

ALBERTA ENERGY AND UTILITIES BOARD

**PROCEEDING NO. 1347905
BITUMEN CONSERVATION REQUIREMENTS
ATHABASCA WABISKAW-MCMURRAY
PHASE 3 FINAL PROCEEDING**

**REPLY EVIDENCE OF CANADIAN NATURAL RESOURCES LIMITED
response to the Submissions of February 14, 2005, regarding the production
status of gas wells in Athabasca Wabiskaw-McMurray**

May 9, 2005

Contact for Canadian Natural Resources Limited

Patrick McGovern
Thackray Burgess
1900, 736 - 6th Avenue S.W.
Calgary, Alberta T2P 3T7

Telephone: (403) 531-4728

Fax: (403) 531-4720

E-mail: pmcgovern@thackrayburgess.com

Parties Served

Alberta Energy and Utilities Board

Ernie Smith, Resources Applications
8th Floor
640 – 5 Avenue SW
Calgary Alberta T2P 3G4

Staff Submission Group

J.P. Mousseau, SSG Counsel
Alberta Energy and Utilities Board
640 – 5 Avenue SW
Calgary Alberta T2P 3G4

Interested Parties

CONTENTS

PREAMBLE	4
1.0 INTRODUCTION	5
2.0 KIRBY AREA	
2.1 SSG Submission	
2.1.1 Introduction	6
2.1.2 Kirby Upper Mannville O3O Pool	6
2.1.3 Kirby Upper Mannville I Pool	6
2.1.4 Conclusions	7
2.2 ISH Submission	
2.2.1 Introduction	7
2.2.2 Wabiskaw B Valley Fill Resource	8
2.2.2 Measurement of Net Pay	10
2.2.3 Wabiskaw C Sand	10
2.2.4 Kirby Upper Mannville Pooling Revisions	11
2.2.5 Assessment of Association By Pool	
2.2.5.1 Introduction	13
2.2.5.2 Kirby Upper Mannville J Pool	13
2.2.5.3 Kirby Upper Mannville U2U-Gas Pool	13
2.2.5.4 Kirby Upper Mannville V2V Pool	14
2.2.6 Conclusions	15
3.0 CHARD AND HARDY AREAS	
3.1 Introduction	15
3.2 Petro Canada Submission	
3.2.1 Introduction	16
3.2.2 Conventional Pressure Data Evidence	17
3.2.3 Piezometer Data Cases	18
3.2.4 Geologic Arguments	20
3.2.5 Conclusion	22
3.3 Nexen and SSG	
3.3.1 Introduction	23
3.3.2 Historical Approach	23
3.3.3 Uncertainty in Thickness Determination from Core	25
3.3.4 Other Core Evidence	27
3.3.5 Wabiskaw D Shale Thickness from Logs and Core	27
3.3.6 Wells requested for shut in by Nexen	28
3.3.7 Wells requested shut in by the SSG	29
3.3.8 Conclusion	30
4.0 DUNCAN, LEISMER, THORNBURY AREA	30
5.0 CONCLUSIONS	31

LIST OF FIGURES

- Figure 1. Isopach Wabiskaw C Sand Map
- Figure 2. Wabiskaw B Valley Fill Proposed Pooling
- Figure 3. Kirby Structural Section 9-34 to 7-3
- Figure 4. Kirby Structural Section 9-34 to 6-35
- Figure 5. CNRL Revised B4B Pool Pressure Plot
- Figure 6 CNRL Revised B4B Pool Pressure Data
- Figure 7 CNRL Revised B4B Pool Production Plot
- Figure 8. CNRL revised U2U Pool Pressure Plot
- Figure 9. CNRL revised U2U Pool Pressure Data
- Figure 10. CNRL revised U2U Pool Production Plot
- Figure 11. RGS Bitumen Evaluation Data for Proposed Pool
- Figure 12. RGS Bitumen Evaluation Data for Proposed Pool
- Figure 13. Kirby Stratigraphic Section 5-31 to 7-36 (RGS)
- Figure 14. Kirby Stratigraphic Section 5-31 to 7-36 (CNRL)
- Figure 15. Top Gas, Proof of Wabiskaw C Seal Capacity, U2U Pool.
- Figure 16. Top Water, Proof of Wabiskaw C Seal Capacity, U2U Pool
- Figure 17. Excerpt Net McMurray Channel Bitumen Pay Map from RGS
- Figure 18. RGS Bitumen Evaluation Data for Proposed Pool
- Figure 19. 10-01-074-08w4 Core Analysis Data
- Figure 20. Wabiskaw/McMurray logs for 10-01-74-8W4
- Figure 21. Chard Structural Section 11-33 to 12-35
- Figure 22. Modified Pressure Plot 10-26-81-7W4
- Figure 23. CNRL Modified Piezometer Plot for 10-14-79-7W4
- Figure 24. Piezometer Pressure Plot 10-14-79-7W4
- Figure 25. Piezometer Pressure Plot 9-24-80-7W4
- Figure 26. Wab D shale Presence / Absence Comparison (Nexen vs. SSG)
- Figure 27. Wab D shale Measured Core Thickness Comparison (Nexen vs. SSG)
- Figure 28. Lost Core in SSG Study
- Figure 29. Excerpt from SSG Appendix 1, Contested Wells & Intervals

PREAMBLE

This evidence has been prepared by or under the supervision of James Waterfield, Geologist and Terry Jocksch, VP Exploitation, whose qualifications are set out in their respective Curriculum Vitae. The purpose of this evidence is to respond to the February 14 submissions of the SSG and industry.

1.0 INTRODUCTION

On February 14, 2005 the Staff Submission Group (SSG) and other parties applied for changes to the current production status of gas wells in Athabasca Wabiskaw-McMurray. CNRL is making this submission to comment on and rebut certain of those submissions. In order to accommodate the variety of areas being responded to, we have arranged this rebuttal by area and submission. For each area, CNRL will present its position on the issue raised by each applicant, and then set out CNRL's arguments pertaining to the wells in dispute.

In the Kirby area, submissions were made by CNRL, ISH, and the SSG. The differences in these submissions primarily involve gas in the Wabiskaw B Valley fill. CNRL and ISH submit that the poor reservoir quality of the zone should be recognized and that the bitumen pay cutoff must be increased to 20m. Using this cutoff and the geology of the area, ISH and CNRL will demonstrate that the Upper Mannville J, U2U and V2V and II pools are not associated with bitumen, and should be allowed to produce. The SSG request that the Upper Mannville O3O pool be shut in, but provides no data to demonstrate the Board's interim ruling on this pool was in error. Similarly the SSG seeks to have 3-21-74-7W4 pooled into the I pool and shut in. Again, the SSG fails to provide any new evidence to show that the Board's interim ruling, made after hearing extensive argument on this issue, is in error. CNRL therefore submits that these requests must be denied.

Petro Canada applies to have the Board shut in 9 wells at Chard. One of these 9 wells is part of the regional Chard Wabiskaw McMurray A pool. Consequently, a shut in of that well will have a much larger impact than is stated. CNRL notes that none of the evidence presented by Petro Canada directly relates to the wells Petro Canada seeks to have shut in. The pressure arguments presented by Petro Canada are incorrect or, at least, inconclusive. Much of the material referred to by Petro Canada has been presented to and considered by the Board in previous hearings. The Board did not find such information compelling at that time and accordingly, CNRL submits it should not be persuasive at this time. Similarly, the geologic arguments presented here are general in nature, have been presented to and considered by the Board in previous hearings and were not persuasive. Accordingly, they should not be persuasive in this proceeding. Finally, CNRL's analysis clearly demonstrates that the data presented does not support a reversal of the Board's previous rulings on the production status of these wells.

Nexen and the SSG seek to have the Wabiskaw D shale removed from consideration as a sealing unit. A decision by this Board that the Wabiskaw D Shale is not an effective seal will impact a large number of wells and reverse previous Board decisions to not shut in particular pools because of the presence of the Wabiskaw D Shale. CNRL demonstrates that the two studies are subjective, inconsistent and contradictory, and thus are insufficient to support such a finding. The past practice of examining the nature of this shale on a pool by pool basis remains the only reasonable and logical approach. CNRL demonstrates that when such a pool by pool evaluation is conducted, the evidence does not support changing the production status of the wells as requested.

2.0 KIRBY AREA

2.1 SSG Submission

2.1.1 Introduction

The SSG's February 14th submission seeks to change this Board's previous rulings involving two pools in the Kirby region: the Kirby Upper Mannville O3O pool, and the Kirby Upper Mannville I pool. In both instances, the SSG relies on the same argument of association that was relied on at the interim hearing and was rejected by the Board. The SSG fails to provide any new information to demonstrate that the Board's interim decision was in error. CNRL, therefore, submits that there is no justification for changing the previous decision of the Board as both the issues and supporting data are the same as was presented at the previous hearing.

2.1.2 Kirby Upper Mannville O3O Pool

At the interim hearing, this pool was recommended for shut in by the SSG on the basis of Case 3 association. The SSG argued that a sealing regional shale was not present in 16-5-74-9W4 and 12-9-74-9W4. CNRL argued that the RGS mapping was in error, and that the shale in question existed in those wells. The Board, after reviewing all of the evidence, ruled that this pool be allowed to produce.

The SSG's latest submission relies on the same argument. The SSG simply disagrees with the previous rulings. The SSG does not provide any new evidence to show that the interim decision (Decision 2004-045) was in error. CNRL, therefore, submits that the SSG's request has no merit, and must be rejected. Consequently, there is no new evidence to justify a reversal of the Board's previous ruling and this pool must retain its current production status.

2.1.3 Kirby Upper Mannville I Pool

The second pool on which the SSG seeks to challenge the interim ruling is the Kirby Upper Mannville I Pool. The SSG again applies to have the 3-21-74-7W4, operated by CNRL, placed in the I pool. In the interim hearing, the SSG placed 3-21-74-7W4 into the I pool, and recommended it be shut in. CNRL there demonstrated that this well is a single well pool which is isolated from bitumen, and which should be allowed to produce. The pooling of this well was argued extensively on the basis of pressure data, fluid contacts, and geology. After hearing and considering such argument, the Board ruled that this well was not a part of the I pool, and should be allowed to produce.

The current SSG submission argues that the 3-21 well has a gas water contact similar to those of 12-36-74-7W4, 7-1-75-7W4, and 11-5-75-6W4. The SSG further states that the initial pressure of this well was depleted, and that such depletion supports its view. These

arguments were made in great detail at the interim hearing where CNRL, on the basis of fluid contacts, demonstrated that the 3-21 was not in fact part of the I pool. It is also important to point out that using common fluid contacts to pool wells more than 3, 4 and 6 miles from 3-21 greatly exceeds the pooling criteria of the RGS:

- *Gas was present in the same stratigraphic interval.*
- *Gas/water interfaces were within ± 1 m.*
- ***Wells were in adjacent sections.***

(RGS Pg.75)

At the interim hearing, CNRL also demonstrated that the recorded initial pressure at 3-21 was not depleted. Once again, the SSG requests a change to the previous ruling simply because it disagrees with that ruling, but fails to provide any new evidence to show that the previous ruling is incorrect. Accordingly, the Board again has no justification to alter its previous ruling and the request of the SSG must again be rejected. The production status of 3-21-74-7W4 must be left unchanged.

2.1.4 Conclusions

The SSG applies to have the production status of the O3O pool, and the 3-21-74-7W4 determined at the interim hearing overturned but fails to provide any new evidence to justify its position. Accordingly, CNRL submits that the Board must deny the SSG's request.

2.2 ISH Submission

2.2.1 Introduction

CNRL, ISH Energy Ltd, and the SSG have all made submissions concerning wells in the Kirby area. CNRL and ISH apply to change the production status of a number of pools in this area on the basis of two arguments that were not directly made or addressed at the interim hearing. The primary argument in support of the change in production status is that the ID-99-1 cutoffs are inappropriate for the Wabiskaw B Valley fill. Both CNRL and ISH have submitted evidence which proves the Wabiskaw B Valley fill bitumen resource is inferior. Both CNRL and ISH also rely on Tar – Ells as a precedent where, on the basis of the evidence showing the quality of that resource, the Board increased the cutoff to 15m.

The second argument in this area is that the Wabiskaw C Sand is a regional seal. In the Kirby area the basal interval of this unit is a regionally mappable mud which isolates the overlying Wabiskaw B Valley fill from the underlying McMurray section. ISH Energy provides compelling evidence that this mud is, in fact, a seal, and this seal must also be considered when determining whether bitumen is in association with gas.

In the following sections CNRL will briefly comment on the evidence of ISH regarding these key points. CNRL will then discuss the suggested repooling of wells by ISH, and outline some further modifications to the proposed pooling based on the data. Finally, CNRL will summarize its view of the data presented and on what the production status of several pools should be.

2.2.2 Wabiskaw B Valley Fill Resource

The production status of pools has been determined on the basis of whether gas is in association with potentially recoverable bitumen. This in turn rests on the definition of what is commercially recoverable bitumen. The initial cut-off for potentially recoverable bitumen was 10m of thickness and 50% saturation in the Wabiskaw – McMurray strata. In decision 2004-045, the Board ruled that where the evidence shows the potential for commercial projects may be reduced due to the nature of the reservoir, the 10m thickness criteria should be increased. This was the case at Tar - Ells where the cutoff was increased to 15m.

In its February 14 submission CNRL argued that the Board was incorrect when it concluded that:

“Wabiskaw sands in southern portions of the study area (Kirby Field): may be valley fill in nature and are thus more similar to the McMurray in their depositional setting” (Decision 2004-045, Pg. 5).

