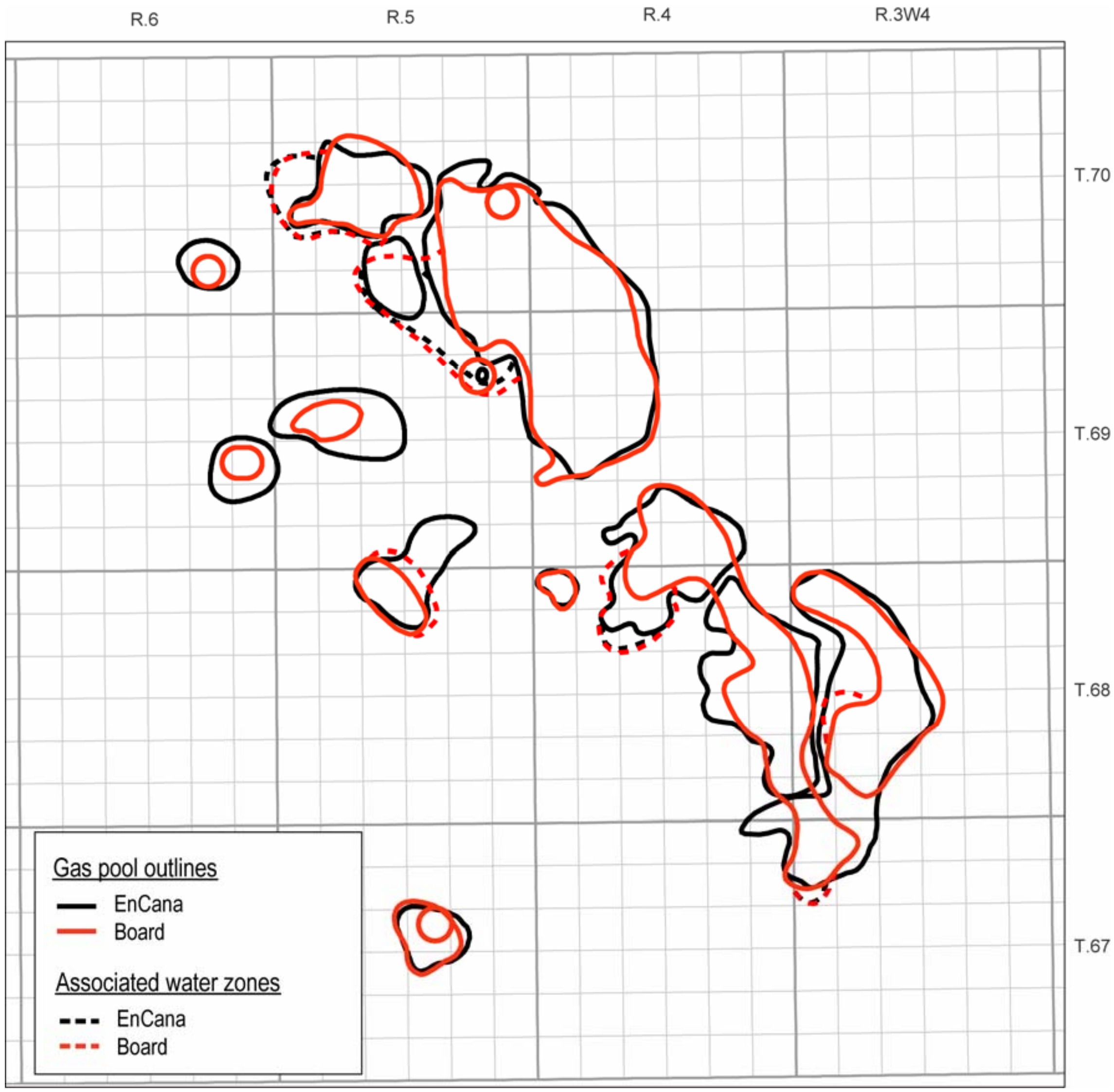

Figure 6. EnCana and new Board gas pool outlines and associated water zones

