Duvernay Oil Corp. and Murphy Oil Company Ltd.

Applications for the Production and Shut-in of Gas from the Seal Bluesky A Pool Peace River Oil Sands Area

December 18, 2007

Alberta Energy and Utilities Board

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Decision 2007-108: Duvernay Oil Corp. and Murphy Oil Company Ltd., Applications for the Production and Shut-in of Gas from the Seal Bluesky A Pool, Peace River Oil Sands Area

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Calgary Alberta

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APPLICATIONS FOR THE PRODUCTION AND SHUT-IN OF GAS FROM THE SEAL BLUESKY A POOL PEACE RIVER OIL SANDS AREA

Decision 2007-108
Applications No. 1514341 and 1514722

1 DECISION

Having considered all the evidence, the Alberta Energy and Utilities Board (EUB/Board)

- denies Application No. 1514341, submitted by Murphy Oil Canada by its Managing Partner Murphy Oil Company Ltd. (Murphy), to shut in gas production from the Bluesky Formation (Bluesky) from the well located at Legal Subdivision (LSD) 8, Section 24, Township 82, Range 16, West of the 5th Meridian (8-24 well), and
- grants Application No. 1514722, submitted by Duvernay Oil Corp. (Duvernay) to produce Bluesky gas from the well located at LSD 1-25-82-16W5M (1-25 well).

The Board is not convinced that the available evidence shows that the region of influence (ROI) of the Seal Bluesky A Pool (A Pool) should be significantly extended beyond the edge of the gas pool or that it shows that the bitumen within the ROI is potentially recoverable.

There may be a need in the future to reassess the appropriateness of continued gas production from the A Pool if additional information becomes available on the ROI and/or the potential to recover the underlying bitumen. In this regard, the Board requires Pearl Exploration and Production Ltd. (Pearl), operator of the 8-24 well, and Duvernay to continue to obtain pressure measurements at the 8-24 and 1-25 wells and to submit annual reports to the EUB and Murphy. The details of the required pressure monitoring and reporting are provided in Section 7.3.

2 INTRODUCTION

2.1 Applications

The Board considered the following two applications at the hearing held on October 4 to 10, 2007:

- Application No. 1514341, submitted by Murphy for the shut-in of Bluesky gas at the 8-24 well; and
- Application No. 1514722, submitted by Duvernay for approval to produce Bluesky gas at the 1-25 well.

Figure 1 is a location map for the application area.

At the time the hearing was scheduled, two other applications were to be considered: Application No. 1456596, submitted by Canadian Natural Resources Limited (CNRL) for approval to produce Bluesky gas at the well located at LSD 14-27-82-16W5M (14-27well), and Application

No. 1477294, submitted by Galleon Energy Inc. for approval to produce gas from the Gething Formation at the well located at LSD 16-22-82-16W5M. However, these two applications were subsequently withdrawn and therefore not considered at the hearing.

2.2 Interventions

Pearl, as operator and 50 per cent working interest owner of the 8-24 well, submitted an objection to Application No. 1514341. However, Pearl did not provide any witnesses at the hearing. Since Pearl's submission could not be tested, the Board has given it appropriate weight in its decision.

Murphy objected to Application No. 1514722 because it was concerned that increased gas production from the A Pool would continue to cause exsolution of solution gas from the bitumen that it owned underlying and surrounding the A Pool, removing the primary drive mechanism for bitumen recovery.

2.3 Hearing

The Board held a public hearing of the applications and interventions in Calgary, Alberta, from October 4 to October 10, 2007, before Board Member J. D. Dilay, P.Eng. (Presiding Member) and Acting Board Members R. J. Willard, P.Eng., and C. D. Hill. Those who appeared at the hearing are listed in Appendix 1.

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 Oil Sands Areas (OSA). The three applications were

- two applications by EnCana Oil & Gas Partnership (EnCana) and CNRL regarding the production and shut-in of gas from the Clearwater Formation in the Cold Lake OSA; and
- an application by Koch Exploration Canada Corporation (Koch) regarding the shut-in of Bluesky gas in the Peace River OSA.

The applications by EnCana and CNRL and the possible need for a broader bitumen conservation strategy in the Cold Lake OSA were dealt with in *Decision 2007-056,*[2] but a hearing on the Koch application was not held because Koch subsequently withdrew its application. The Board considers the statement in *Bulletin 2006-14* regarding the possible need for a broader bitumen conservation strategy in the Peace River OSA to be relevant to the subject hearing.

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.

2 *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.

4 ISSUES

The Board considers the issues respecting the applications to be

- geology and mapping of gas, bitumen, and water,
- reservoir continuity and ROI,
- potential recoverability of the bitumen within the ROI, and
- need for a bitumen conservation strategy for the Peace River OSA.

The Board notes that Duvernay agreed that where primary bitumen production is considered to be feasible, solution gas drive is an important drive mechanism for bitumen recovery and associated gas production should not be allowed. Therefore, the effect of associated gas production on primary bitumen recovery (where the recovery is considered to be feasible) was not an issue at this hearing.

The Board also notes that at various times, Duvernay and Murphy referred to the liquid hydrocarbon in the Bluesky as bitumen or heavy oil. The Board understands that this distinction referred to the physical properties of the liquid hydrocarbon, such as its viscosity and density, and its potential for primary production. However, from the Board’s perspective, the liquid hydrocarbon in the Bluesky within the Peace River OSA is deemed to be bitumen and is referred to as bitumen throughout this report.

5 GEOLOGY AND MAPPING OF GAS, BITUMEN, AND WATER

5.1 Views of Duvernay

Geology

Duvernay interpreted the Bluesky to have been deposited within distributary channels and interdistributary settings with some possible estuarine influences, overlain by a transgressive lag deposit, as shown in Figure 2. Duvernay’s interpretation was based on the morphology, the linearity and bifurcation of the clean sands, an analysis of the core of its two wells, and papers written on the Bluesky deposits in the area that indicated a more fluvial environment.

Duvernay interpreted the A Pool to be within the interdistributary facies, which it described as silt and fine-grained sands, with the common occurrence of beds of coal and thin shales. Duvernay believed that beyond the edges of the gas pool, the interdistributary facies contained viscous bitumen, interbedded with water-bearing sands, and that this facies was permeable to gas and water at porosities greater than 15 per cent but the bitumen was immobile. Duvernay’s in situ permeability test at the 1-25 well measured a permeability of 83 millidarcies.

Duvernay observed that the productive bitumen in the Seal Area was confined to the north/south trending channel facies, which was composed of medium to coarse grained, relatively clean sands with some possible estuarine influences. Duvernay stated that the channel facies exhibited porosities to 32 per cent and core-derived air permeabilities of 1 to 5 darcies. Duvernay identified and mapped the location and extent of the distributary channels based on seismic data and did not expect increased infill drilling beyond the edge of the channel sands to encounter further channel deposits.

Duvernay stated that a transgressive lag deposit was present overlying both the interdistributary and the channel facies, which was usually glauconitic, of 1.5 to 4 metres (m) in thickness, fine to medium grained, and potentially calcareous to the point of being tight. Duvernay was able to identify the transgressive lag on logs, as it appeared to be cleaner than the interdistributary deposits, but it was not always recognizable when overlying the channel deposit. Duvernay disagreed with Murphy that this unit was porous and permeable throughout the area.

Mapping of Gas

Duvernay submitted a seismic montage that showed gas in the A Pool to be trapped within a closed structural high, geophysically mappable from two-dimensional (2-D) seismic as an amplitude bright spot. Duvernay believed that the areal extent of the gas pool as determined by seismic was consistent with the structural closure that it mapped geologically. Duvernay's estimate of the areal extent of the A Pool was 550 hectares (ha) from its seismic amplitude anomaly map compared to 453 ha from its geologic map.

Duvernay identified the presence of Bluesky gas from a sonic-neutron cross plot and determined net gas pay using a density porosity cutoff of 15 per cent, a normalized shale cutoff of 67.5 API gamma units, and resistivities generally greater than 10 ohm-m. Duvernay interpreted 5.9 m and 5.8 m net gas pay in the 8-24 and 1-25 wells respectively and pooled them together based on structure, pressures, log evaluation, gas production, and a common gas/water contact at approximately +54 m to +56 m subsea (SS). Duvernay interpreted the subject wells to exhibit gas over water over thin bitumen. Duvernay interpreted the A Pool to be isolated from the other gas wells in the township based on gas/water contacts and different reservoir pressures. It believed that the A Pool did not extend onto Murphy's proposed and ongoing bitumen projects to the north and east. Duvernay's estimate of the areal extent of the A Pool and that of other gas pools in the vicinity of the A Pool are shown in Figure 3.

Duvernay's volumetric estimates of the original gas in-place (OGIP) for the A Pool were 237 million cubic metres (10^6 m^3) and 194 10^6 m^3 from its seismic and geologic maps respectively, while its material balance estimate was 175 10^6 m^3.