CNRL submitted that the Wabiskaw B Valley fill sands are fundamentally different from the McMurray, and that these differences result in the Wabiskaw resource being significantly poorer than the McMurray. CNRL presented data which demonstrates the depositional differences between the McMurray and Wabiskaw. CNRL has also presented the petrological analysis carried out by AOSTRA that further highlights the differences in the two formations. Thirdly, CNRL used core analysis data to conclusively show the differences between the two formations. Finally, CNRL showed that these differences would dramatically reduce the performance of SAGD.

In the ISH Energy submission of Feb 14, a similar conclusion was reached concerning the resource quality of the Wabiskaw B Valley fill. ISH Energy finds that the Wabiskaw B (in stark contrast to the fluvial estuarine McMurray) is a sharp based shoreline succession deposited in a fully marine environment. This is confirmed through a comprehensive core study. ISH notes an absence of sedimentary structures indicative of high energy (upper) flow regime, which would be expected in a marginal fluvial estuary. Trough cross bedding, IHS, tidal bundles and paired mud couplets; all abundant in McMurray sediments, were absent in the Wabiskaw B. Also, wave formed ripples were found to be the most common sedimentary structures. This lack of similarity between the two reservoirs demonstrates that these formations were not deposited in the same environment.

Ichnological examination of the core by ISH Energy supports their conclusion:

“Cruziana, in particular Rhizocorallium, Terebellina, Zoophycos and Asterosoma, in addition to Bergaueria from the Skolithos association indicate fully open marine deposition” (ISH submission Feb 14, Pg 36)

McMurray ichnology, or that of estuarine deposits contain mostly monotypic assemblages, often of cylindrichnus associated with IHS deposited in a variable brackish to fresh water environment. While a fluvial estuary may at times display salinities similar to open marine conditions, the constant variability creates an entirely different depositional assemblage from a marine system. The data presented by ISH proves that the Wabiskaw is clearly not similar to the McMurray in depositional setting.

CNRL demonstrated through core analysis and the work of AOSTRA (Report #10) that the Wabiskaw B Valley fill is a significantly poorer resource than the McMurray at Kirby. The ISH submission demonstrated that this resource is also inferior to that of the Wabiskaw at Tar – Ells. Petrographic studies reported by ISH reveal that the Wabiskaw in the Kirby area is composed of a consistently finer grain size with higher volumes of kaolinite cement when compared to the Wabiskaw further north. ISH also reports that diagenetic clays within the Wabiskaw B are responsible for reducing effective porosity in the reservoir by 30 – 40%.

CNRL submitted theoretical SAGD performance calculations for the Wabiskaw B which show that the low saturations combined with lower permeability in a thin reservoir greatly impede the effectiveness of the process. Even at 15m, the performance of SAGD in the Wabiskaw is poorer than in 10m of McMurray reservoir. These calculations do not however take into account many of the other detrimental features of the Wabiskaw B Valley fill. Both ISH and the AOSTRA reports identify clays susceptible to migration or swelling when exposed to fresh water (steam) inputs. Both ISH and CNRL recognize cemented intervals in the Wabiskaw B which are aerially extensive, and have a high potential to interfere with SAGD operation. ISH notes that the Wabiskaw B consists of more than 50% mudstones in the area of the Upper Mannville II pool. These mudstones are thin, however they are laterally continuous, and would pose a serious challenge to thermal extraction methods. These features combined with the Wabiskaw B’s coarsening up pattern, which places the wells in the poorest reservoir, result in a very problematic resource. If all these additional features are considered, the closer approximation to 10m of McMurray would be 20m of Wabiskaw. The challenges of producing this zone are evident in the performance of a Cyclic Steam Stimulation (CSS) pilot project operated in Section 29-073-07W4. That pilot project was unable to achieve commercial recoveries despite using a process that can overcome reservoir barriers by fracturing the zone.

The findings of ISH Energy mirror those of CNRL. The dissimilar depositional environment in the Wabiskaw B Valley fill has produced a different and inferior reservoir for bitumen development.

Further analysis involving comparison of the Kirby Wabiskaw to the Wabiskaw at Tar-Ells reveals that they are diagenetically similar, yet the Kirby reservoir is in fact inferior to that at Tar – Ells. This too suggests that the 10m of McMurray equivalent for the Kirby Wabiskaw must be more than the 15m cutoff applied at Tar – Ells. Clearly the Wabiskaw resource at Kirby is less amenable to commercial production. This must be reflected in the cutoffs applied.

In summary, the lithology including sedimentary structures, grain size, composition, ichnology, bitumen saturation and clay mineralogy, all indicate that the Wabiskaw B Valley Fill in the Kirby region is fundamentally a different and poorer reservoir than the McMurray Formation below. Independent research submitted by both CNRL and ISH verify these differences and are demonstrate that the Wabiskaw at Kirby is poorer than the Wabiskaw resource at Tar – Ells. It is clear from this that, for the purposes of establishing a meaningful cutoff, the Wabiskaw B Valley Fill should not be governed by the same cutoffs for potentially recoverable bitumen as the McMurray Formation. CNRL agrees with ISH and believes that cutoffs applied to this unit should be raised. The data submitted indicates that the 15m invoked in decision 2004-045 at Tar-Ells is too low, and that 20m is more appropriate.

2.2.2 Measurement of Net Pay

Once the Board has established what the appropriate thickness cutoff should be, it must then examine the bitumen thicknesses within each pools area of influence. As demonstrated in its submission of Feb 14th, the methodologies used in the RGS to determine bitumen pay greatly overstate the actual pay. CNRL presented a number of potential flaws in the methodology which may contribute to this problem. Whatever the cause however, the Board must recognize this overstatement when examining bitumen pay data from the Wabiskaw B Valley fill. Both CNRL and ISH have also noted the apparently regionally continuous cemented streaks that are nearly universal in the Wabiskaw B Valley fill strata. The RGS data assumes these zones do not isolate reservoir above and below them. This assumption is unproven, and appears contrary to the evidence from logs. In summary, the submissions of both ISH and CNRL show that the RGS reported pays are overstated, and may group discontinuous intervals. The facts must be recognized in the Boards examinations of pools.

2.2.3 Wabiskaw C Sand

The second key to determining association is the identification of effective barriers to pressure communication. The Board has recognized three to date; the McMurray B Mudstone, the McMurray A Mudstone, and in some instances the Wabiskaw D Shale. In its February 14 submission CNRL submitted that isolation of the Wabiskaw B Valley Fill from underlying McMurray Sediments may further be supported by examination of the basal portion of the Wabiskaw C Sand. Although called “sand” by naming convention, only the lowermost portion of the Wabiskaw C unit is present in this area. The log

character in the Kirby region, suggests that this basal portion of the unit is primarily mud (CNRL Feb 14, Pg. 16). CNRL stated that it is sufficiently thick, widespread and of such poor quality that pressure communication across it is highly unlikely.

ISH Energy has proven this conclusion. In its February 14 submission ISH presents core evidence from well 100/14-18-075-08W4 showing a top water/gas interval trapped below the muddy basal portion of a cleaning upward cycle which underlies the Wabiskaw B Valley fill. This upward coarsening unit is certainly the Wabiskaw C. ISH shows that this top water / gas zone can be recognized on logs in the adjacent 1-11-75-9W4 and 1-13-75-9W4. For preservation and occurrence of top water / gas, the overlying unit must be a sealing cap rock. This unit is identical to that mapped by the RGS as continuous over much of the Kirby area (Figure 1).

ISH maps numerous other instances of top water or gas trapped below this same interval (ISH Feb 4 submission, Appendix 2, Fig. 3 & 4). As an areally extensive unit which has been repeatedly demonstrated to be a pressure seal, the Wabiskaw C must be considered when assessing communication.

2.2.4 Kirby Upper Mannville Pooling Revisions

For its February 14, 2005 submission, CNRL examined problem wells within the Upper Mannville B4B and J Pools and based its submission on that examination. CNRL showed that well 00/11-25-073-08W4 should not be included in the Upper Mannville J-Gas Pool on the basis of fluid contacts. The submission of ISH Energy (February 14, 2005), went further and suggested additional re-pooling. In response, CNRL undertook a more comprehensive review of pooling at Kirby. CNRL found that pressure data does not provide unique solutions. As a result, CNRL's evaluation was based primarily on fluid contacts of adjacent wells, with pressure data used to test potential pooling. As in the RGS, a gas / water contact tolerance of + or - 1m was utilized. The following paragraphs will outline our conclusions and relate them to the February 14th submissions of both CNRL and ISH.

ISH Energy states in its submission of evidence dated February 14, 2005:

“Our study shows that the 00/11-25 well is separate from the Upper Mannville J Pool, negating any communication with the McMurray zone below due to the presence of the sealing mudstones throughout the entire pool.”

This conclusion is in agreement with the submission of CNRL. ISH Energy also states that:

“The 00/11-25 well has been pooled with the wells in the Upper Mannville B4B Pool, along with the wells in 35 and 36-073-08W4”.

CNRL has examined this proposal and is in partial agreement with the proposed pool modifications. CNRL agrees that the fluid contact data suggests 11-25-73-8W4 belongs with many of the wells suggested by ISH. An examination of the entire area, however, shows that further modification of pooling is required to honor all the data. Figure 2 illustrates CNRL's proposed pooling. CNRL is in agreement with ISH that gas water contacts in 11-25-73-8W4 are consistent with those of AA/5-36-73-8W4, AA and 102/6-35-73-8W4, as well as 7-3-74-8W4. The adjacent 100/11-3-74-8W4 remains pooled with 7-3 as its gas contact is consistent with this pooling. CNRL also finds that as ISH suggests, 7-36-73-8W4 does not belong in the Kirby Upper Mannville V2V pool as its gas zone occurs down dip of water. The fluid contact is however consistent with the gas water contacts of 5-36, 6-35, and 7-3. CNRL suggests this new pooling retain the Upper Mannville B4B designation.

CNRL, however, finds that the fluid contacts from the wells in section 34-73-8W4 are not consistent with this grouping. Figure 3 illustrates this problem. The base of gas in 100/9-34-73-8W4 (238.8m asl) is 1.7m below the top of water in the adjacent 02/7-3-74-8W4 (240.5m asl). Similarly, the base of gas is 2.2m below the top of water in 02/6-35-74-8W4 (241.0m asl) (Figure 4). Based on this the wells in section 34 have been removed from the B4B pool (Figure 2). Pressure data and depletion history for the revised B4B pool (11-25, 6-35, 5-36, 7-36-73-8W4, 7-3 and 11-3-74-8W4) indicate this pooling is reasonable (Figures 5, 6 and 7).

Pressure data from wells in section 34 show depletion prior to initial production from the section. From this it must be concluded that these cannot be a pool in isolation. The most reasonable connection is to link these wells to the adjacent U2U pool. The fluid contact data matches through this connection, and the pressure depletion history is also a good fit (Figures 8, 9 and 10).

ISH submits that 100/12-16-074-07W4 (00/12-16) should not be included in the Upper Mannville V2V Pool. CNRL agrees, but wishes to clarify the contacts discussed in ISH's submission. ISH has stated that the 00/12-16 well has a gas / water contact at 245.0m subsea. CNRL notes that the gas / water contact is in fact located at 255.8m asl. This correction now places the water pool at 12.7m above the base of gas in 00/10-18-074-07W4 (found at 243.1m asl). This is clearly a separate pool.

Based on the analysis described above, CNRL concludes that the original poolings for Kirby proposed in the RGS are in error. Because the available pressure data does not provide conclusive well groupings, pooling must be based primarily on fluid contacts, with pressure data used to supplement this information. CNRL finds that the poolings depicted in Figure 2 honor all the available data, and should form the basis for the Boards evaluation of association.

2.2.5 Assessment of Association By Pool

2.2.5.1 Introduction

In the previous sections CNRL has described its proposed poolings at Kirby, and the basis on which those poolings were made. ISH and CNRL have each made a compelling case to increase the bitumen cutoff for the Wabiskaw to at least 15m. CNRL submits that when both sets of data are examined it is apparent that a 20m cutoff is more appropriate. In the following sections the production status of pools for which CNRL seeks a change in the production status will be covered using the poolings and criteria discussed.

2.2.5.2 Kirby Upper Mannville J Pool

The Kirby Upper Mannville J-Gas Pool is currently shut in on the basis of Case 3 and Case 4 association. As presented in the February 14th submission of CNRL, 11-25-73-8W4 must be removed from the pool on the basis of fluid contacts. Having done so, the revised pool is entirely isolated from McMurray bitumen by the regional McMurray shales. Thus, Case 3 is no longer valid (Figure 2).

None of the wells in this pool approach the proposed 20m cutoff for Wabiskaw bitumen. As presented in CNRL's February 14th submission, only 3 wells are reported to exceed 15m of bitumen (Figure 11). Also as documented, the RGS bitumen pay analysis greatly overstates actual pay by between 8% and 281%. If, as was shown in the submission, this is taken into account, none of these 3 even exceed 15m. Thus, case 4 is also not valid. A more complete discussion of this is presented in CNRL's February 14 submission. If Case 3 and Case 4 association do not apply, the Board must change the production status of this pool to produce.

2.2.5.3 Kirby Upper Mannville U2U-Gas Pool

At the time of submission, the Upper Mannville U2U-Gas Pool was shut in under Case 3 and Case 4 association with bitumen. Under the revised pooling outlined previously, none of the wells in this pool exceed 15m of bitumen, well below the 20 cutoff proposed for Wabiskaw bitumen pay (Figure 12). Thus Case 4 does not apply.