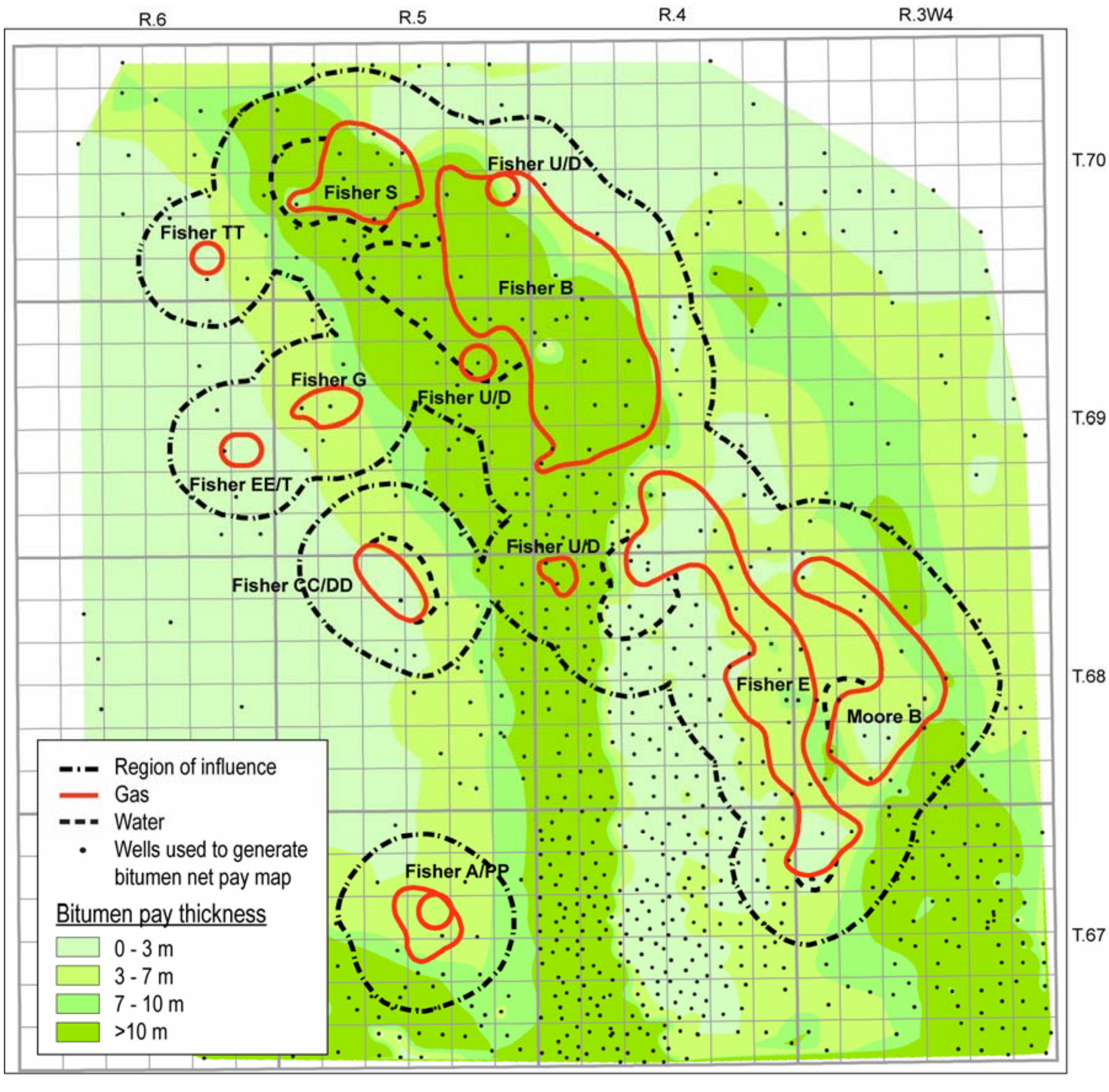

Figure 7. Board net bitumen pay, gas pooling and associated water zones, and region of influence map