Mapping of Bitumen

To identify porous and permeable rock saturated with bitumen, Duvernay used a clean sand cutoff of 60 API gamma units and a density porosity cutoff of 21 per cent (sandstone matrix). Where the density tool was not available, it used a 310 microseconds per metre sonic cutoff. Duvernay assigned bitumen pay where gas was not indicated by sonic logs or neutron/density logs, where the resistivity was a minimum of 30 ohm-m, and by available test data. From its log analysis, Duvernay interpreted net bitumen thicknesses of 0.6 m and 0 m at the 8-24 and 1-25 wells respectively.

Duvernay noted the presence of bottom water with no top water in the channel, which suggested typical relative positioning of water with bitumen having a gravity greater than 10 degrees API. Duvernay therefore interpreted the bitumen in and to the east of the channel to be compositionally lighter than the bitumen underlying the subject wells.

Duvernay submitted a Bluesky net bitumen thickness map but did not believe that it had sufficient data to determine if the bitumen could be producible in the presence of water-bearing sands. It stated that viscosity data and the relative proportion of water-bearing rock to bitumen-bearing rock were needed to determine net pay. Noting that the bitumen within the interdistributary facies was overlain by water, Duvernay stated that in its experience, bitumen overlain or interbedded with 2 m or more of aerially extensive formation water would preferentially produce formation water with little or no bitumen.

Duvernay provided several estimates of the original bitumen in-place (OBIP), including

- 7.7 10^6 m^3 for the regional Bluesky and Gething for 12 sections that included and surrounded the 8-24 and 1-25 wells;
- 11.6 10^6 m^3 for the regional Bluesky for about 33 sections that included and surrounded the 8-24 and 1-25 wells; and
- 80.9 10^6 m^3 for the channel Bluesky for the same area as that in the second bullet.

Mapping of Water
Duvernay interpreted the interdistributary or regional deposits on both sides of the productive bitumen channel to be water bearing. Duvernay believed that water-bearing strata represented over 50 per cent of the reservoir in the Bluesky over its lands.

To determine the net water thickness, Duvernay used a gamma cutoff of 67.5 API for clean sand, a water resistivity (Rw) of 0.5 ohm-m, and a reservoir resistivity (Rt) of 20 ohm-m. Duvernay believed this to be a maximum Rt cutoff for water-bearing zones and found this would represent a water saturation of 55 per cent in a clean sand that had an average porosity of 27 per cent. Duvernay noted that a 20 ohm-m resistivity indicated water saturation of 80 per cent in a clean sand that had an average porosity of 15 per cent. On the basis of these cutoffs, Duvernay assigned 8.4 m and 7.1 m of net water thickness to the 8-24 and 1-25 wells respectively.

In constructing its net water thickness map, Duvernay did not differentiate water vertically within the Bluesky interval. Duvernay evaluated each well for the presence of water and mapped the thickness of the total water; therefore, the water within one well was not necessarily connected with water in the adjacent well. Duvernay emphasized that its water map did not represent interconnected water.

5.2 Views of Murphy

Geology
Murphy’s working model for the Bluesky in the Seal Area was a barrier bar complex, as shown in Figure 2. Murphy stated that this interpretation was consistent for the most part with core observations, although certain elements of the model, such as a tidal inlet and ebb tidal delta, had not been observed with any confidence in core. Murphy believed that core examination revealed several mappable units within the Bluesky that were separated by distinct and correlatable stratigraphic surfaces. Murphy interpreted the mappable units to include a coal/marsh interval separating the lower Bluesky from the upper Bluesky, a sand-rich reservoir, a muddy interbedded reservoir, and a transgressive sand.

Murphy based its depositional model on the sedimentary structures and fossil assemblage it observed in core, which it believed indicated a strong marine influence on the depositional environment. Murphy disagreed with Duvernay’s interpreted channel environment based on the lack of dominance of clean, mud-free sands containing primary current ripples. Murphy believed that the high energy level in a channel system and the association of fresh water would be biologically stressful and would typically preclude colonization by fauna.

Murphy interpreted two distinct reservoir types to be present within the barrier bar complex: the good quality reservoir associated with the linear barrier bar and the poorer quality reservoir associated with the middle to lower shoreface environment. Both reservoirs were bracketed, top and bottom, between two laterally extensive erosion surfaces. Murphy found that the good reservoir consisted of relatively clean sand containing thin, discontinuous, mud laminae preserved as drapes over oscillation ripple structures and that within the best reservoirs the mud laminae made up less than 5 per cent of the deposit. Murphy interpreted the clean reservoir sands to be enveloped within and merged laterally into a facies with greater abundance of mud laminae and increasing amounts of bioturbation, which it called the interbedded muddy reservoir. Murphy believed that the sand beds and laminae in the interbedded muddy reservoir were not argillaceous and that the sand laminae were generally clean, with good bitumen saturation. Murphy believed that the amount of discrete mud laminae determined the quality of a reservoir.

Murphy stated that an erosional discontinuity observed at the top of the Bluesky was overlain by a thin transgressive sand (1 to 5 m thick), which was the result of wave erosion and reworking of the underlying Bluesky. Murphy found that the transgressive sand was difficult to differentiate on logs where it overlaid clean reservoir sands, but was observable in many cores as an abrupt change in grain size or by the presence of coarse erosional lag. Murphy stated that the sand tended to be thinner where it overlaid the interbedded muddy reservoir facies, presumably because less sand was available to rework. Murphy believed this transgressive sand formed a continuous, porous, and permeable pathway everywhere at the top of the Bluesky. Murphy interpreted that it formed all or part of the gas reservoirs, whereas beyond the gas reservoirs it was saturated with bitumen. Murphy noted that its transgressive sand appeared to be equivalent in part to the transgressive lag interpreted by Duvernay.

Mapping of Gas

Murphy mapped the A Pool based on structural closure and its amplitude contour seismic map. Murphy's areal extent of the A Pool and that of other gas pools in the vicinity of the A Pool are shown in Figure 3. To define net gas pay, Murphy used a porosity cutoff of 24 per cent and a resistivity cutoff of 10 ohm-m. On the basis of pressure data, Murphy mapped the 8-24 and 1-25 wells in the same pool with net gas pays of 5.6 m and 5.5 m respectively. Murphy's volumetric estimate of the OGIP for the A Pool ranged from 171 to 223 10^6 m^3; it also estimated an OGIP of 150 to 169 10^6 m^3 by extrapolation of the production data for the 8-24 well.

Mapping of Bitumen

To determine intervals with good to excellent pay, where the bitumen saturation was greater than 65 per cent, Murphy used a porosity cutoff of 24 per cent or greater and resistivity greater than 20 ohm-m. For a poorer quality reservoir, with bitumen saturation between 50 and 65 per cent, Murphy used a porosity cutoff of 24 per cent and resistivity of 10 to 20 ohm-m. Murphy assigned 2.5 m and 4.9 m of net bitumen pay to the Bluesky in the 8-24 and 1-25 wells respectively. Murphy provided several estimates of the OBIP, including

- 15.7 10^6 m^3 for the Bluesky for about 9 sections that included and surrounded the 8-24 and 1-25 wells;

- 35.0 – 51.0 10^6 m^3 for the Bluesky for about 14 sections that included and surrounded the 8-24 and 1-25 wells; and
- 197.3 – 284.1 10^6 m^3 for the Bluesky for about 60 sections that included and surrounded the 8-24 and 1-25 wells.

Murphy concluded that the delineation drilling of one well per section could result in bypassed opportunity for bitumen.

Mapping of Water

Murphy stated that top and/or bottom water existed in the area. Murphy mapped a region that it called " 'Top' High-Sw Mobile Water," which had a water saturation (Sw) greater than 35 to 40 per cent and an Rt less than 10 ohm-m. This region included wells 8-24, 1-25, and 14-27, for which Murphy assigned water thicknesses of 1.8, 2.0, and 1.6 m respectively. However, Murphy stated that its mapping was meant to show an "average isopach" rather than any direct continuity among the wells. Murphy used the same cutoffs to map a region that it called " 'Bottom' High-Sw Mobile Water" to the east of the A Pool, within its barrier bar deposit.

Murphy disagreed with Duvernay's interpretation of the extent and thickness of water zones and believed that Duvernay had identified mud and shale as water, which resulted in lower than expected average net bitumen pay for the area.

5.3 Views of the Board

Geology

The Board recognizes that there is disagreement between Murphy and Duvernay on the depositional model for the Bluesky in the Seal Area. The Board believes that knowledge of the depositional environment can assist in understanding reservoir quality and continuity. However, the Board is of the view that insufficient evidence was provided to demonstrate if, and if so, how, the depositional environment had any influence on reservoir continuity in the subject area.