As shown in Figure 2, the bulk of the wells in the U2U pool are underlain by regional McMurray shales. Although there also appear to be a number of wells in which these regional shales are absent, the RGS mapping contain numerous errors. The 9-34-73-8W4 well is depicted as having no McMurray shale seal. In CNRL's February 14 submission, this was shown to be a mapping error, and that the McMurray sealing shale was in fact present. Similarly, as stated in the submission of ISH, a mapping error in the RGS is responsible for the depicted absence of McMurray shales in 10-2-74-9W4 and 9-3-74-9W4. It should also be noted that although 14-31-73-8W4 is depicted as not having the

McMurray shale, the well does not penetrate deep enough to reach the McMurray. The other well in section 31 does in fact have the McMurray shale.

Figure 13 is a two well stratigraphic cross section between 5-31-73-8W4, in which the RGS recognized the McMurray A2, and 7-36-73-9W4 where it does not. CNRL believes the depositional pattern in both these wells is identical, and that the corrected correlations (Figure 14) prove this. An exact duplicate of the McMurray A2 coarsening upward sequence in 5-31 can be seen at precisely the same stratigraphic elevation in 7-36. The abrupt erosional transition to the overlying sands of the Wabiskaw D valley fill that is seen in 5-31 is again exactly replicated in 7-36. The Gamma Ray low and the Neutron Density separation that marks the Wabiskaw C in 5-31 is also replicated in 7-36. Clearly these features are not a coincidence. The regional McMurray shale mapped in 5-31-73-8W4 is present in 7-36-73-9W4. Thus, the only wells lacking the regional McMurray seal are those located in sections 5 and 6-74-8W4.

As shown in Figure 1, this area is however entirely underlain by the Wabiskaw C sand, the basal portion of which ISH has shown to be a pressure seal. The sealing nature of this unit is illustrated by the trapping of gas below it in 100/10-34-73-8W4 (Figure 15) and top water in 100-9-34-73-8W4 (Figure 16). The regional cemented streaks and high mud content of the Wabiskaw, serve to further isolate this gas pool from the McMurray. It is important to also note that despite the number of wells drilled in this area, the mapping of the RGS depicts little to no bitumen in the McMurray (Figure 17). Based on this combination of multiple barriers and minimal bitumen, CNRL believes that the absence of the McMurray shales does not put potentially recoverable bitumen at risk. As the remainder of the pool has these features, plus the McMurray shales, this pool is not in association with McMurray bitumen. Since neither Case 3 nor 4 apply, CNRL agrees with ISH and submits that this pool should be allowed to produce.

2.2.5.4 Kirby Upper Mannville V2V Pool

This pool was shut in under association cases 3 and 4. With the revised pooling, the RGS bitumen assessment (Figure 18) shows no wells approach the proposed 20m cutoff, and only 2 wells which exceed 15m. The first well, 2-11-74-8W4 has a nominal pay thickness of 15.5m. If this exaggerated value is corrected by 8%, the smallest amount of RGS overestimation documented by CNRL, the true bitumen pay would also fall below 15m. The well at 10-01-74-8W4 is shown in the RGS data to contain 17.79m of pay. This well is yet another example of overstatement of pay by the RGS. The well was cored through the entire Wabiskaw B Valley fill. Of the 19m of zone cut 16.35m was recovered. This material contains 13.68m of sand with a bitumen saturation greater than 50% (Figure 19). Of the 2.65m of lost core, 0.55m corresponds with a cemented streak on logs (Figure 20, 499.5-500.5m) If all of the remaining lost core (2.1m) is assumed to be pay, the maximum total pay in this well cannot exceed 15.78m. Thus the RGS overstates the pay by nearly 13%.

Even under the originally proposed 15m cutoff CNRL believes this well is an insufficient basis to shut in the pool. The definition for potentially recoverable bitumen states:

“Consideration must be given to the volume of the bitumen encountered, the geological depositional environment, the presence of associated water zones, and the available well control”

The V2V pool is large in extent in comparison to this single bitumen well. CNRL believes that if proper consideration is given to the poor reservoir quality (saturation and permeability), the regional cemented streaks, and the swelling clays, the Board should find that this well represents a small and highly speculative volume of bitumen. In this instance, given the exceptional challenges of the Wabiskaw and that it is a single occurrence, CNRL submits that the bitumen would not warrant protection even under a 15m cutoff. As such, case 4 should not apply.

With respect to the alleged Case 3 association, the pool is entirely underlain by the Wabiskaw C, with the exception of 10-01-74-8W4, where regional McMurray acts as the seal. This unit averages 2m of thickness and has been demonstrated by ISH to be a sealing unit (Figure 1). ISH also notes that a single cemented horizon (Wabiskaw B Cemented Horizon 4) (ISH Feb 14, Pg 26) is continuous throughout the pool, and serves to further isolate the gas. These barriers effectively isolate this pool from the Wabiskaw D Valley fill, and the underlying McMurray. In addition, every well in the pool is isolated from McMurray Bitumen by regional McMurray shales with a single exception 10-13-74-8W4. Due to these multiple barriers, this gas pool is not in association with potentially recoverable bitumen under Case 3. As neither Case 3 nor Case 4 applies, this pool should be allowed to produce.

2.2.6 Conclusions

Both ISH and CNRL have demonstrated that the Wabiskaw B Valley fill resource is inferior to the McMurray, and even to the Wabiskaw at Tar - Ells. Based on the facts presented, CNRL and ISH recommend that the cutoff applied to the resource be increased to at least 15m, and more reasonably 20m. CNRL and ISH have also shown that, once the pools are properly defined by geology and pressure, the Upper Mannville J, B4B, U2U, V2V and II are not associated with potentially recoverable bitumen. As such, the Board should rule these pools able to produce.

3.0 CHARD AND HARDY AREAS

3.1 Introduction

The Chard area has been examined in two previous interim hearings. Petro Canada, Nexen and the SSG have submitted requests to have wells in the area reconsidered. The SSG also requests the shut in of numerous wells in the Hardy area based on the same

evidence as was previously considered by the Board. The Petro Canada submission seeks to have 9 wells (6 CNRL) shut in based on pressure evidence and geology.

CNRL maintains that the pressure evidence is inconclusive and has been argued previously, the geology arguments have also been presented previously, and none of the data directly relates to the wells requested for shut in. As no new evidence has been submitted to show the requested wells are associated with bitumen, the Board should reject this request.

Nexen and the SSG request that the Board rule that the Wabiskaw D shale not be considered a potential seal, and list a number of wells they seek to shut in as a result. The basis for their request is the core studies each have submitted. The use of core can be a very subjective process, and the inconsistent and contradictory findings of Nexen and the SSG prove this. CNRL submits that these flawed studies cannot form the basis for the sweeping ruling requested by Nexen and the SSG. A pool by pool examination is a much more reasonable and logical method of dealing with this issue. When these wells are examined in this manner, the evidence available does not support changing the production status of the wells. CNRL, therefore, submits that the requests for shut in should be denied by the Board

3.2 Petro Canada Submission

3.2.1 Introduction

The February 14 submission of Petro Canada requests the shut in of 9 wells, 6 of which are CNRL operated. Petro Canada seeks to have these wells shut in because “a geologic review and pressure data analysis .. indicates that production from natural gas wells identified for shut in is impacting the potentially recoverable bitumen”(pg.1). CNRL has examined the evidence and finds that the communication suggested in the submission goes against the rulings of the Board at previous Chard hearings, and is not supported by the evidence provided in this proceeding.

CNRL notes that one of the requested wells, 6-22-80-6W4 is designated as part of the very large Chard Wabiskaw McMurray A Pool (78 wells, >1 Township). If this well is found to be associated the entire pool must be shut in. Petro Canada should have made this clear in its submission to allow all those affected a chance to respond.

CNRL contends that there are 3 compelling reasons to reject Petro Canada’s request. Firstly, none of the pressure arguments presented (both conventional and piezometric) support the contention that regional McMurray mudstones are not pressure barriers. Secondly, the geologic material presented is general in nature and has already been repeatedly argued and ruled on by the Board at the previous Chard hearing. No new data is presented which warrants a change to the Boards findings. Thirdly, Petro-Canada provides no direct evidence which indicates that continued production from the 9 specified wells is impacting potentially recoverable bitumen.

In the following sections, CNRL will cover each of the points described above and demonstrate that the data does not support Petro Canada's case. With no new compelling evidence on which the Board could base a reversal of its previous findings, it must reject Petro Canada's request and allow the subject wells to produce.

3.2.2 Conventional Pressure Data Evidence

Petro-Canada presents the 11-33 and 12-35-79-7W4 wells as an example of pressure communication across the regional A2 shale. In their submission they show a gradual pressure decline in 11-33-79-7W4 despite a lack of production. They then examine the nearby wells and conclude that the depletion of the McMurray A2 sand is due to depletion of the gas pools in the McMurray B and C sands in 12-35-79-7W4.

CNRL has examined this case and believes that fluid contact data rules out the connection postulated by Petro-Canada. Figure 21 is a two well structural cross section between the two wells. In 11-33-79-7W4 the gas interval is identified in the RGS as 320.5 – 321.8m Kb. If one examines the interval immediately below this gas (321.8-323.8m Kb) the log characteristics of a top water zone are evident. In this interval the Gamma Ray remains low, indicating sand, the SP curve indicates permeability, the sonic log shows an absence of gas, and the resistivity is significantly lower than the overlying gas zone. This conclusion is supported by a DST (319-323m Kb) which recovered water. Immediately below this top water zone is an interval of low GR (relative to true shales in the well), a suppressed SP, and high resistivity. These are characteristic of a bitumen charged (dirty) sand. Thus, the A2 reservoir in 11-33-79-7W4 consists of a gas over water over bitumen.

As can be clearly seen in the cross section the McMurray B gas in 12-35-79-7W4 is located substantially down dip of 11-33-79-7W4. The base of gas in 12-35 lies approximately 18m below the top of bitumen in 11-33, and the gas water contact in 11-33 is nearly 18m above the top of gas in 12-35. If these two wells were truly in communication through the A2 regional mudstone, 12-35 should be entirely charged with bitumen or water. Clearly, the depletion described in 11-33 cannot reasonably be traced to production from 12-35.

This then begs the question of where the depletion is coming from. A re-examination of the data presented by Petro-Canada reveals a more plausible explanation. The pressure data point taken in 11-33-79-7W4 in March 1999 is a calculated bottom-hole pressure from a surface pressure reading taken during a deliverability test. As the perfs being tested immediately overlie water (Figure. 21) it is likely that some water will have been drawn into the wellbore. This in turn will result in the understatement of downhole calculated pressure when extrapolated from surface readings. CNRL believes this is the case, and that in March 1999 11-33 was still at Virgin pressure. The subsequent depletion recorded February 2002 reflects the offsetting production from 10-36-79-8W4. This well began production in February 1999, and has been depleted to a current pressure of

1400kPaa. This is a far more reasonable explanation as the depletion comes from the same zone, is consistent in timing, distances, and does not involve unreasonable fluid contact relationships. Based on this analysis, CNRL contends this case does not represent an example of pressure communication across regional mudstones.

3.2.3 Piezometer Data Cases

Petro Canada presents 3 case studies based on Piezometer data to support its contention that the McMurray regional mudstones are not effective pressure seals. In each case it points to an apparent decline in pressure over time as indicative of vertical communication through the McMurray. These cases are similar to those presented by Petro Canada at the first interim hearing for the Chard area.

In section 5.3.1 of the Petro-Canada submission the 10-26-81-7W4 case study is presented. It purports to show a pressure rise in a bottom water zone in a McMurray channel through a massive bitumen section in response to the shut in of wells in the Surmont region. This is the same case presented at the first interim hearing at Chard. At that time the Board could not make such a correlation primarily because:

“unlike the other piezometer data entered as evidence, these pressure data were collected at discrete time intervals rather than continuously. Moreover, the pressure appears to begin to rise prior to the shut-in order” (Decision 2003-023 pg. 24).

These issues have not changed and the recent data presented by Petro-Canada actually show the interpretation of this data is more problematic. Contrary to Petro-Canada's assertion, the continuous data demonstrates the piezometer in 10-26 has an error band of approximately 40 kPa (Figure 22). In addition, there is no other data source to which the gauge can be calibrated. Thus we cannot determine where the actual pressure is relative to the measured data. Prior to the implementation of continuous recording of pressure, there is no way to ascertain where in this band the discrete measured values may fall. If the recorded value is at the low end of the band, the real value could be 40kPa higher. Conversely if the recorded value is at the high end of the range, the real value could be 40 kPa lower. This 80 kPa error window is as great as the transient being examined. Any pressure trend drawn within this envelope is possibly correct. As stated on pg. 38 of Petro-Canada's submission, when a pressure value falls within the range of gauge resolution it is therefore not meaningful. If this logic is rejected, then the issue of a pressure response prior to production shut in remains. The Board recognized these problems in the initial hearing and rejected Petro-Canada's conclusion. No evidence has been provided which should compel the Board to alter its findings.

The use of piezometric data to show pressure communication through regional shales was also found to be problematic during the first interim hearing for Chard. During that hearing the use of Piezometer data was extensively debated. In the end the Board concluded:

“in the absence of any other information, these changes in pressure over time are as likely to represent 1) instrument drift of an unknown origin, 2) the decaying remnant of drilling-induced pressure pulses around the borehole, or 3) the transmittal of pressure decline down the borehole, as they are to be due to the effects of overlying gas production being transmitted vertically through the formation away from the borehole” (Decision 2003-023, pg. 24).