The Board notes that both parties agreed that there are two different reservoir lithologies in the Seal Area: a poor quality muddy reservoir consisting of interlaminated silts, sands, and shales, which is host to the A Pool, and a north/south trending good quality sand reservoir, which is bitumen producing to the east and flanks the poorer reservoir both to the east and to the west. Although the Board makes no comment as to the nature of the depositional environment of the Bluesky in the subject area, it agrees with both parties that there are two distinct reservoir facies present. For the purposes of this report, the Board will refer to the good quality clean sand reservoir as the "channel deposit" and the poor quality muddy reservoir as "interbedded muddy facies."

The Board notes that both parties recognize the presence of a transgressive deposit at the top of the Bluesky. The Board accepts Murphy's statement that the transgressive sand is the result of wave erosion and reworking of the underlying Bluesky and that this deposit tends to be thinner where it overlies the interbedded muddy facies. The Board believes that there were likely areas within the interbedded muddy facies where there was very little sand available to rework, and therefore very little sand to redeposit. Consequently, the Board is not convinced that there is a porous and permeable transgressive sand everywhere at the top of the Bluesky, as interpreted by Murphy.

Mapping of Gas

The Board interprets 5.0 m and 5.9 m net gas pay in the 8-24 and 1-25 wells respectively, which is generally consistent with the net gas pay interpreted by both parties. Figure 3 illustrates the comparable areal extent of the Bluesky gas pools, as interpreted by Duvernay and Murphy. With respect to the A Pool, the Board notes that Murphy's western boundary extends farther into section 23 than that of Duvernay, but the northern and eastern boundaries of both parties are very similar. In the Board's view, the northern and eastern boundaries have the most impact on this decision, as they could affect the proximity of the ROI of the gas production to the main bitumen-producing channel or to the proposed bitumen project to the north. Given the similarities between the parties, the Board accepts the northern and eastern zero edges of the A Pool as submitted.

Mapping of Bitumen

Using cutoff values of 20 ohm-m resistivity and 24 per cent porosity, the Board interprets net bitumen pay of 2 m and 1.7 m for the 8-24 and the 1-25 wells respectively. The Board interprets somewhat greater net pay thicknesses than Duvernay, as it considers the 30 ohm-m resistivity cutoff used by Duvernay to be too high and that it may bypass bitumen pay in zones with porosities higher than 21 per cent. The Board interprets less bitumen pay than Murphy because the Board does not vary its cutoffs when determining net pay in the poorer quality reservoir. The Board believes that this would result in an optimistic representation of the potential for bitumen production from shaly zones. Notwithstanding the differences of interpreted net bitumen pay, the Board finds that overall there is minimal bitumen thickness underlying the subject gas pool.

Regarding the OBIP values provided by Duvernay and Murphy, the Board observes that the values are not directly comparable because they represent different areas and do not include a similar mix of the channel deposit and the interbedded muddy facies.

Mapping of Water

The Board interprets 1.5 m and 2.4 m of water below the gas and above the bitumen (top water) in the 8-24 and 1-25 wells respectively and notes that its net top water thickness for the A Pool is similar to that of Murphy. The Board uses a cutoff of 10 ohm-m, combined with a negative shift in the spontaneous potential (SP) curve, to indicate the presence of water. The Board disagrees with Duvernay that a 20 ohm-m resistivity cutoff is indicative of water in a clean porous sand.

The Board uses top water maps to determine if the ROI of gas production should be extended beyond the zero edge of a gas pool. The water maps submitted by Duvernay and Murphy did not demonstrate interconnected top or bottom water; therefore there was no evidence to suggest that the ROI of the pool could be extended by pressure communication through a continuous underlying water zone. The water maps submitted by the parties were consequently not used by the Board to determine potential reservoir communication.

6 RESERVOIR CONTINUITY AND REGION OF INFLUENCE

6.1 Views of Duvernay

Duvernay maintained that the A Pool was separate from the bitumen-producing channel and adjacent gas wells and that there was evidence of reservoir compartmentalization throughout the subject area. Duvernay interpreted this to be due to multiple factors, including discontinuity of the argillaceous silts and fine-grained muddy sands of the interdistributary area, block faulting within the Peace River Arch separating otherwise correlative intervals, calcite cementation, and the high-viscosity bitumen within the interdistributary deposits acting as a seal.

Vertical Continuity

Duvernay believed that there were no continuous vertical permeability barriers present within the interdistributary facies or within the channel deposits.

Lateral Continuity and Permeability Barriers

Duvernay submitted that although its reservoir facies model differed from that of Murphy, the argillaceous silts and fine-grained muddy sands that surrounded the bitumen-producing deposits created a permeability barrier common to both models. Duvernay noted that there was no evidence to date of a shale barrier between the channel and the interdistributary deposits, but it believed that the discrete sand beds within the interdistributary facies would be discontinuous and that the very viscous bitumen within this facies would be an effective permeability barrier.

As evidence for the presence of a permeability barrier surrounding the bitumen-producing reservoir, Duvernay stated that it had drilled a horizontal well in LSD 11-20-81-15W5M (11-20 well), the heel of which had been inadvertently positioned within the interdistributary facies before penetrating 1050 m or so of the adjacent reservoir channel. Duvernay reported that this well produced only the water from the interdistributary sands and that this water production overwhelmed any chance of bitumen production from the channel sands. Duvernay subsequently drilled a horizontal well in LSD 6-20-81-15W5M (6-20 well) positioned completely within the channel sands, which produced bitumen. Duvernay argued that there must be a seal along the boundaries of the channel separating the water of the interdistributary facies from the productive channel sands. Duvernay also noted that the productive 6-20 well supported its conclusion that the transgressive lag was not a continuous, porous, and permeable deposit. Duvernay stated that if the transgressive lag had been continuous and permeable, it would have connected the water-bearing sands beyond the channel with the bitumen-producing sands within the channel, and the channel wells would produce only water and not bitumen.

Duvernay noted that reservoir separation also existed within the bitumen-producing channel system. Duvernay referred to Murphy’s 2005 application to amend its primary recovery scheme, wherein Murphy interpreted compartmentalization within its barrier bar reservoir, caused by faulting and permeability barriers, as evidenced by the varying gas, bitumen, and water contacts in wells in the eastern part of the barrier bar.

Duvernay believed that the very viscous bitumen in the interdistributary deposits and the low-viscosity bitumen within the channel facies also indicated reservoir separation. It was Duvernay’s opinion that a fully interconnected system should have predictable viscosity trends within the bitumen column, which was not evident between the interdistributary facies and the adjacent channel facies.

Duvernay noted the complex structure in the Seal Area and believed this to be the result of multiple causes: the erratic topography on the Mississippian erosional surface, the differential compaction over the channel versus the interdistributary deposits, and major block faulting within the Peace River Arch. From its seismic data, Duvernay interpreted a significant structural low to exist separating the A Pool from the productive bitumen channel to the east and another structural low to exist separating the A Pool from the gas accumulation at the 14-27 well to the west.

Duvernay interpreted a fault to be present between the A Pool and Murphy's proposed bitumen project to the north. Duvernay referred to Murphy's 2005 application to amend its primary recovery scheme, in which Murphy identified the presence of east/west trending faults within the bitumen-producing channel. Duvernay projected these faults to continue into the area of the A Pool. Duvernay also noted that the Hubbard et al.[3] paper interpreted faulting to be present just to the north of the subject area, and Duvernay expected the faulting to continue into its lands. Duvernay also stated that its 3-D seismic data to the south confirmed the presence of east-west trending faults.

Duvernay believed that the faults were sealing faults. Duvernay suggested that faulting would create both friction and associated heat, which could result in the formation of pyrobitumen along the fault plane, which would act as a seal. Duvernay further stated that if there were faulting in unconsolidated sediments, the abundant clay within an unconsolidated muddy facies could also act to seal the fault. Duvernay noted that the faults in the area were deep seated and that channels often followed along pre-existing fault patterns.

Pressure Data

Duvernay disagreed with Murphy that there were limited pressure data for the area of interest. It noted that although 30 per cent of the gas reserves had been produced from the A Pool, there had been no impact on wells outside the gas pool. Duvernay referred to six pressure measurements taken on the A Pool—four for the 8-24 well and two for the 1-25 well (including the wellhead pressure accompanied by a fluid level measurement obtained on July 25, 2007)—plus a drillstem test (DST) pressure taken at the well located at LSD 9-8-82-15W5M (9-8 well) to the southeast of the A Pool and two pressure measurements taken at the 14-27 well to the west of the A Pool.

Duvernay contended that the following pressure data showed that the A Pool was contained in a compartmentalized pressure system that was discrete from bitumen production:

- The P/Z plot[4] for the A Pool showed a classic linear trend that is characteristic of a well-defined closed reservoir or "tank." The extrapolated OGIP of 175 10^6 m^3 was lower than Duvernay's initial volumetric estimate of 270 10^6 m^3 but was consistent with the volumetric estimate of 182 10^6 m^3 provided by Atlas Energy Ltd. (Atlas) in its February 2006 application to produce gas from the 8-24 well.

- The difference of about 135 kilopascals (kPa) between the initial DST pressures of the high-quality channel sands at the 9-8 well and the muddy interbedded reservoir at the 8-24 well showed that the high-quality channel sands were not in pressure continuity with the A Pool prior to any significant production in the area.