It went on to state:

“the Board recognizes that pressure-transmission via borehole pathways is impossible to distinguish from pressure-transmission vertically through the formation and across bedding. Because multiple interpretations of the piezometer data are possible, the Board finds it cannot use the submitted piezometer data to ascertain the degree of vertical penetration of pressure transients from top gas downwards into bitumen-bearing zones at Chard-Leismer” (Decision 2003-023, pg. 25).

In Section 5.2.2 of Petro-Canada’s submission, piezometer data from the 10-14-79-7W4 well is presented. In this case, the two relevant gauges are the one placed in an upper gas sand (297.9m Kb), and a second located below the regional McMurray A2 mudstone (311.7m Kb). The upper gauge shows a decline in pressure which Petro-Canada ascribes to production from offsetting wells. The response of the underlying gauge is the evidence Petro Canada points to in support of pressure communication through regional shales.

An examination of the response shows several things. Firstly, the gauge shows an increasing pressure trend from mid April to September 2003 (Figure 23). Petro-Canada suggests this is a pressure transient arising from drilling operations. CNRL contends this is unlikely. Normal drilling operations are carried out in an overbalanced state, thus the formation should be at its maximum pressure immediately after drilling, and pressure should dissipate (drop) from that point. Further, core analysis from the well shows this gauge to be located within a sand with a measured porosity of 35-38%. Although not directly measured, the permeability of clean McMurray sands of this type commonly runs to several darcies. As such, any pressure transient encountered would be expected to dissipate very quickly. A more likely explanation is that this behavior represents a malfunction or gauge drift. An examination of the declining pressure from September 2003 to December 2004 shows the rate of decline over this period (approximately 2.9kPaa/month) is similar to the rate of increase described above (2.4kPaa/month). If the increase in pressure represents drift, it is possible the later drop represents the same thing.

There is also a substantial increase in scatter and a drop in pressure during mid December 2003 to January 2004 (Figure 24). CNRL believes this behavior cannot reflect downhole conditions, and is more likely related to operating practices. At the Chard hearings evidence was presented that showed these instruments are sensitive to input voltage at

surface (Decision 2003-023, pg 24). What is of more concern, is that subsequent to this period, the rate of decline is changed (Figure 24). This pattern is repeated in August and Oct 2004 where apparent short term pressure drops are followed by changes in decline rate. The pattern indicates that not only are operating practices altering the short term pressure readings (during the spikes) but may also be altering the long term readings from the gauge.

Based on the two observations described above, the reliability of the gauge is questionable. But even if one were to overlook these problems, the real issue is; whether the decline in pressure represent vertical pressure transmission through the regional shale. CNRL contends that it is far more likely that this decline (if it is real) is due to pressure transmission via borehole pathways (behind pipe). A similar argument can be made for the 9-24-80-7W4 case study Petro-Canada presented in section 5.4.1 of its submission. The apparent pressure equilibration (Figure 25) can quite easily be explained by pressure transmission via borehole pathways.

As demonstrated above, piezometric data on its own is at best ambiguous, and does not allow any substantive conclusions to be made. At the first Chard interim hearing, the Board recognized the problems with this type of data and correctly rejected it in favor of more compelling evidence.

In Decision 2003-023 the Board ruled that the McMurray A and B mudstones act as barriers to pressure transmission. In its ruling it states:

“This conclusion is based on the areal extent of the McMurray A and B mudstones relative to the size of the overlying gas pools and top water zones, the distribution of reservoir fluids within the sands, and pressure data from segregated gas zones.” (Decision 2003-23 pg. 20)

The evidence provided by Petro-Canada has been presented and argued extensively in prior hearings. It contains no new or compelling arguments to demonstrate the Board was in error in its previous rulings. As such, the case for the shut in of the 9 wells listed by Petro-Canada has no merit and must be rejected by the Board.

3.2.4 Geologic Arguments

Section 4.3 of the Petro-Canada’s submission summarizes the 4 main geological arguments against the regional McMurray mudstones acting as pressure barriers. In the following sections, CNRL will show that these arguments have been made in past hearings and considered by the Board, and that no new substantive information has been presented which compels the Board to review its previous findings.

The first point Petro-Canada attempts to make is that bitumen staining within the condensed section of the McMurray A2 is indicative of a seal breach. This statement is

misleading. On page 10 of the submission Petro Canada states “The RGS reports that the base of the A2 mudstone is characterized by a five to twenty centimetre thick condensed section of bitumen-stained sands and muds (pg 17). Of particular note is the fact that the interval described is at the **base** of the McMurray A2 mudstone. The full RGS description of the A2 mudstone is:

“The mudstone at the base of the A2 Sequence is 1 to 2 m thick. The base of the A2 Mudstone is characterized by a 5 to 20 centimetre (cm) thick condensed section of bitumen-stained sands and muds, which grade into a 1 to 2 m thick grey mudstone.” (RGS Dec 2003, Pg 17).

Clearly the 1 to 2m thick grey mudstone is the main seal. No mention of bitumen within this unit is made and thus there is no evidence that the capillary displacement pressure was exceeded. The term “condensed section” generally refers to a marine stratigraphic interval characterized by very slow sedimentation rates. The presence of sands within the muds at the base of the A2 suggests some rapid high energy sedimentation; therefore this term is probably incorrect. CNRL believes this basal interval represents some form of reworked lag deposited at the very beginning of the transgression. The sand also provides the permeability which allows bitumen to penetrate this basal zone. The overlying mudstone does not contain sand and is therefore impermeable.

Petro-Canada also states that the mudstone is only 1m thick in the Chard lease area and state that modest lithologic variability can change the uniform seal properties (Petro-Canada Feb 14 submission, pg. 26). As Petro-Canada notes “Theoretically, a few centimeters of shale may be capable of trapping a large column of hydrocarbon” (pg. 11). The 1-2m thickness of the mudstone in the Chard area is not new information. It was established at the first Chard hearing, confirmed in the regional geologic study, and the second interim hearing. In each hearing the Board was aware of this thickness when it considered all of the evidence. Similarly the case for lithologic variability is not supported by any evidence, certainly none respecting the 9 wells requested for shut in. In essence this point is one that has been argued and ruled on repeatedly in the past. With no new evidence, the Board has no basis or reason to change its previous ruling.

Next Petro-Canada brings forward a variety of characteristics that they believe are a concern; the bayfill mudstone has been cut by channels; tributaries and distributaries are connected to channels; the mudstone is not fully marine and therefore incapable of providing a reliable regional seal; the drilling density is insufficient. Again, each of these are theoretical that were raised in previous hearings. Once again no new evidence has been provided, particularly with respect to the 9 wells listed for shut in by Petro-Canada. Each point was argued and considered by the Board in the previous hearings. With no new evidence, there is no basis for a change in findings.

The final geological argument put forward postulates a breach of seal integrity by salt solution induced structural shifts or thermal processes. The fact that the McMurray oil sands have undergone salt solution driven structuring has been recognized for decades. The single piece of evidence provided to support the Petro-Canada case was the

interpretation of a paleozoic fault with 2m throw from cross well seismic. There is no evidence showing this fault has any impact on the oil sands, and certainly none that directly pertains to the 9 wells listed by Petro-Canada.

With respect to the potential for mudstone to fail under thermal conditions the Petro-Canada evidence consists of a list of papers from which no details are provided as to what depths, pressures, temperature, thicknesses or other characteristics were tested, and what assumptions were used by the authors. With two of the papers unpublished, and no discussion as to the methodologies and applicability of these studies, the Board has no way to judge their relevance. The Petro-Canada summary that tight mudstones will fail, and permeable mudstones will leak would lead to the conclusion that a SAGD chamber could not be confined anywhere within the Mannville. With more than a decade of SAGD operations in the McMurray there should by now be considerable field evidence of this. As Petro-Canada has provided no substantive evidence to back this claim, the Board is left in the same situation as at the first Chard interim hearing where this issue was raised as a theoretical risk, but with no evidence to confirm or deny its reality. The Board concluded at that time that the thickness of the McMurray regional mudstones was sufficient to mitigate this risk, and with no new evidence must conclude the same again.

3.2.5 Conclusion

In the Petro-Canada submission of February 14 the Board was requested to shut in 9 wells because “a geologic review and pressure data analysis which indicates that production from natural gas wells identified for shut in is impacting the potentially recoverable bitumen”(pg.1). Yet no evidence was presented which demonstrated this association. Instead, Petro-Canada relies on analogies and generalities to try and support their case. As has been demonstrated in the previous sections the pressure analogies put forward are either incorrect, or open to multiple interpretations. As such, they do not constitute evidence on which the Board should change its previous rulings. Similarly, the geologic evidence consists of a list of hypothetical risks rather than specific evidence on the 9 wells. These risks have been extensively argued in past hearings, and again Petro-Canada has provided no compelling new evidence on which the Board might base a change in findings.

In the First Chard hearing the Board ruled that:

“where present, the McMurray A and B mudstones act as barriers to vertical pressure transmission and, therefore, that pressure depletion of gas zones overlying these mudstones should not be transmitted to underlying sediments. This conclusion is based on the areal extent of the McMurray A and B mudstones relative to the size of the overlying gas pools and top water zones, the distribution of reservoir fluids within the sands, and pressure data from segregated gas zones”(Decision 2003-23, pg. 20) .

It went on to rule:

“in the absence of evidence to the contrary, that these mudstones would remain competent in a thermal environment” (Decision 2003-23, pg 22).

Following the re-argument of many of these same issues at the First Interim Proceeding the Board stated:

“at this time the Board sees no need to shut in intervals where, based on existing data, the pool has a mudstone/shale unit meeting the RGS criteria separating the gas from potentially recoverable bitumen throughout the entire region of influence” (Decision 2004-045, pg.7).

With no substantive new evidence to counter these findings, they must be reaffirmed.

3.3 Nexen and SSG

3.3.1 Introduction

In its Feb 14 submission, the SSG recommends that the Wabiskaw D shale be entirely discounted as a regional pressure barrier, based on its core study. In requesting the shut in of wells that have not been cored, Nexen is in effect requesting the same thing. This request represents a significant departure from findings of the Board in previous Chard hearings. If the Board were to agree with this request, it would not only affect wells where core evidence supports the shut in of gas zones, but also wells where core evidence does not support this conclusion, wells that are not cored at all, and all future wells drilled in the area. Clearly such a sweeping decision must be based on conclusive proof that the Wabiskaw D shale is not a seal. A comparison of the Nexen and SSG core analysis shows that the analysis provided are contradictory and inconsistent, and clearly do not meet the standard required to overturn the previous rulings. CNRL believes that the Board must reject the sweeping ruling sought by Nexen and the SSG and continue to evaluate the Wabiskaw D shale on a pool by pool basis.

3.3.2 Historical Approach

In Decision 2003-023, after months of hearings, the Board concluded that:

“the McMurray A and B mudstones act as barriers to vertical pressure transmission and, therefore, that pressure depletion of gas zones overlying these mudstones should not be transmitted to underlying sediments. This conclusion is based on the areal extent of the McMurray A and B mudstones relative to the size of the overlying gas pools and top water zones, the distribution of reservoir fluids within the sands, and pressure data from segregated gas zones.” (Decision 2003-023, Pg.20).

In relation to the Wabiskaw D shale it went on to state:

“Based on similar observations, the Board also believes that the Wabiskaw D shale, where present, acts as a barrier to vertical pressure transmission, such that pressure depletion due to production of gas from above the Wabiskaw D shale would not be transmitted to the sands below the shale.” (Decision 2003-023, Pg.20).

It went on to conclude:

“The Wabiskaw D shale, however, varies in thickness over the Chard-Leismer area, from being absent in the western portion of Leismer to about 2 m thick in the Chard area. As a result, and until further data become available, the Board has decided to assume that where the Wabiskaw D shale is greater than or equal to 0.5 m thick, it would remain competent in the presence of a SAGD steam chamber, and where it is less than 0.5 m thick, it would not remain competent.” (Decision 2003-023, Pg.22).

This ruling means that the Wabiskaw D shale must be examined on a pool by pool basis to determine if it meets the criteria set out by the Board. This approach is both a reasonable and logical method for dealing with a unit that mapping, fluid distribution and pressure data show are a seal. This approach has been utilized in subsequent hearings and has resulted in the shut in of numerous gas wells that the Board felt may have posed a risk to significant accumulations of potentially recoverable bitumen.

The submission of the SSG seeks to have this fair and balanced approach removed, and a blanket rejection of the Wabiskaw D shale as a seal imposed. This sweeping request in effect will permanently remove the Wabiskaw D shale as a potential seal in any pool, no matter how compelling the data presented by the gas producer. The Nexen submission is less explicit in its request, but the fact that only 5 of the 17 wells they seek to have shut-in have direct core evidence to support their case, demonstrates they too seek a blanket ruling.

In Decision 2003-023 the Board did reject some mudstone types as potential seals. It concluded that abandoned channel plugs, IHS muds, and mud breccias would not act as seals, as the evidence conclusively showed they were deposited in a channel environment, and were not laterally extensive. In order for the Board to make a similar finding for the Wabiskaw D shale, the evidence presented must be so compelling, that in the future it should not even bother considering the possibility of this unit acting as a seal. If the evidence fails to meet this test, the Board must reject the request of Nexen and the SSG, and continue to examine the possibility of the D shale as a seal, on a pool by pool basis.

In the following sections, CNRL will show that the evidence presented by the SSG and Nexen is contradictory and inconsistent, and therefore clearly does not meet the requirement of certainty called for to impose a blanket dismissal of the Wabiskaw D mudstone. These submissions will also be used to show that although core is thought of as hard data, its analysis is highly subjective, and therefore prone to a myriad of interpretations, based largely upon an individual's opinion.

3.3.3 Uncertainty in Thickness Determination from Core

The use of core to establish the “true” nature of a particular unit would appear, at first glance, to be conclusive because the features in question are directly observed. In examining the details of such an exercise, it becomes abundantly clear that defining a unit from core involves a high degree of subjectivity. As stated in the submissions of both the SSG and Nexen, the determination of thickness and character of the Wabiskaw D shale from logs may not be definitive. Each propose that definitive evaluations of this unit can however be made from core. While true in a theoretical sense, this approach relies on a series of assumptions. If some or all the assumptions are not correct, the findings of the study cannot be considered proven.

The first assumption involved in assessing the thickness and quality of a unit from core is there is a clear and exact definition of what constitutes a particular unit such as the Wabiskaw D shale. The Wabiskaw D shale was initially defined largely on a petrophysical basis, with the sedimentological description developed on the basis of a cursory examination of a few core. This resulted in a definition which did not recognize some of the complexities that may exist in the unit. When subsequent studies were carried out, geologists changed their definitions to suit their perception of the new data. The evolution of these definitions is driven by the experience, personal theories and bias of the geologist. This can and does result in a diversity of opinion.

This issue is manifest in the data presented by Nexen and the SSG. The SSG apparently worked with a very narrow set of criteria to define the Wabiskaw D shale. Nexen appears to use a somewhat broader interpretation of what constitutes the Wabiskaw D shale. The resulting contrast between the lumpers and splitter approach is shown by the fact that of the 41 core examined by both the SSG and Nexen, there are 27 (66%) in which Nexen reports the presence of the Wabiskaw D shale, but which the SSG reports its absence (Figure 26). This contrast is striking as both studies were carried out by groups supporting shut in of gas. One can only assume that a study of these core by a geologist more sympathetic to the gas producers' cause would only add to the confusion.

This is further complicated by the fact that even when geologists agree on the presence of a unit such as the Wabiskaw D shale in a well, there remains the difficulty in establishing what defines the top and base of the unit. If lithologies are unique (eg. a carbonate in a clastic sequence) and the boundaries abrupt, this can be simple. In more ambiguous situations, such as the Wabiskaw D shale, the boundaries become much less clear. Does a shale unit end at the first sand interbed (no matter how small), where sand interbeds

become dominant, or at somewhere in between? Each geologist will have an opinion based on their background and personal bias, and none can be proven to be wrong. The lack of a common rigid standard means there are no unique solutions. This problem is again evident in the presentations of the SSG and Nexen. Of the 41 cored wells examined by both Nexen and the SSG there are 4 in which both provide thickness measurements for the Wabiskaw D shale (Figure 27). In these wells, the larger measured thickness is between 1.5 and 3 times thicker than the smaller measurement for the same core. Again this disparity of opinion is between 2 groups on the same side of the gas/bitumen issue.

Furthermore, problems described do not address all the potential issues with using core to determine the thickness and nature of a thin unit. In order for a core to show the actual thickness of a particular unit one must assume that the core has cut and recovered its entire thickness. If core is missing, it is up to the geologist to identify what part of the core was lost, and determine how this affects the interpreted thickness of the unit. For thin intervals approaching log resolution, there is no way to confirm with certainty which part of the cored interval is missing. The geologist simply guesses, based on rules of thumb, experience, and personal bias, where the core was lost from. As these factors vary from geologist to geologist, the reported recovery of a unit within a cored interval will also vary.

With thin units such as the Wabiskaw D shale the recognition of small amounts of lost core becomes problematic. An examination of the core photos shows it is not uncommon for the core to be broken up. These fractures occupy space, causing the core to expand in length. Thus the loss of small amounts of core (0-20cm) may be difficult to recognize if the fractured core expands to mask the loss. Since an artificial cutoff of 0.5m is being applied to the Wabiskaw D shale, even small amounts of lost core may be sufficient to dramatically alter the interpreted seal capability of the shale.

In the case of the Wabiskaw D shale this issue is clearly important. An examination of the reported core recovery from core measured by the SSG shows that more than 70% of the cores in which the Wabiskaw D shale was encountered report some lost core (Figure 26). As stated previously, the recognition of lost core is difficult, and thus this figure is likely a low side estimate. A comparison of the 41 cores examined by both Nexen and the SSG show that there are 2 in which Nexen concludes the Wabiskaw D shale was not cored or core was missing, but which the SSG sees no such problem (AA/12-21-085-06W4/0 and AA/16-36-085-07W4/0).

In summary, in order for core to assess fully the character and thickness of the Wabiskaw D shale it must fully recover the interval, and must be evaluated using agreed to standardized criteria. Failure to do this results in contradictory and inconsistent data based largely on the personal opinion of the geologist. This problem is clearly illustrated by the fact that two parties on the same side of the GOB issue generate such different results examining the same core. It also demonstrates that had gas producers had sufficient time to carry out their own study, the results would only add further confusion.

3.3.4 Other Core Evidence

In Decision 2003-023, the Board ruled that the Wabiskaw D shale was a regionally correlatable unit. This unit, based on the areal extent relative to the size of overlying gas and top water zones, the distribution of reservoir fluids within the sands, and pressure data from segregated gas zones, was found to act as a pressure seal. This finding, combined with the observed variation in thickness of the unit led the Board to rule:

“where the Wabiskaw D shale is greater than or equal to 0.5 m thick, it would remain competent in the presence of a SAGD steam chamber, and where it is less than 0.5 m thick, it would not remain competent.”

In seeking the complete rejection of the Wabiskaw D shale as a seal the SSG and Nexen need to show conclusively that the Board was in error when it concluded that the unit was regional in nature, or had the potential to act as a pressure seal. Although the SSG data claims to show that the Wabiskaw D shale is not regionally extensive, the evidence of Nexen contradicts this, mapping the shale in many of the wells the SSG states it is absent from. In essence, the SSG’s claim is unproven.

Nexen claims that the identification of vertical burrows proves that the Wabiskaw D shale cannot be considered a pressure seal. Its data set shows that these burrows occur in less than ½ of the wells examined, and only 4 of the 134 listed show bitumen staining that suggests these burrows provide any permeability at all. No data was provided to demonstrate that these burrows penetrate entirely through the shales and act as pressure conduits. Without this evidence, the presence of burrows is simply an observation, one that has been made repeatedly in the past. One must assume that if burrow conduits were so widespread as to warrant the dismissal of the shale as a seal, the Board would not have seen the fluid distribution and segregated pressure data which led it to draw the original conclusion that it was a seal. Thus Nexen’s case is also not proven.

In summary, neither the SSG, nor Nexen has provided widespread evidence that conclusively demonstrates that where the Wabiskaw D shale is greater than 0.5m it does not act as a pressure seal. Since none of the key features on which the Board made its ruling have been shown to be incorrect, there is no basis for the general dismissal of the Wabiskaw D shale greater than 0.5m as a seal. CNRL contends that the original ruling should stand, and the Wabiskaw D shale be considered a seal where greater than 0.5m. In this scenario pools must be examined on a case by case basis.

3.3.5 Wabiskaw D Shale Thickness from Logs and Core

In Decision 2004-045 the Board states that:

“The Board continues to recognize that well logs may not be definitive in determining mudstone/shale thickness and character. Given that there are insufficient core data available, however, the Board is satisfied that

the application of consistent criteria to well log evaluation is the most effective tool for recognition of regional mudstones and shales.”

Both Nexen and the SSG have provided data sets which each claims provide definitive proof that logs overstate the Wabiskaw D shale thickness. As described above, such a conclusion can only be reached when one can definitively measure the thickness of the Wabiskaw D shale. Like logs, the determination of thickness from core requires the application of consistent criteria. As has been demonstrated by the contradictory measurements provided by both groups, we are far from that point. Thus CNRL believes that the Board should refrain from reaching sweeping conclusions based on these data sets. Once again, logic dictates that the thickness of the Wabiskaw D shale be examined on a pool by pool basis, as has been the practice in the past.

3.3.6 Wells requested for shut in by Nexen

Nexen has requested the shut in of two groups of wells, gas wells and bitumen evaluation wells.

Bitumen Evaluation Wells

- 1AA/11-01-086-07W4/0
- 1AA/02-11-086-07W4/0
- 1AA/06-23-086-07W4/0
- 1AA/11-23-086-07W4/0
- 1AA/07-26-086-07W4/0
- 1AA/06-28-086-07W4/0
- 1AA/07-33-085-07W4/0

Gas Wells

- 100/05-07-084-06W4/0
- 100/06-09-084-06W4/0
- 100/05-10-084-06W4/0
- 100/07-16-084-06W4/0
- 100/09-17-084-06W4/0
- 100/03-18-084-06W4/0
- 100/10-20-084-06W4/0
- 100/10-21-084-06W4/0
- 100/13-27-084-06W4/0
- 100/15-17-085-06W4/0

In the case of the bitumen evaluation wells, CNRL is puzzled by the request. Board regulations require bitumen evaluation wells to be abandoned shortly after they are drilled. Industry practice is to abandon such wells immediately after logging, generally without setting casing. As such, there is no possibility of re-entry and completion. These wells are now, and forever, incapable of production. To request the shut in of well incapable of production serves no purpose. Further, should a well be drilled nearby, it would constitute new data, and would require an ID-99-1 application to produce. The

creation of new data could ultimately form the basis for a new hearing. Thus, a Board ordered shut in does not serve any future purpose.

The seven bitumen evaluation wells Nexen lists for shut in were contested in the previous interim hearing. Both the logs and cores from these wells were presented as evidence at that time. Nexen and CNRL argued fully all this evidence before the panel. Based on this evidence, the Board rendered its decision (2004-045), which was to allow these wells to produce. Nexen has provided no further evidence which pertains directly to these wells. As such, when examined on a pool by pool case, there is no basis on which to alter the previous rulings. The Board must reject this request.

Similarly, all of the gas wells Nexen seeks to shut in were examined in the previous interim hearing. In this case, none of the wells have been cored. Thus neither the core study of Nexen or the SSG provides any new evidence which directly bears on these pools. With no new evidence pertaining to these pools, the Board has no basis on which to alter its previous findings.

These wells do however, provide a graphic example of why the Board must reject both the SSG and Nexen's request to entirely dismiss the Wabiskaw D shale as a seal. Both interveners seek to have these wells ordered shut in by having the D shale dismissed. If they were successful, these would be 17 examples of wells which would be shut in, despite the fact that the evidence pertaining to those pools was sufficiently strong to convince the Board these were isolated from bitumen.

3.3.7 Wells requested shut in by the SSG

The SSG list of wells it seeks to have shut in contains 24 CNRL operated wells in the Newby and Chard area (Figure 29). Of these, 22 have not been cored. The SSG recommended 14 of the 22 wells be given a produce status in the interim hearings. In their February 14th submission the SSG provides no new evidence which directly addresses the nature of the Wabiskaw D shale in the area of influence for these wells. Despite this, the SSG now seeks to have these shut in. The remaining 8 wells were recommended for shut in by the SSG, but were disputed by CNRL at the interim hearings. Having heard the arguments of all parties, the Board ruled that all 8 should be allowed to produce. The SSG seeks to have this ruling overturned on all 8, but provides no evidence to show that the Wabiskaw D shale is not a seal within the area of influence. CNRL contends that for the reasons presented previously, the Wabiskaw D shale must be examined on a pool by pool basis. In the case of these 22 wells, no evidence has been submitted to show that the previous ruling of the Board was in error. Therefore, the production status of these wells should remain unchanged. These wells also form another example of a group of wells which a sweeping rejection of the Wabiskaw D shale would shut in, despite the fact that when they were examined on a pool by pool basis, the evidence showed these wells to be isolated from Bitumen

The two remaining wells (AA/6-28-86-7W4 and AA/7-33-86-7W4) are cored. As these wells are abandoned bitumen evaluation wells, they are now, and for ever more, incapable of production. Despite this, in the interim hearing they were examined by the SSG, who identified the Wabiskaw D shale from logs, and determined it to be greater than 0.5m. Based on this, they recommended a produce status for these wells. This status was duly conferred in decision 2004-045. Having now examined the core in these two wells, the SSG has determined the Wabiskaw D shale is entirely absent. Nexen however has examined the same core and determined both contain the Wabiskaw D shale. They furthermore determined that the thickness of the shale in AA/6-28-86-7W4 is both understated by the logs, and exceeds the 0.5m cutoff. CNRL believes that although academic, the production status of these two wells should not be changed. At best the evidence against these wells is contradictory or inconsistent, and in the case of 6-28, the log and core evidence of Nexen indicate the Wabiskaw D shale is present, and exceeds the Board's 0.5m cutoff.

The SSG also lists 30 wells (7 CNRL) from the Hardy Wabiskaw McMurray A Pool (Hardy Wabiskaw M Pool in Board order system) for shut in. This is once again a Wabiskaw C sand pool that was recommended for shut in by the SSG in the Interim Hearing. This recommendation was contested by CNRL and others, and after hearing all the evidence, the Board granted this pool a produce status. The SSG seeks to have this decision overturned. The new evidence provided is the core study. An examination of the data shows that the new evidence pertaining to this pool is a core derived Wabiskaw D shale thickness from one well. This data point indicates that the D shale is present in 9-36-77-6W4, and its thickness is 75 cm thick (25cm more than is required to be considered a seal). No other wells have core. Thus, all of the new evidence supports the Board's original finding. Based on this it is obvious that the request of the SSG concerning this pool is entirely groundless, and must be denied.