- The lack of a pressure drop at the 14-27 well despite significant gas production at the 8-24 well showed there was no communication between the two gas pools, which were less than

[3] S. M. Hubbard, S. G. Pemberton, E. A. Howard, "Regional Geology and Sedimentology of the Basal Cretaceous Peace River Oil Sands Deposit, North-central Alberta," *Bulletin of Canadian Petroleum Geology*, Vol. 47, No. 3, September 1999.

[4] A plot of pressure divided by the gas compressibility factor versus cumulative gas production.

1.5 kilometres (km) apart. Duvernay pointed out that 54 10^6 m^3 of gas was produced from the 8-24 well during the period February 2005 to June 2007, during which time the reservoir pressure at the 8-24 well decreased from 4996 to 3485 kPa. The most recent pressure of 4952 kPa measured at the 14-27 well in September 2007 was, within measurement error, identical to the initial pressure of 4956 kPa measured in March 2006. Between March 2006 and September 2007, 24.6 10^6 m^3 of gas was produced from the 8-24 well.

- Duvernay disagreed with Murphy that the pressure buildup shown at the 8-24 well during its recent extended shut-in indicated solution gas was being exsolved from the bitumen and migrating into the A Pool. Duvernay submitted that the pressure buildup was due to the pressure gradient in the pool.

Duvernay acknowledged that the higher water saturations in the bitumen zone suggested the water was mobile. However, Duvernay stated that pressure transmission through the high water saturation in the bitumen zone would be limited because of a discontinuity in the reservoir, although Duvernay did not know what the discontinuity was.

Duvernay argued that Murphy's calculation of an ROI was not applicable to the area of interest because there were insufficient data to make such a calculation and the calculation did not account for any bitumen in the system.

Duvernay stated that it was prepared to conduct additional pressure monitoring on a reasonable basis, potentially more than one survey per year, if the Board allowed gas production to continue from the A Pool. Duvernay recognized that an appropriate shut-in time may be required to properly conduct the pressure monitoring.

6.2 Views of Murphy

Murphy stated that it had confirmed and refined its depositional model by examining cores from the Seal Area. According to Murphy, a barrier bar depositional model accounted for the physical biogenic structures observed in core, and there was no evidence of a major channel system or any indication of a competent or continuous stratigraphic barrier between the gas and bitumen, either laterally or vertically.

Vertical Continuity

Murphy stated that no extensive vertical barrier would be expected within a barrier bar/shoreface environment, although discontinuous interbedded mud within the middle to lower shoreface might act as a baffle of varying effectiveness.

Lateral Continuity and Permeability Barriers

Murphy's geological model predicted no abrupt barriers between the muddy interbedded reservoir and the barrier bar sand trends. Murphy observed that the Bluesky in the Seal Area was not channelized and indicated that the abrupt facies changes expected due to incision were unlikely. Given those observations, Murphy believed that both the rich and muddy interbedded reservoirs were laterally continuous through the upper and lower shoreface. Murphy noted a continuum of reservoir quality between the good and poorer reservoir, such that lateral facies boundaries were probably gradational. Murphy believed that the transgressive sand represented a widespread top blanket of stratigraphically unrestricted and continuous reservoir communication over the entire Seal Area.

Murphy agreed that there were probably faults in the area but that they would likely have very limited throw, thereby preserving the sand-on-sand contacts. Murphy argued any faults would therefore not be sealing. It also stated that there was probably local cementation; however, these cemented zones would occur in a nodular form with limited areal extent and consequently would not form permeability barriers. On the basis of these observations, Murphy believed that the entire reservoir in the Seal Area was in lateral hydraulic continuity.

Murphy accepted that the variability of the reservoir could be extreme to the point where the variation in fluid contacts occurred very rapidly, as shown by the 8-24 and 1-25 wells. It stated that the difference in fluid contacts suggested evidence of a fault. However, Murphy noted that pressure data demonstrated that these two wells were in communication. Consequently, any discussion about faults as a demonstration of pool separation was no longer valid. Murphy also did not believe that the complex geologic structure, which included faulting and uplift as well as permeability barriers within the reservoir, explained the varying bitumen degradation. The varying bitumen degradation, according to Murphy, was not a result of reservoir compartmentalization, but the presence of very strong capillary forces that inhibited flow. Murphy stated that it would take a significant pressure differential to move bitumen. It stated that the small gravitational differences between the densities of water and bitumen was insufficient to cause the bitumen to segregate in the manner that would be expected in a fully interconnected system.

Pressure Data

Murphy submitted that there were very limited pressure data for the area of interest, with only a few pressure measurements over an extensive area. Murphy argued that it was difficult to draw conclusions from the P/Z plot, considering the short period of gas production. Nevertheless, Murphy argued that with time there had been inflation in the OGIP estimated by the gas producers from P/Z plots. Murphy noted that in its February 2006 submission, Atlas estimated an OGIP of 156.3 10^6 m^3; in its July 2007 submission, Duvernay estimated 173.3 10^6 m^3; and in its September 2007 submission, Pearl estimated 181.3 10^6 m^3. Murphy argued that this increase in estimated OGIP was due to additional gas reserves contributed by gas exsolution from the bitumen. Murphy also argued that the P/Z plot for the 8-24 well showed upward curvature indicative of solution gas being exsolved from the bitumen and migrating into the A Pool. But Murphy did acknowledge that there was a very small difference in the R-squared values (a statistical measure of how well a regression line approximates the data points) between a curved line (0.92) and a straight line (0.91). Murphy argued that the continued pressure buildup beyond any reasonable estimate of pressure transient effects at the 8-24 well during its recent extended shut-in provided even more compelling evidence of gas exsolution and migration into the A Pool. Murphy contended that the 135 kPa pressure difference between the 8-24 and 9-8 wells was small, considering that the wells were 4 to 5 km apart, and the small pressure difference could not be used to infer separation when the geological evidence gave no reasonable expectation of separation. Murphy also argued that the lack of a pressure drop at the 14-27 well despite gas production from the 8-24 well was due to a combination of distance and reservoir variability between the wells.

Murphy contended that the Seal Area had pervasive mobile water within the bitumen zone, which, along with the fully interconnected system of sand, provided for extensive intraformation pressure communication. Murphy stated that the presence of mobile water was indicated by the high water saturations shown in the core analyses and by the bitumen wells exhibiting water production. Murphy submitted that the ROI extended beyond the edge of the A Pool because of this extensive pressure communication. Murphy referred to an equation for calculation of a radius of investigation or a radius of influence, but without pressure data being available, Murphy relied on the 2 km extended ROI set for Cold Lake in *Decision 2007-056*. On the basis of a comparison of the reservoir parameters for Cold Lake and Peace River, Murphy argued that the extended ROI at Peace River would be larger than that at Cold Lake. Using a minimum extended ROI of 2 km beyond the edge of the A Pool, Murphy argued that the A Pool was connected to the main bitumen trend to the east and to its applied-for expanded primary recovery scheme to the north.

Murphy stated that pressure monitoring in the area of application was important and should include obtaining pressures below and offset from the gas and associated water zones.

6.3 Views of the Board

Vertical Continuity

The Board accepts the views of Duvernay and Murphy that there are no continuous vertical permeability barriers between the gas in the A Pool and the underlying water and bitumen. The Board also accepts that there may be discontinuous interbedded muds that may act as baffles.

Lateral Continuity and Permeability Barriers

The Board finds that neither geological model submitted at this hearing was able to definitely establish the presence or absence of reservoir permeability barriers. Duvernay's geological model allows for complex lithologies and possible permeability barriers to be present between its interdistributary facies and channel deposits; however, the Board finds that there was no direct evidence identifying these barriers. The geologic model submitted by Murphy does not recognize permeability barriers between its seaward foreshore deposits and the landward barrier bar deposits, although the Board recognizes that reservoirs within a barrier bar system can be more complex than was presented at this hearing.

Although faulting in the Peace River Arch area is well recognized, the Board needs to understand what influence any faulting that is likely present in the subject area may have had on reservoir continuity. The Board agrees with Duvernay that there is potential for a fault to be present to separate the A Pool from the bitumen deposits to the north. Structural comparison of the 1-25 well with the 15-25 well, where the Bluesky sand of the 1-25 well is about 13 m above the top of the Bluesky of the 15-25 well, suggests the presence of a fault between the two wells. The gas and the underlying bitumen in the A Pool would therefore be trapped laterally against the Wilrich shales. The Board notes that seismic amplitude maps submitted by both Murphy and Duvernay show the A Pool to be within a structural nose, and the Board agrees with Duvernay that this structure could be the result of block faulting. Faulting has also been documented by Hubbard et al. to be present to the north in Township 83-15W5M and 83-16W5M. The Board expects that faulting would continue south across the township boundary and be present within the subject area.

With respect to the sealing nature of faults in unconsolidated sediment, the Board notes Duvernay's suggestion of potential seals along the fault plane caused by the formation of pyrobitumen and/or migration of clays. Murphy's view was that the faults in this area are not sealing. However, the Board finds that there are structural anomalies and varied fluid contacts between wells within the channel deposit in Township 82-15W5M, which suggest reservoir separation or compartmentalization. Table 1 and Figure 4, a structural cross-section, compare the fluid contacts of three wells in adjacent sections in the channel: LSD 6-21-82-15W5M (6-21 well), LSD 11-28-82-15W5M (11-28 well), and LSD 5-33-82-15W5M (5-33 well). Given the apparent sand-on-sand contacts between these wells, the Board believes the gas cap in the 11-28 well would migrate updip into the structurally higher 5-33 well unless a seal or permeability barrier was present. As there was no other evidence of permeability barriers within the channel deposit presented at the hearing, the Board concludes that faults in this area are likely sealing.

Table 1. Fluid contacts

Unique well identifier	Gas/bitumen contacts subsea (m)	Bitumen/water contacts subsea (m)
AA/06-21-082-15W5M	+63.3	+54.6
00/11-28-082-15W5M	+65.4	+60.5
00/05-33-082-15W5M	No gas cap, bitumen top +75.3	+59
00/06-33-082-15W5M	+74.4	+63.4

The Board believes that a further example of potential reservoir separation is evident from the logs of the well in LSD 6-33-82-15W5M (6-33 well), annotated and submitted by Duvernay (Table 1). This well has a gas/bitumen contact at +74.4 m SS, 11.1 m above that of the 6-21 well, and a bitumen/water contact at +63.4 m SS, the same structural elevation as the gas/bitumen contact of the 6-21 well.

The Board notes that Duvernay interpreted the interbedded muddy facies containing the A Pool to be characterized by discontinuous bitumen sands interbedded with water-bearing sands and that the bitumen therefore is not a continuous deposit, as evidenced by its 11-20 well. However, Murphy believed that the interbedded muddy facies is bitumen bearing throughout and would be in pressure communication with the offsetting channel deposit. The Board finds that neither party provided evidence that convinces the Board to accept either interpretation, and that the water-producing sand encountered by Duvernay's 11-20 well may or may not be indicative of the bitumen potential of the deposits beyond the bitumen-producing channel.

The Board considers that there is little evidence to support Murphy's interpretation of a porous and permeable transgressive sand providing continuous hydraulic communication between the bitumen-producing channel deposit and the interbedded muddy facies of the gas pool.

Pressure Data

The Board considers there to be a reasonable amount of pressure data for the A Pool, considering that six pressure measurements have been taken on a two-well pool over a period of about three and a half years. However, there is a very limited amount of pressure data beyond the A Pool that can be used to determine reservoir continuity and the ROI, with the only data being two pressure measurements at the 14-27 gas well to the west of the A Pool and a DST pressure at the abandoned 9-8 well to the southeast of the A Pool taken prior to bitumen production occurring in the area.

The Board agrees with Duvernay that the P/Z plot for just the 8-24 well shows a good straight-line trend. However, the Board notes that when the data for the 1-25 well are included, there is more scatter in the data points, resulting in a different straight line. The Board observes that this line does not fit the data as well. Consequently, the Board is not convinced that the P/Z plot definitively shows that the A Pool is a well-defined closed reservoir or "tank," as contended by

Duvernay. With respect to Murphy's argument that the three P/Z plots submitted by the gas producers have shown an increase in OGIP over time, indicating that solution gas from the bitumen has migrated into the A Pool, the Board notes that while Pearl's submission was made after Duvernay's submission, Duvernay's P/Z plot included a more recent data point than the data included in Pearl's P/Z plot and the OGIP estimated from Duvernay's P/Z plot is less than that estimated from Pearl's P/Z plot. The Board also notes that the P/Z plots of Duvernay and Pearl include a data point for the 1-25 well that was not available at the time the Atlas P/Z plot was prepared. The pressure of the 1-25 well was higher than the pressure trend of the 8-24 well, which could explain why the OGIP obtained from the Duvernay and Pearl P/Z plots was higher than the OGIP obtained from the Atlas P/Z plot. Therefore, the Board is not convinced that the three P/Z plots referred to by Murphy show an increase in OGIP over time or indicate that solution gas from the bitumen has migrated into the A Pool. The Board finds that Murphy's interpretation of an upward curvature on the P/Z plot for the 8-24 well is rather subtle, considering the small difference in the R-squared values.

Regarding the continued pressure buildup at the 8-24 well during its recent shut-in, the Board finds that it cannot conclude with certainty whether the buildup is due to pressure equalization in the A Pool because of pressure gradients in the pool or as a result of migration of exsolved solution gas into the A Pool. However, the higher pressures measured in the 1-25 well relative to those of the 8-24 well indicate that there is a pressure gradient in the A Pool, which leads the Board to conclude that some of the continued pressure buildup observed at the 8-24 well can be attributed to pressure equalization.

Regarding the 135 kPa difference in the initial pressures obtained from the DSTs for the 8-24 and 9-8 wells, the Board agrees with Murphy that the pressure difference is relatively small, considering the distance between the wells, and that the pressures were obtained from DSTs rather than static gradient tests. Also, even if some reliance were placed on the observed pressure difference, the Board finds that one data point is not sufficient to conclude that there is no reservoir continuity between the A Pool and the entire main bitumen trend to the east. With respect to the 14-27 gas well showing no pressure depletion as a result of gas production from the 8-24 well, the Board finds that this indicates a lack of reservoir continuity between the gas zones and top water zones at the two wells. However, this does not necessarily rule out the possibility of there being pressure communication through the mobile water within the bitumen zone, which could occur over a longer time period.

To summarize the Board's views on the ROI of the A Pool, the Board concludes that the size of the ROI is a function of the following factors:

- the areal extent of the gas in the A Pool,
- the areal extent of any underlying continuous water leg in pressure communication with the gas,
- the extent of pressure communication through a mobile water phase within the underlying and adjacent bitumen interval, and
- post-depositional influences on lateral reservoir continuity.

As noted in Section 5.3, the Board is satisfied that there is good agreement with respect to the areal extent of the eastern and northern boundaries of the A Pool as mapped by both parties.

However, maps or evidence establishing the areal extent of a continuous underlying water zone were not submitted. Nevertheless, even if the water zone was continuous, considering the steeply dipping structure of the A Pool as indicated on the structure maps of both parties, the thin nature of the underlying water zone would result in only a slight increase to the ROI. The Board therefore concludes that underlying water would have limited or no impact on expanding the ROI beyond the A Pool.

The Board notes that both Duvernay and Murphy agreed that there is likely mobile water saturation in the bitumen zone. This presence of mobile water could result in pressure transmission occurring through the bitumen zone, thereby extending the ROI beyond the edge of the A Pool. In the Board’s view, the appropriateness of using an extended ROI, such as the 2 km extended ROI from *Decision 2007-056,* depends on whether there is an interconnected sand system over the extended area. In this regard, the Board believes the balance of data does not support continuity between the A Pool and the channel deposit to the east for the following reasons:

- The A Pool gas appears to be trapped against Wilrich shales to the north potentially by faulting, and the seismic amplitude contour interpretations submitted by both parties show the structural low to continue to the east of the A Pool. The gas and underlying bitumen may be trapped against the Wilrich shales to the east, as well as to the north.

- As agreed to by all parties, the bitumen-producing wells in the channel to the east are within a different lithology than that of the subject gas wells. The Board is not convinced there is any substantive evidence to suggest reservoir continuity between the two lithologies.

- Variations in fluid interfaces of wells in adjacent sections in the channel deposit (as previously described) strongly suggest separate reservoirs within the channel itself. It would normally be expected that the channel would represent the more homogenous reservoir, compared to the interbedded muddy facies, yet it appears to lack reservoir continuity. This raises further doubt as to the potential for reservoir continuity between the channel deposit and the A Pool.

Unlike the situation at Cold Lake, there are no pressure data in the area of interest to confirm that pressure transmission is occurring through the bitumen zone beyond the edge of the A Pool. Taking into account its view that the balance of data does not support the presence of an interconnected sand system over an extended area beyond the edge of the A Pool, the Board concludes that there is not sufficient evidence to justify adopting the 2 km extended ROI used at Cold Lake or any significantly extended ROI. As a result, the Board finds, on a balance of probabilities, that the ROI of the A Pool does not extend to the main bitumen trend to the east or to Murphy’s applied-for expanded primary recovery scheme to the north.