3.3.8 Conclusions

The SSG and Nexen have asked the Board to overturn its previous rulings and dismiss the possibility that the Wabiskaw D shale is a seal. They do this on the basis of core studies that CNRL has shown are conflicting and contradictory. CNRL submits that such data is clearly insufficient to justify such a sweeping change. CNRL believes that the previous approach of examining evidence on a pool by pool basis is still a logical and reasonable approach. If the wells requested for shut in are examined in this way, it is clear the evidence on which they rely to overturn previous rulings is extremely weak, or non-existent. For these reasons, the Board must deny the request for shut in, and maintain the previously ordered production status.

4.0 DUNCAN, LEISMER, THORNBURY AREA

The SSG has made a request to have changed the status of a number of CNRL operated wells in the Duncan, Leismer and Thornbury area. The SSG bases these requests on new

pressure data, and repooling on the basis of fluid contacts. CNRL believes that when properly interpreted, pressure data can be a valid tool for pooling wells. CNRL does not agree with the pooling of adjacent regional wells to channel wells on the basis of fluid contacts alone. After an exhaustive hearing at Chard the Board concluded:

“The Board does not interpret the McMurray A regional sand gas pools to be connected with gas within laterally offsetting channel sediments, nor the McMurray A regional top water zones to be connected with top water within laterally offsetting channel sediments.” (Decision 2003-023, Pg. 27)

It also stated:

“Based on its review of the gas and top water zones, the Board disagrees with Nexen, and Petro-Canada that lateral communication pathways commonly exist between regional Wabiskaw C, McMurray A, and McMurray B2 sands and McMurray channel sands.” (Decision 2003-023, Pg. 28)

In summary the Board concluded:

“lateral communication pathways do not commonly exist between regional Wabiskaw C, McMurray A, McMurray B2, and Wabiskaw D valley-fill gas pools and/or top water zones and McMurray channel gas pools and/or top water zones” (Decision 2003-023, Pg. 29)

This finding was incorporated into RGS gas pooling methodology where the first criteria listed required for pooling was:

“Gas was present in the same stratigraphic interval” (RGS Pg 75.)

The proposed poolings of the SSG based on fluid contacts alone go against the criteria outlined in the RGS, and the Board ruling upon which it was based. It does so without commenting why these findings should not apply, and proving the case that these conclusions were incorrect. CNRL believes that the original findings were based on the comprehensive evaluation of all the available data, and that these should not be abandoned until a comprehensive study of all the data shows them to be wrong. On this basis CNRL believes that the pooling of gas in regional strata with that of channel strata solely on the basis of fluid contacts must be rejected.

5.0 CONCLUSIONS

CNRL and ISH have conclusively demonstrated that the Wabiskaw B Valley fill at Kirby is inferior to both the McMurray in Kirby, and the Wabiskaw at Tar – Ells. They have also shown that if the appropriate cut off (20m) is applied, and geology examined, the Upper Manville J, U2U, V2V and II pools are not in association with potentially

recoverable bitumen. CNRL also contends that the SSG does not present new evidence that supports their request for shut in of the Upper Mannville O3O pool and 3-21-74-7W4, and this request should be denied.

None of the evidence presented by Petro Canada directly related to the wells they seek to have shut in. The data that was provided has been shown to be inconclusive, and the conclusions drawn from it unsupported or incorrect. Most of it has been presented to the Board in previous hearings, where it was judged not to be compelling. For these reasons Petro Canada's request should be denied.

Nexen and the SSG seek to have the Wabiskaw D shale removed from consideration as a sealing unit. In so doing, they seek the shut in of a large number of wells. CNRL has demonstrated that the two studies are inconsistent and contradictory, and thus are insufficient evidence to support such a sweeping ruling. The past practice of examining the nature of this shale on a pool by pool basis remains the reasonable and logical approach. When such an evaluation is done, the evidence does not support the alteration of the production status of the wells.

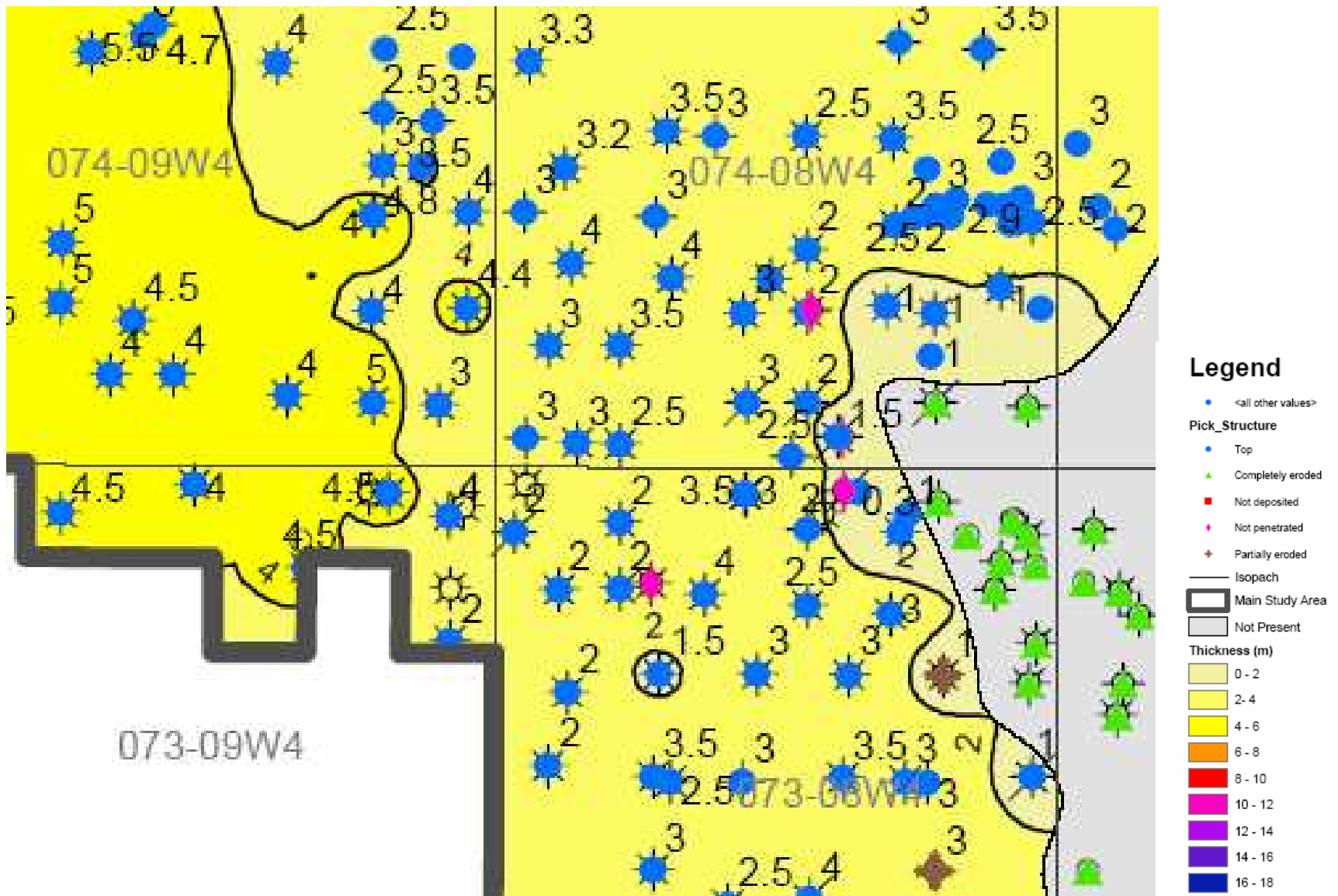


Figure 1: Isopach Wabiskaw C Sand. (Excerpt from Regional Geological Study)

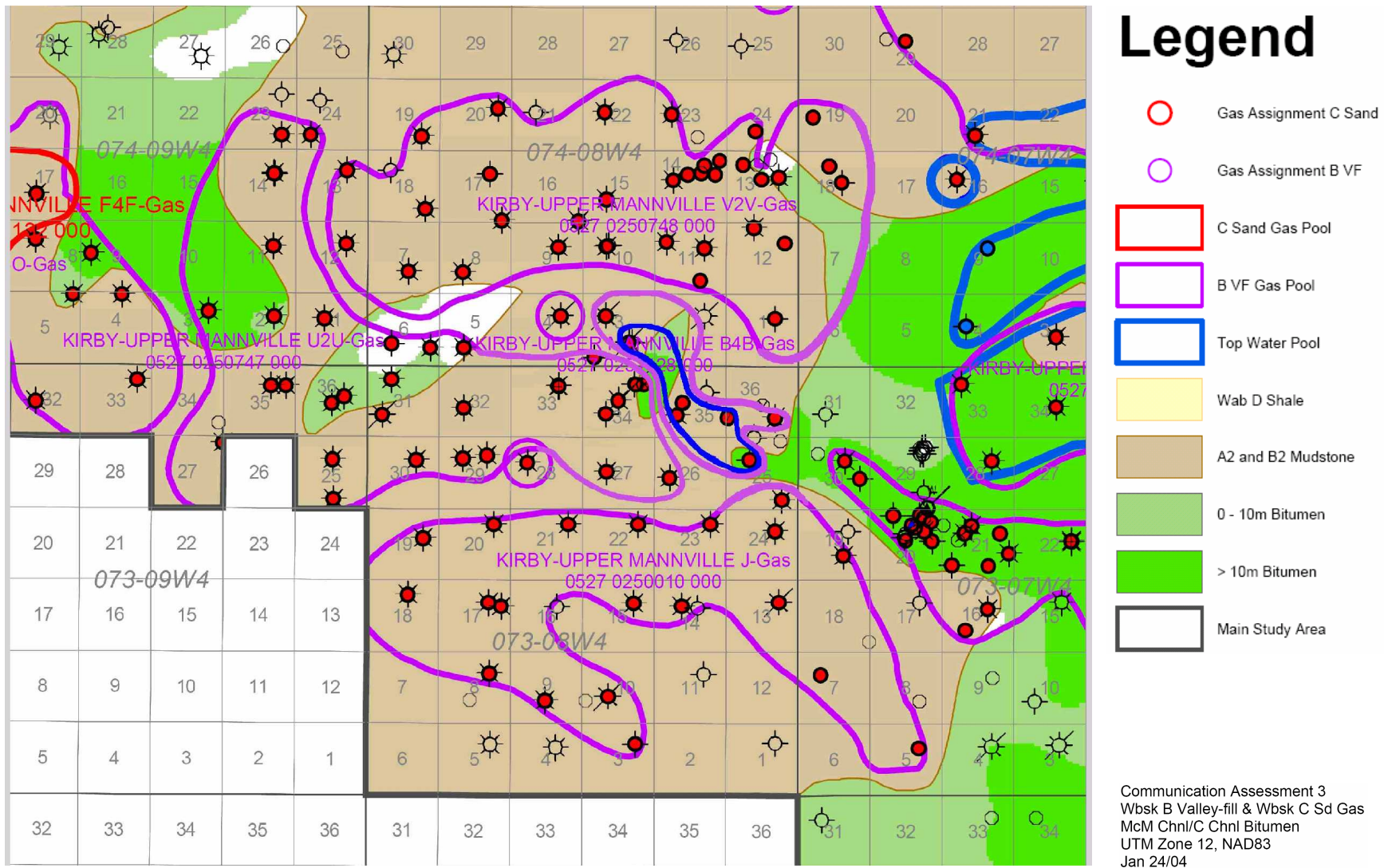


Figure 2. Wabiskaw B Valley Fill Proposed Pooling (Modified from SSG Bitumen Conservation Recommendations, Jan. 26, 2004)

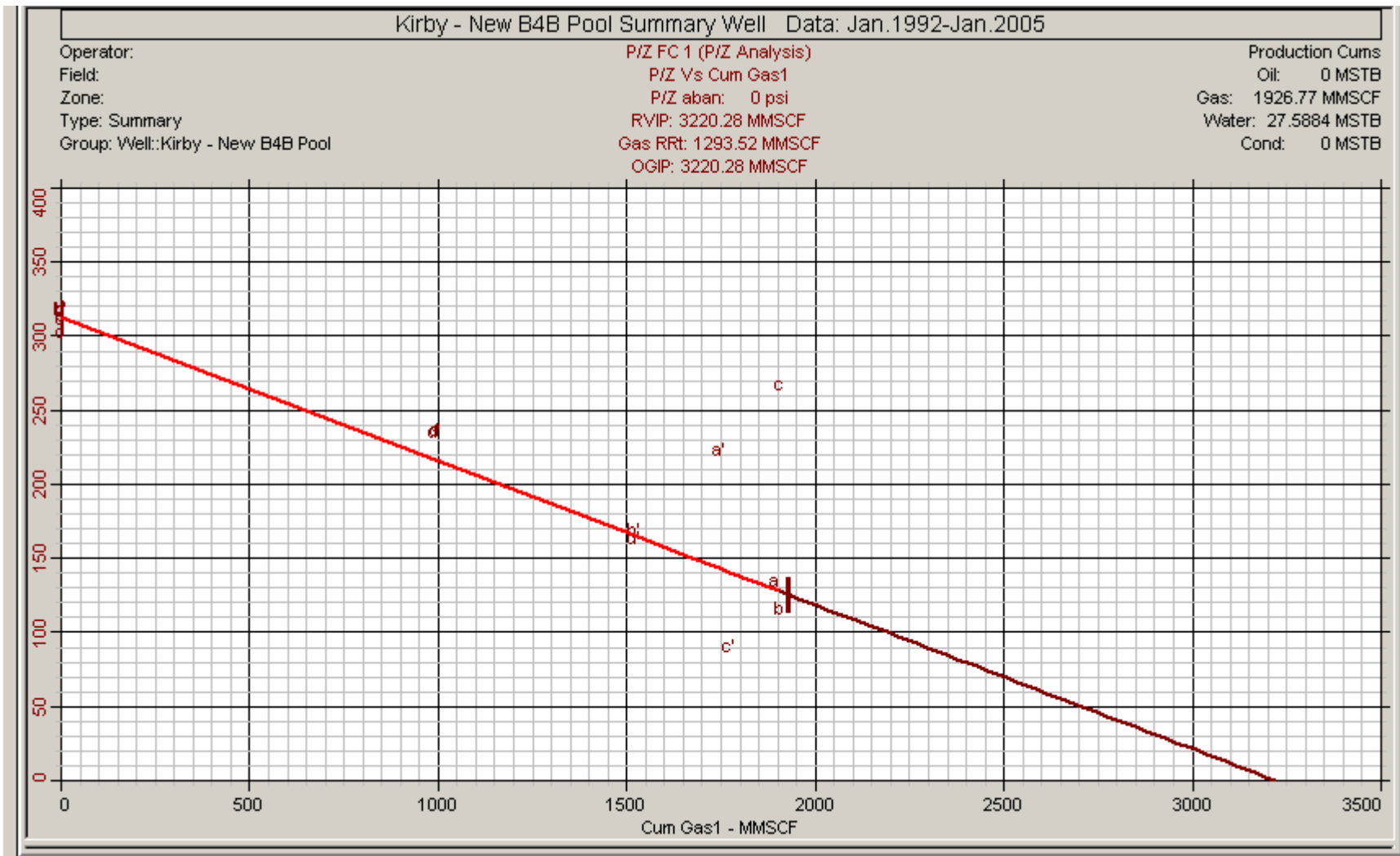


Figure 5. CNRL Revised B4B Pool Pressure Plot

B4B Pressure Data

Well: Kirby - New B4B Pool Summary Well
P/Z AOF Report

Gas Analysis

Gas Analysis Data		Gas Comp%	
Specific Gravity	0.562	C1	98.4703
Critical Pressure	4639 psi	C2	0
Critical Temperature	347 R	C3	0.01
		C4	0
		C4N	0
		C5	0
		C5N	0
Well Data		C6	0
Pool Datum	0 ft KB	C7+	0
Well Datum	0 ft KB	H	0
Kelly Bushing Elev	0 ft	HE	0.01
Casing Flange Elev	0 ft	CO2	0.2799
Reservoir Temp.	60 F	N2	1.2298
		H2S	0
		Total	100

Pressure Tests

Date y/m/d	Symbol	Use Test	Well Name	Test	Type	Calc P	P (Pool Datum)		Well Head		Run Depth		Gradient psi/ft	Calc Z	Z	CumGas MMSCF	Comments
							psi	hrs	psi	Temp F	ft KB	psi					
1992/01/09	b	Y	RAX NCR KIRBY 11-3-74-8	BH	StGrad	N	303.27	163	275.28	62.6	1475.07	303.27	0.13	Y	0.9572	0	
1992/01/09	b	Y	RAX NCR KIRBY 11-3-74-8	BH	Bldup	N	299.94	91.1	0	32	1486.22	299.94	0.02	Y	0.9577	0	
1992/01/14	c	Y	RAX NCR KIRBY 6-35-73-8	BH	StGrad	N	299.5	131.3	289.06	89.6	1500.98	299.5	0.01	Y	0.9938	0	
1992/01/14	c	Y	RAX NCR KIRBY 6-35-73-8	BH	Bldup	N	308.79	129.5	0	32	1512.14	308.79	0.01	Y	0.9936	0	
1995/12/16	d	Y	RAX NCR KIRBY A7-3-74-8	BH	StGrad	N	226.11	94.6	213.5	32	1460.63	226.11	0	Y	0.9622	993.82	
1997/12/22	d	Y	RAX NCR KIRBY A7-3-74-8	TH	N/A	N	158.24	504	0	32	2921.26	158.24	0	Y	0.9734	1519.35	
1997/12/31	b	Y	RAX NCR KIRBY 11-3-74-8	TH	N/A	N	164.04	8760	0	32	1474.74	164.04	0	Y	0.9765	1519.35	
1999/05/12	d	N	RAX NCR KIRBY A7-3-74-8	BH	N/A	N	0	8760	0	32	0	0	0	Y	1	1674.1	
2000/09/11	d	N	RAX NCR KIRBY A7-3-74-8	BH	N/A	N	0	20472	0	32	0	0	0	Y	1	1732.09	
2001/10/24	b	N	RAX NCR KIRBY 11-3-74-8	BH	N/A	N	0	720	0	32	0	0	0	Y	1	1772.28	
2001/10/24	d	N	RAX NCR KIRBY A7-3-74-8	BH	N/A	N	0	720	0	32	0	0	0	Y	1	1772.28	
2001/10/25	c	N	RAX NCR KIRBY 6-35-73-8	BH	N/A	N	0	24	0	32	0	0	0	Y	1	1772.28	
2003/06/28	a	Y	RAX 7A KIRBY 7-36-73-8	BH	StGrad	N	133.43	101	80.21	51.8	1559.38	133.43	0	Y	0.9972	1891.11	
2004/01/17	b	Y	RAX NCR KIRBY 11-3-74-8	BH	StGrad	N	112.98	3312	38.14	55.4	1474.41	112.98	0	Y	0.9837	1903.97	
2004/01/29	c	Y	RAX NCR KIRBY 6-35-73-8	BH	StGrad	N	264.55	3608.4	83.11	51.8	1476.38	264.55	0	Y	0.9945	1903.97	

Deliverability Tests

Date y/m/d	Symbol	Use Test	Well Name	Test	Type	Duration Hours	Gas Flow Rate mcf/d	Oil Flow Rate Bbl/d	Water Flow Rate Bbl/d	Flow Pressure psi	MPP Pressure psi	N Factor	AOF mcf/d	Calc Z	Z	CumGas MMSCF	Upper Perf. Depth ft KB	Lower Perf. Depth ft KB	Liquids per Day Bbl/d	GOR	Choke Size	Sediment and Water %	C Factor	Liquid Gravity	Oil Gravity	Water Gravity	Producing Method	Comment s			
																													1992/01/09	b	Y
1992/01/14	c	N	RAX NCR KIRBY 6-35-73-8	N/A	Single	48	0.79	---	---	284.42	308.64	1	5.25	Y	0.9936	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
1995/12/19	d	Y	RAX NCR KIRBY A7-3-74-8	N/A	Multi	14	0.82	---	---	200.15	225.68	0.94	3.61	Y	0.9623	993.82	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
2001/02/26	a	N	RAX 7A KIRBY 7-36-73-8	N/A	N/A	0	---	---	---	0	0	0	0	Y	1	1744.8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
2001/02/26	a	Y	RAX 7A KIRBY 7-36-73-8	N/A	Single	26	0.45	---	---	189.71	220.75	1	1.73	Y	0.9954	1744.8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
2001/10/25	c	Y	RAX NCR KIRBY 6-35-73-8	N/A	Single	24	0.07	---	---	36.69	89.34	1	0.08	Y	0.9981	1772.28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	

Well Symbol Key

Well	Name
a	RAX 7A KIRBY 7-36-73-8
b	RAX NCR KIRBY 11-3-74-8
c	RAX NCR KIRBY 6-35-73-8
d	RAX NCR KIRBY A7-3-74-8
e	Kirby - Top water pool Summary Well

Figure 6 CNRL Revised B4B Pool Pressure Data

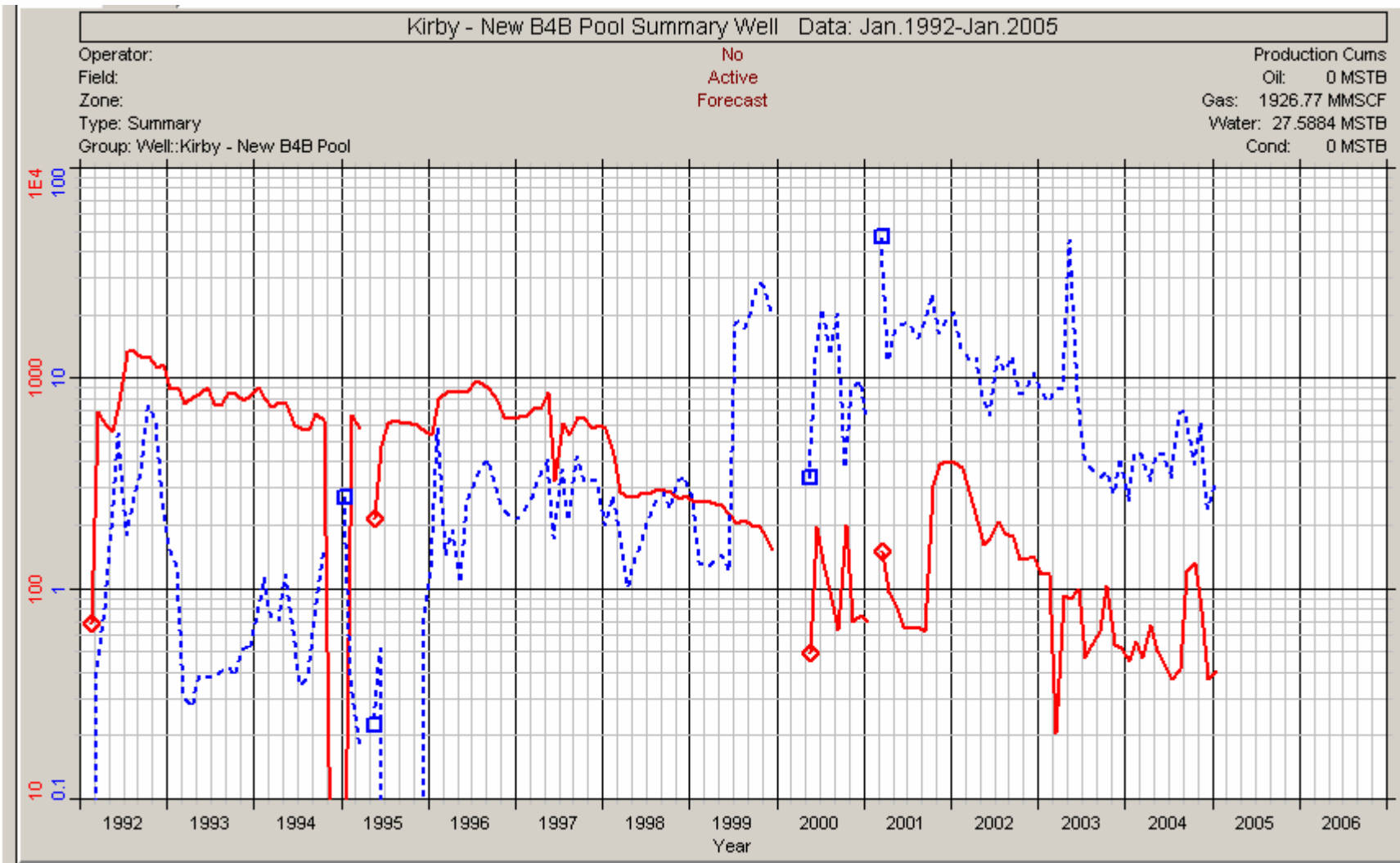


Figure 7 CNRL Revised B4B Pool Production Plot

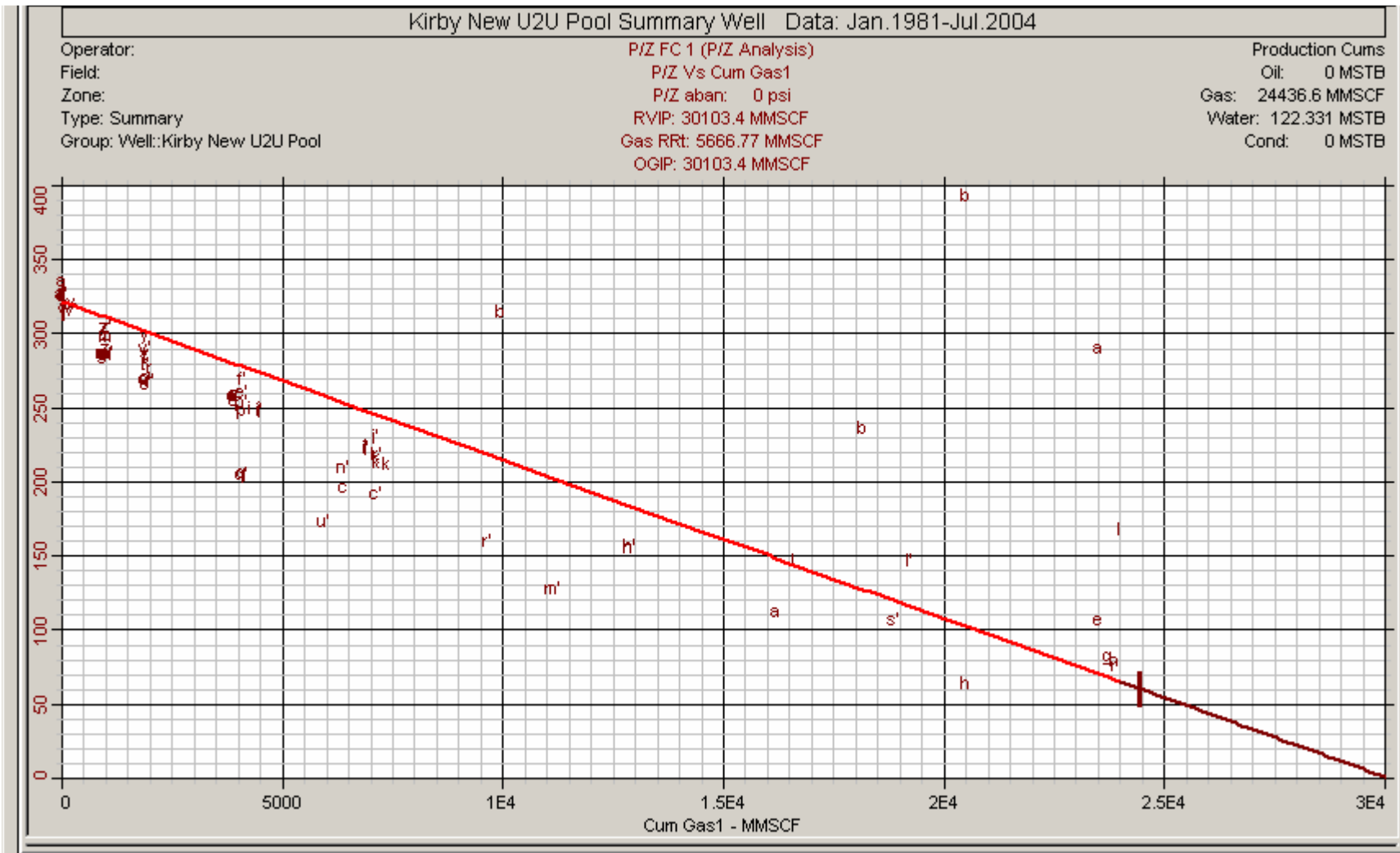


Figure 8. CNRL revised U2U Pool Pressure Plot

U2U Pool Pressure Data

Well: Kirby New U2U Pool Summary Well
P/Z AOF Report

Gas Analysis

Gas Analysis Data	Gas Composition %
Specific Gravity	98.4703
Critical Pressure	0.562
Critical Temperature	4639 psi
	347 R
	C1
	C2
	C3
	C4
	C5
	C6
	C7+
	H
	CO
	CO2
	N2
	NOC
	Total