7 POTENTIAL RECOVERABILITY OF THE BITUMEN WITHIN THE REGION OF INFLUENCE

7.1 Views of Duvernay

Duvernay submitted that the A Pool was not associated with any viable Bluesky bitumen resource. It contended that there was an extremely low probability that bitumen would be produced from the shaly, non-homogeneous bitumen-bearing sands interbedded with water-bearing sands that lie beneath the A Pool. Duvernay stated that 100 per cent water production was essentially guaranteed. Duvernay based this assessment on its experience with its horizontal 11-20 well. The well was targeted to produce bitumen from the Bluesky channel, but it also encountered regional Bluesky for 100 m at the heel of the wellbore. An attempt to produce the well resulted in only water production. Duvernay interpreted the water production to originate from the regional Bluesky. On the basis of this experience, it believed that because of the associated water and the thin bitumen accumulation, bitumen could not be economically produced from the regional Bluesky in the area of application.

Duvernay stated that the onus should be on the bitumen producer to demonstrate that the bitumen was commercial to produce and until it had been shown that there was some technology and some productive capability, the bitumen should not be considered as a resource.

Duvernay argued that Murphy’s evidence on the potential recoverability of the bitumen underlying the A Pool was not clear, since Murphy said the bitumen underlying the 1-25 well was producible but it was not sure if the bitumen underlying the 8-24 well was producible. Duvernay also argued that Murphy’s position that the bitumen underlying the A Pool was producible was inconsistent with the development pattern that Murphy had demonstrated in the area. Duvernay pointed out that

- Murphy said it looked for 5 to 10 m of bitumen and might toe into thinner sands, but there was not 5 to 10 m of bitumen under the A Pool;
- Murphy did not include sections 24 and 25-82-16W5M (where the A Pool is located) in its application to expand its primary recovery scheme to the north of the A Pool; and
- Murphy had avoided drilling bitumen wells in the northwest quarter of Township 82-15W5M, where gas pools were present.

Duvernay stated that a well density of one well per section, with seismic data, should be sufficient to be able to identify the higher-quality channels.

7.2 Views of Murphy

Murphy contended that there was recoverable or potentially recoverable bitumen within the ROI of the A Pool, which included the bitumen underlying the A Pool, as well as the bitumen within its extended ROI to the east and north of the A Pool.

Murphy stated that the bitumen resource underlying the A Pool was economic. It noted that the 15-25 well had 5 m of bitumen pay, and it mapped a highly variable but pervasive bitumen resource of 2.5 to 5 m in thickness under the A Pool. Murphy said that it would target 5 m thick zones and toe into thinner zones where they were present. Murphy stated that bitumen zones as thin as 1 m were economically recoverable and cited seven wells that it had drilled in Townships 82-14W5M and 83-15W5M that had bitumen pay thicknesses of 1.5 to 3 m.

Murphy submitted that it was currently producing bitumen from outside the main bitumen trend, as shown by the bitumen being produced from the bayhead delta complex in Townships 82 and 83-14W5M and at the well located in LSD 14-25-84-15W5M. Murphy also noted that its application to expand its primary recovery scheme to include the area just north of the A Pool was outside the main bitumen trend.

Although Murphy had no examples of where it was producing bitumen overlain by top water, it stated that water above or below bitumen did not preclude bitumen production from adjacent areas because of high variations in viscosity over short distances. Murphy provided several examples of where this had occurred. Murphy indicated that it was too early to write off the bitumen underlying the A Pool, when no pervasive water had been mapped by any party and the ability to recover the bitumen had not been fully assessed.

Murphy argued that discounting large areas of bitumen resource based on a well density of one well per section was incorrect because of the variability of the sand and bitumen qualities. It also argued that the risk to resource recovery had to be considered. Murphy emphasized that continued gas production harmed or presented a significant risk to bitumen recovery. Murphy stressed that this harm was irreversible, since there was no practical way to turn dead bitumen into live bitumen. Murphy contended that, conversely, bitumen recovery did not harm gas production.

Murphy also submitted that

- it was producing bitumen from the same area where Pearl was unsuccessful, which showed that the quality of the Bluesky and the bitumen within it was highly variable over short distances;
- it was planning to conduct enhanced bitumen recovery operations in the region, and loss of solution gas might adversely affect enhanced bitumen recovery; and
- CNRL was producing thin bitumen zones overlain by gas in the Pelican Lake Area.

Murphy stated that the gas production at issue was less than one section away from the recoverable bitumen in the main bitumen trend and, as discussed in Section 6.2, Murphy believed that this bitumen was within the ROI of the A Pool.

7.3 Views of the Board

On the basis of the available data in the area, the Board concludes that the bitumen resource within the ROI of the A Pool is poor quality, since it is relatively thin and is in an interbedded muddy facies. Although no bitumen viscosity measurements were made on the bitumen encountered by the 8-24 and 1-25 wells, the Board expects the bitumen may have high viscosity because of the presence of top water. The poor quality of the bitumen resource, combined with the presence of overlying gas and water, suggests that producing the bitumen would be very difficult or unlikely. The Board is not convinced that there are identified examples of bitumen being produced in situations similar to that encountered at the 8-24 and 1-25 wells.

The Board agrees with Murphy that the drilling density in the area of application is low, so the quantity and quality of the bitumen resource are not known with confidence. However, based on the seismic and net bitumen thickness maps provided by both parties, the Board considers the presence of undetected high-quality bitumen within the ROI of the A Pool to be unlikely. The Board recognizes that in determining whether bitumen is potentially recoverable, the Board must consider whether the bitumen is exploitable with reasonably foreseeable technology and economic conditions. It also recognizes that existing projects will develop lesser quality resources as the projects expand. However, considering the evidence provided in this hearing, the Board accepts Duvernay's view that there is a low probability that the bitumen within the ROI of the A Pool is potentially recoverable.

Accordingly, the Board concludes that gas production from the A Pool should be allowed. However, the Board recognizes that this conclusion is based on limited data and hence there is uncertainty regarding the extent of the ROI of the A Pool and the potential recoverability of the bitumen within the ROI. As a result, there may be a need to reassess the appropriateness of gas production from the A Pool if data become available indicating that the ROI of the pool is larger than what the Board currently interprets or that the underlying bitumen is potentially recoverable. If this were to occur, additional pressure data from the 8-24 and 1-25 wells might assist in the reassessment of the appropriateness of continued gas production. The Board therefore requires Pearl and Duvernay to obtain concurrent pressure measurements at the 8-24 and 1-25 wells every six months for a five-year period or as otherwise stipulated by the Board, starting in early 2008. The pressure measurements must be conducted in accordance with *Directive 040,*[5] including the expectation that the pressure measurements are representative of stabilized reservoir pressures. Bottomhole pressure measurements are preferred, and at least one of the two annual pressure measurements must be a bottomhole measurement. If a second bottomhole pressure measurement is not possible because of access problems, a wellhead pressure may be taken, but it must be accompanied by a fluid level measurement. Pearl and Duvernay must submit annual reports (preferably as single combined reports), two months after the second annual pressure measurements are taken, discussing the results of the pressure measurements and the appropriateness of continued gas production from the A Pool. The reports must be submitted to the Board and Murphy.

The Board encourages Murphy to consider installing piezometers at some of its existing wells or at any new wells that it may drill in the vicinity of the application area to gather pressure data that might assist in better understanding the ROI of the A Pool. The Board expects Murphy to continue to assess the potential recoverability of the bitumen within the ROI of the A Pool based on any new wells drilled in the vicinity of the A Pool.

8 NEED FOR A BITUMEN CONSERVATION STRATEGY FOR THE PEACE RIVER OIL SANDS AREA

8.1 Views of Duvernay

Duvernay stated that it was opposed to the Board setting a regional policy for gas production in the area based on the evidence provided at the hearing. Because of the complex geology and the highly variable nature of the bitumen resource, deciding whether gas production should be allowed must be determined on a case-by-case basis, and affected gas producers must be given an opportunity to provide their views.

Duvernay acknowledged that it would not be prudent to produce gas in the main bitumen trend.

[5] *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells,* December 15, 2006.

8.2 Views of Murphy

Murphy stated that the Board should consider implementing a regional conservation policy. Since the issue of grandfathered wells in the Peace River OSA was not as large as it was in the Athabasca OSA, the gas/bitumen issue would be addressed at a relatively early stage. Murphy stated that it expected the issues in the Seal Area to exist elsewhere in the Peace River OSA. Murphy noted that there was agreement between itself and Duvernay that gas production should not be allowed in the main bitumen trend.

Murphy submitted that the Seal Area should not be divided into areas of gas production and no gas production. It also submitted that the Board should not define a lower bitumen thickness limit for considering bitumen to be recoverable.

Murphy stated that more and better pressure data were required, including pressure data from the gas and bitumen zones. The details of requiring additional pressure data could be determined through a consultative process, and the use of resource management reports at Surmont and Chard/Leismer could be applied to Peace River.

8.3 Views of the Board

In *Bulletin 2006-14*, the Board indicated that it would assess the need for a broader bitumen conservation strategy in the Peace River and Cold Lake OSAs based on the findings of the planned hearings. Although the Board has decided not to shut in gas production from the A Pool, which is not in the main bitumen trend, the Board notes that there was agreement between Duvernay and Murphy that gas production should not be allowed in the main bitumen trend. The Board believes that there is a need to assess whether there is gas production occurring in the main bitumen trends throughout the Peace River OSA, and if there is, whether there is a need to curtail the gas production. The specific process that should be used to conduct this assessment should be determined by the Board at a later time.

Dated in Calgary, Alberta, on December 18, 2007.

ALBERTA ENERGY AND UTILITIES BOARD

<original signed by>

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

<original signed by>

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

<original signed by>

C. D. Hill
Acting Board Member

APPENDIX 1 HEARING PARTICIPANTS

Principals and Representatives (Abbreviations used in report)	Witnesses
Duvernay Oil Corp. (Duvernay) P. J. McGovern	D. Loughead, P.Eng. R. Pachovsky, P.Eng. N. W. Stephenson
Murphy Oil Canada, by its Managing Partner, Murphy Oil Company Ltd. (Murphy) R. W. Block, Q.C.	P. Collins, P.Eng., Consultant D. Demick, P.Eng. D. MacLean, P.Eng. M. Ranger, Ph.D., Consultant J. Restoule
Alberta Energy and Utilities Board staff J. P. Mousseau, Board Counsel K. Bieber, P.Geol. G. W. Dilay, P.Eng. B. Law, P.Eng. N. Sitek, P.Geol.	

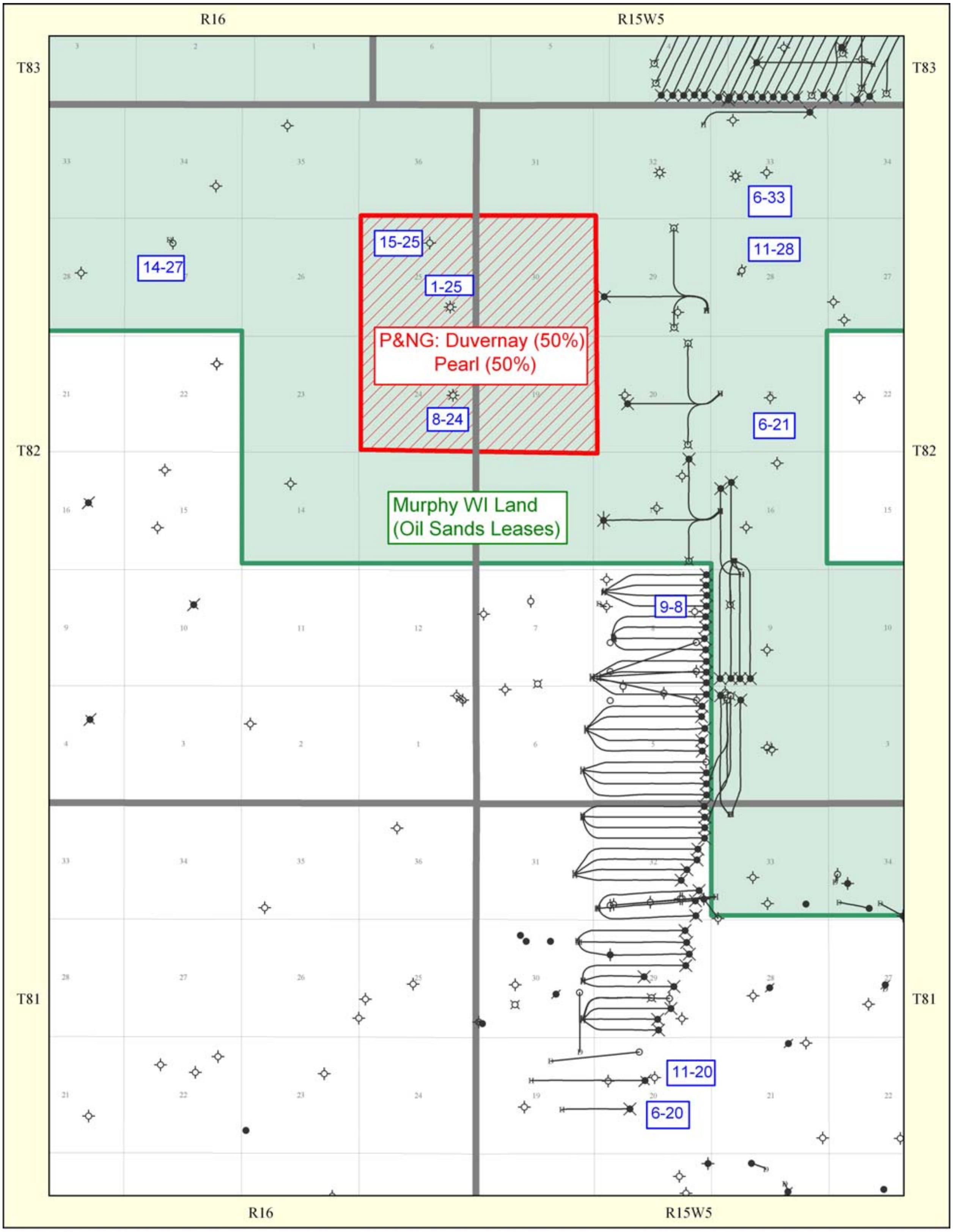
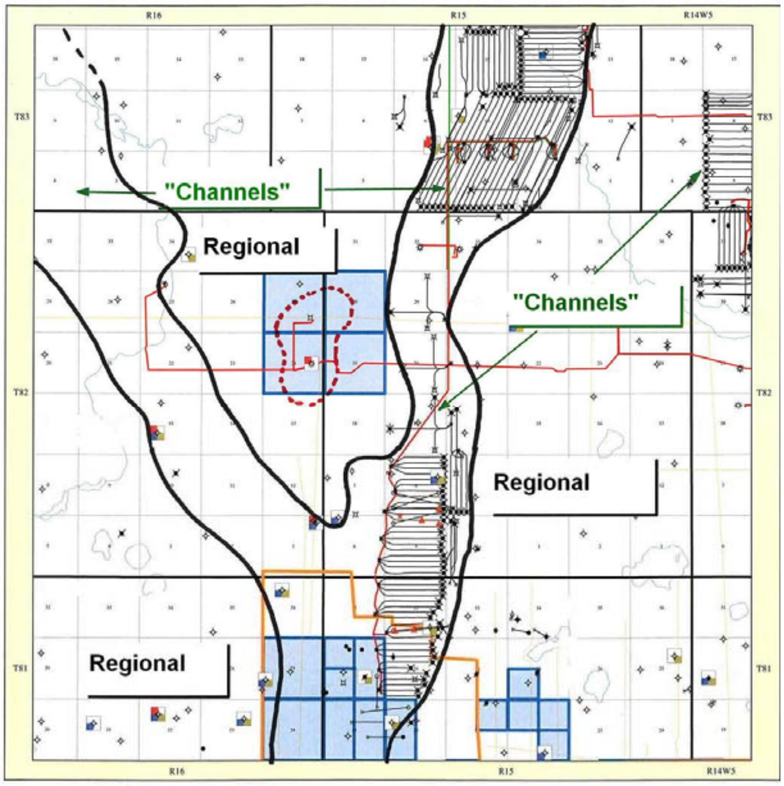
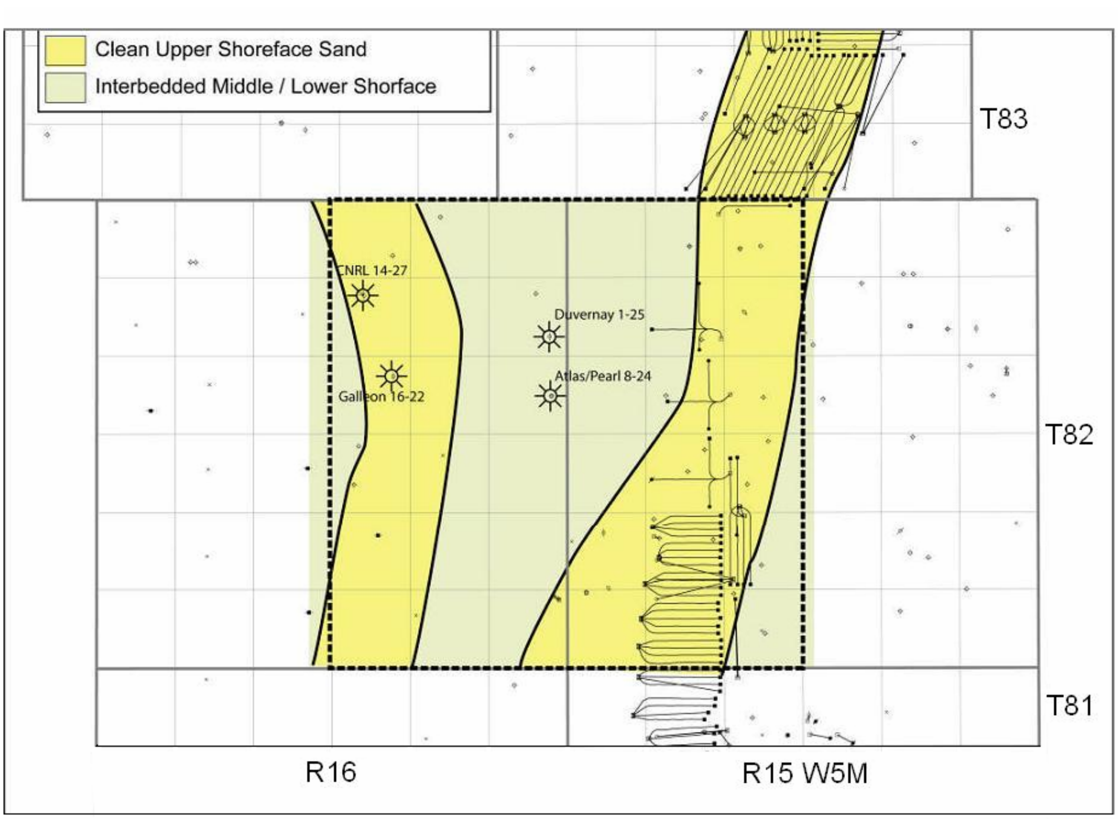


Figure 1. Location map



Duvernay model



Murphy model

Figure 2. Duvernay and Murphy depositional models

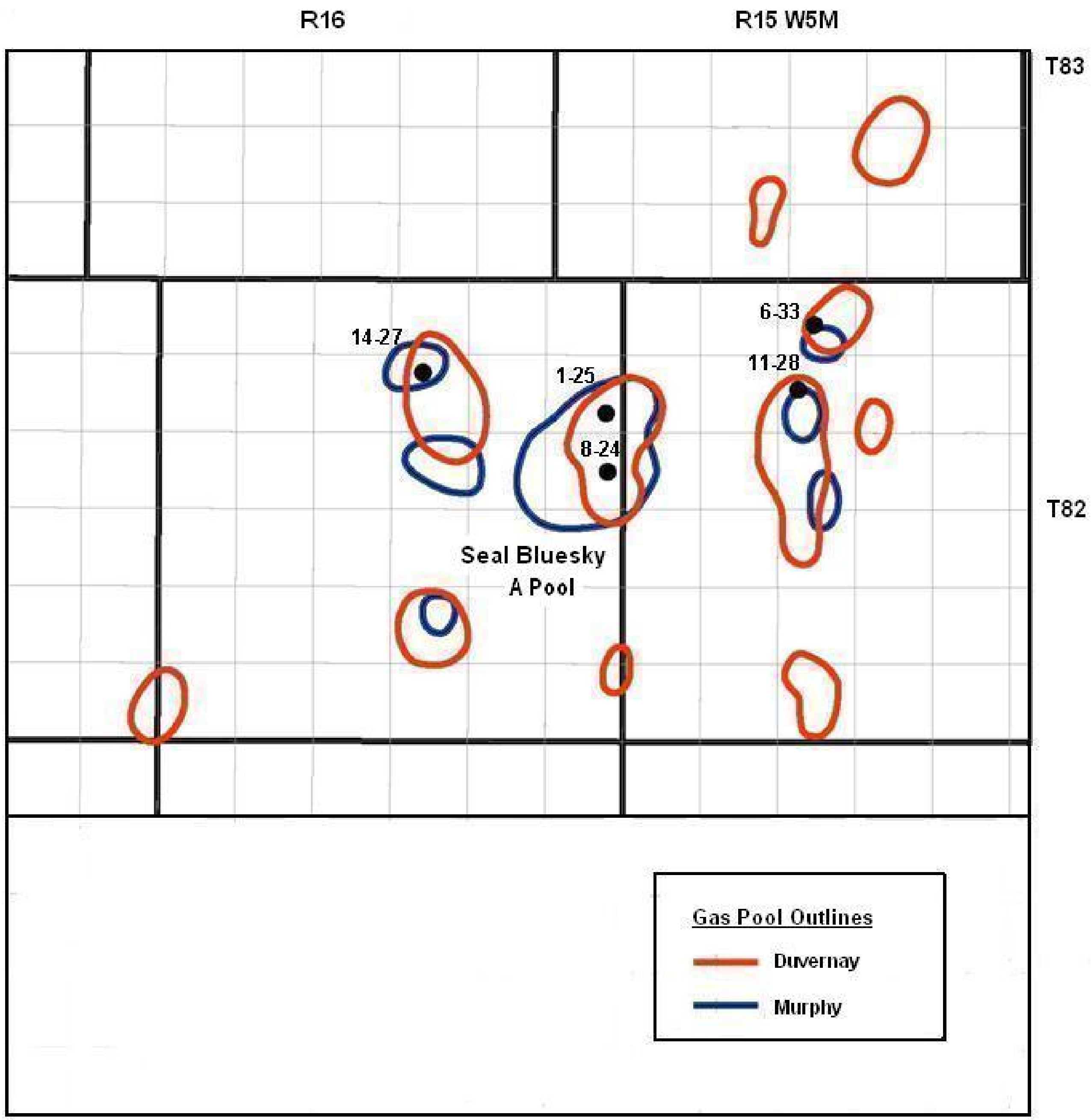


Figure 3. Duvernay and Murphy gas pool outlines

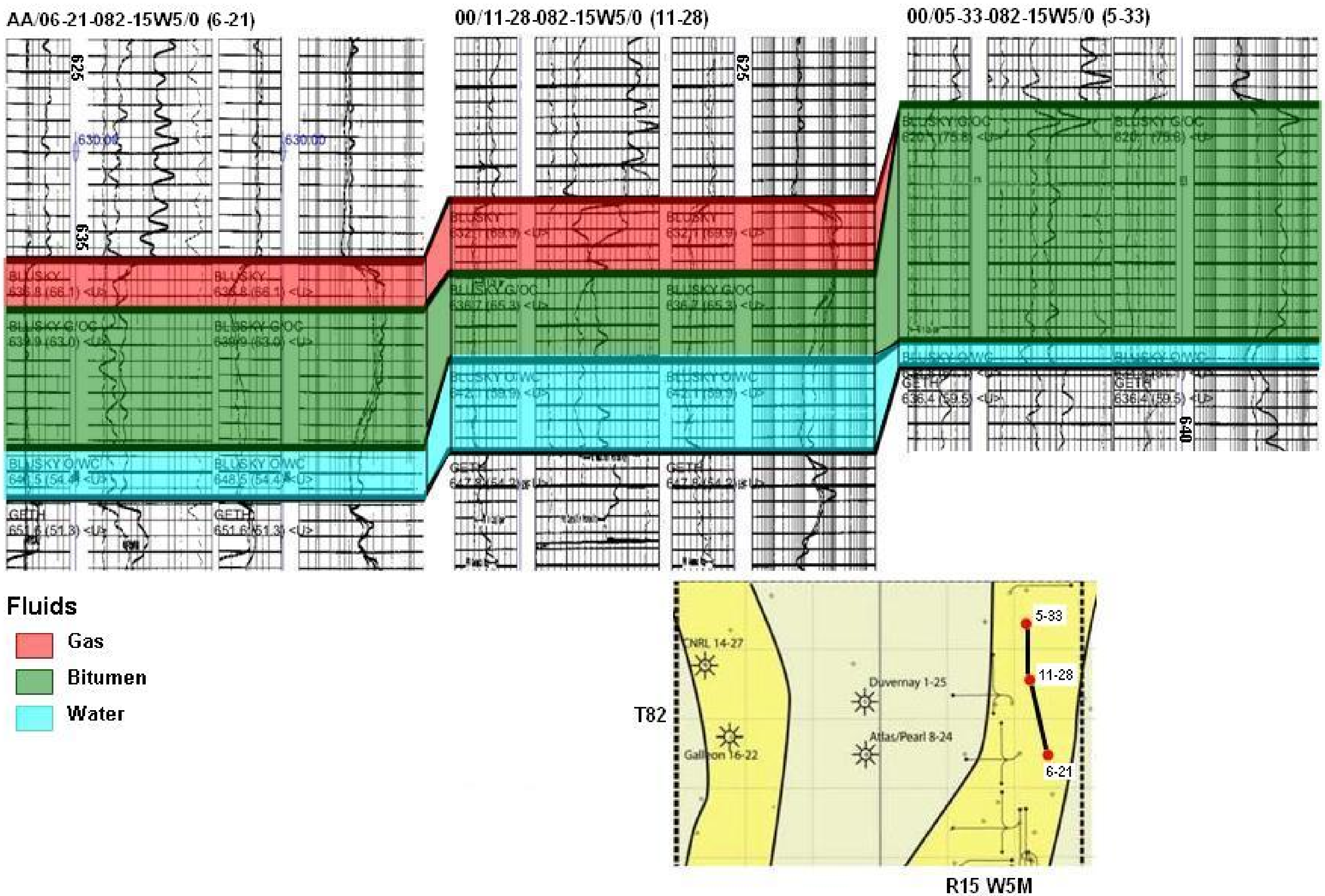


Figure 4. EUB structural cross-section