Pressure Tests

Date	ym/d	Symbol	Use	Well Name	Test	Type	Calc	Well				Run Depth	Pressure	Gradient	Calc	Z	CumGas	Comments
								Datum	Shut-in	Pressure	Temp							
1981/01/22	a	Y	ISH ET AL KIRBY 5-26-73-8	BH	SI/Grad	N	309.95	0	291.82	32	1574.8	320.68	0.47	Y	0.9485	0		
1981/01/31	a	Y	ISH ET AL KIRBY 5-26-73-8	BH	SI/Grad	N	317.49	120.5	293.85	32	1574.8	317.49	0.49	Y	0.9473	0		
1981/01/31	a	Y	ISH ET AL KIRBY 5-26-73-8	BH	SI/Grad	N	308.21	82	299.79	32	1451.77	308.21	0.49	N	0.9488	0		
1993/02/05	w	Y	RAX NCR KIRBY 10-30-73-8	BH	SI/Grad	N	303.85	337.2	0	32	1427.49	304.14	0.02	Y	0.9495	140.98		
1993/02/14	w	Y	RAX NCR KIRBY 10-30-73-8	BH	SI/Grad	N	301.1	0	289.79	32	1427.17	301.39	0.02	Y	0.95	140.98		
1994/01/28	m	Y	RAX ET AL KIRBY 10-33-73-8	BH	SI/Grad	N	273.4	0	287.01	32	1489.34	273.4	0.01	Y	0.9545	840.18		
1994/01/30	s	Y	RAX ET AL KIRBY 6-32-73-8	BH	SI/Grad	N	270.35	0	263.68	32	1440.29	270.35	0.02	Y	0.955	840.18		
1994/02/04	z	Y	RAX NCR MARGIE 10-2-74-9	BH	SI/Grad	N	284.27	0	272.38	32	1397.64	284.56	0.02	Y	0.9527	890.66		
1994/02/07	m	Y	RAX ET AL KIRBY 10-33-73-8	BH	SI/Grad	N	283.11	194.9	269.19	32	1488.69	283.11	0.01	Y	0.9528	890.66		
1994/02/07	m	Y	RAX ET AL KIRBY 10-33-73-8	BH	SI/Grad	N	272.53	194.9	269.19	32	1489.34	272.53	0.01	Y	0.9546	890.66		
1994/02/07	z	Y	RAX NCR MARGIE 10-2-74-9	BH	SI/Grad	N	275.86	285.4	281.81	32	1397.31	276.15	0.03	Y	0.9541	890.66		
1994/02/18	z	Y	RAX NCR MARGIE 10-2-74-9	BH	SI/Grad	N	285.21	285.4	281.81	32	1397.64	289.64	0.03	Y	0.9519	890.66		
1995/01/01	y	Y	RAX NCR MARGIE 10-11-74-9	BH	SI/Grad	N	273.54	0	266.43	32	1372.38	273.54	0	Y	0.9545	1875.42		
1995/01/08	y	Y	RAX NCR MARGIE 10-11-74-9	BH	SI/Grad	N	283.84	160	0	32	1378.28	283.84	0	Y	0.9528	1875.42		
1995/01/14	o	Y	RAX ET AL KIRBY 3-5-74-8	BH	SI/Grad	N	258.17	0	248.45	32	1457.88	258.17	0.01	Y	0.957	1875.42		
1995/01/14	t	Y	RAX ET AL MARGIE 11-1-74-9	BH	SI/Grad	N	272.53	0	262.23	32	1375.66	272.53	0.01	Y	0.9546	1875.42		
1995/01/25	o	Y	RAX ET AL KIRBY 3-5-74-8	BH	SI/Grad	N	253.96	0	248.9	32	1463.58	253.96	0	Y	0.9577	1875.42		
1995/01/25	t	Y	RAX ET AL KIRBY 11-1-74-9	BH	SI/Grad	N	270.5	165	0	32	1381.58	270.5	0	Y	0.955	1875.42		
1995/02/11	r	Y	RAX ET AL KIRBY 5-31-73-8	BH	SI/Grad	N	255.56	0	256.6	32	1425.13	255.71	0.01	Y	0.9624	1984.08		
1995/02/21	r	Y	RAX ET AL KIRBY 5-31-73-8	BH	SI/Grad	N	257.44	177	0	32	1428.13	257.44	0	Y	0.9635	1984.08		
1995/12/19	e	Y	ISH KIRBY 1-23-74-9	BH	SI/Grad	N	244.24	9999.9	238.44	57.2	1365.81	244.24	0.02	Y	0.9592	3804.94		
1995/12/31	e	Y	ISH KIRBY 1-23-74-9	BH	SI/Grad	N	247.58	61.7	236.56	65.2	1372.7	247.58	0.01	Y	0.9597	3804.94		
1996/01/06	p	Y	RAX ET AL KIRBY 4-24-74-9	BH	SI/Grad	N	237.28	20.8	233.51	66.2	1371.06	237.28	0.01	Y	0.9604	4095.84		
1996/01/06	q	Y	RAX ET AL KIRBY 4-24-74-9	BH	SI/Grad	N	204.21	19	193.48	69.8	1501.31	204.21	0.01	Y	0.9597	4095.84		
1996/02/19	i	Y	PARA ET AL CLYDE LAKE 7-36-73-9	BH	SI/Grad	N	240.18	9999.9	238.44	55.4	1419.95	240.17	0.02	Y	0.9666	4490.53		
1996/03/05	i	Y	PARA ET AL CLYDE LAKE 7-36-73-9	BH	SI/Grad	N	238.3	264	0	53.6	1420.28	238.3	0.01	Y	0.9668	4490.53		
1996/03/05	l	Y	PARA ET AL CLYDE LAKE 7-36-73-9	BH	SI/Grad	N	240.04	264	0	59	1420.28	240.04	0.01	Y	0.9666	4490.53		
1996/12/27	c	Y	ISH HZ KIRBY 10-29-73-8	BH	SI/Grad	N	194.64	9999.9	185.45	53.8	1520.93	194.79	0	Y	0.967	8307.4		
1997/02/04	i	Y	PARA ET AL CLYDE LAKE 7-36-73-9	BH	SI/Grad	N	216.11	9999.9	209.43	53.6	1420.28	216.11	0	Y	0.9698	8892.51		
1997/02/21	i	Y	PARA ET AL CLYDE LAKE 7-36-73-9	BH	SI/Grad	N	214.37	291	207.55	53.6	1420.28	214.37	0	Y	0.9701	8892.51		
1997/02/21	j	Y	PARA ET AL CLYDE LAKE 7-36-73-9	BH	SI/Grad	N	214.95	290.9	207.55	53.2	1420.28	214.95	0	Y	0.97	8892.51		
1997/03/19	k	Y	PARA ET AL HZ CLYDE LAKE 10-36-73-9	BH	SI/Grad	N	205.23	0	201.46	46.4	620.08	205.23	0	Y	0.9677	7123.37		
1997/03/25	k	Y	PARA ET AL HZ CLYDE LAKE 10-36-73-9	BH	SI/Grad	N	208.71	36	201.46	42.8	1422.24	208.71	0	Y	0.9672	7123.37		
1997/04/01	k	Y	PARA ET AL HZ CLYDE LAKE 10-36-73-9	BH	SI/Grad	N	203.82	36	201.46	41	587.27	203.82	0	Y	0.9679	7123.37		
1997/10/1	r	Y	RAX ET AL KIRBY 5-31-73-8	TH	N/A	N	155.63	8760	0	32	1443.57	155.77	0	Y	0.9777	9644.86		
1998/01/21	b	Y	ISH ET AL WINFERED 11-29-73-8	BH	SI/Grad	N	301.1	9999.9	43.51	55.4	1469.49	301.1	0.43	Y	0.9582	9946.32		
1998/05/01	m	Y	RAX ET AL KIRBY 10-33-73-8	BH	N/A	N	154.44	120	0	32	1511.81	154.44	0	Y	0.979	11502.23		
1998/11/05	h	Y	PARA ET AL CLYDE LAKE 10-25-73-9	TH	SI/Grad	N	154.76	123	0	32	1781.5	154.76	0	Y	0.9698	12889.09		
1999/05/15	m	N	RAX ET AL KIRBY 10-33-73-8	BH	N/A	N	0	72	0	32	0	0	0	Y	1	14541.78		
1999/05/15	p	N	RAX ET AL KIRBY 10-33-73-8	BH	N/A	N	0	72	0	32	0	0	0	Y	1	14541.78		
1999/05/15	r	N	RAX ET AL KIRBY 5-31-73-8	BH	N/A	N	0	8760	0	32	0	0	0	Y	1	14541.78		
1999/05/15	s	N	RAX ET AL KIRBY 6-32-73-8	BH	N/A	N	0	8760	0	32	0	0	0	Y	1	14541.78		
1999/11/10	j	Y	PARA ET AL HZ CLYDE LAKE 10-35-73-9	BH	N/A	N	0	27.5	0	32	0	0	0	Y	1	15986.83		
1999/12/10	a	Y	ISH ET AL KIRBY 5-26-73-8	BH	SI/Grad	N	109.5	81.3	105.88	51.8	1553.81	109.5	0	Y	0.9815	16204.84		
2000/02/29	i	Y	PARA ET AL KIRBY 16-27-73-9	BH	SI/Grad	N	145.76	90.3	0	32	1392.72	145.76	0	Y	0.9969	16613.35		
2000/10/02	b	Y	ISH ET AL WINFERED 11-29-73-8	BH	SI/Grad	N	228.14	9999.9	184.2	55.4	1473.76	228.14	0	Y	0.9681	18166.52		
2000/11/06	r	N	RAX ET AL KIRBY 5-31-73-8	BH	N/A	N	0	72	0	32	0	0	0	Y	1	18345.28		
2000/11/06	s	N	RAX ET AL KIRBY 6-32-73-8	BH	N/A	N	0	72	0	32	0	0	0	Y	1	18345.28		
2001/10/24	r	N	RAX ET AL KIRBY 5-31-73-8	BH	N/A	N	0	720	0	32	0	0	0	Y	1	20166.67		
2001/10/24	s	N	RAX ET AL KIRBY 6-32-73-8	BH	N/A	N	0	720	0	32	0	0	0	Y	1	20166.67		
2001/12/03	a	N	ISH ET AL KIRBY 5-26-73-8	BH	N/A	N	0	143.2	0	32	0	0	0	Y	1	20484.3		
2001/12/06	b	Y	ISH ET AL WINFERED 11-29-73-8	BH	SI/Grad	N	372.17	46156.6	13.34	55.4	1472.44	372.17	0	Y	0.9488	20484.3		
2001/12/31	h	Y	PARA ET AL CLYDE LAKE 10-25-73-9	BH	SI/Grad	N	62.66	7664.7	35.53	50	1300.2	62.66	0	Y	0.9907	20484.3		
2003/01/01	e	Y	ISH KIRBY 1-23-74-9	BH	SI/Grad	N	104.28	363	100.95	32	1347.77	104.28	0	Y	0.9824	23505.4		
2003/10/04	a	Y	ISH ET AL KIRBY 5-26-73-8	BH	SI/Grad	N	275.72	3644.4	50.04	32	1551.18	275.72	0	Y	0.9541	23505.4		
2003/12/11	s	Y	PARA ET AL HZ CLYDE LAKE 10-35-73-9	BH	SI/Grad	N	66	81.66	47	59.47	55.4	1400.59	81.66	0	Y	0.9983	23742.09	
2004/01/19	n	Y	RAX ET AL KIRBY 1-6-74-8	BH	SI/Grad	N	77.89	3361.9	74.26	59	1437.01	77.89	0	Y	0.989	23863.76		
2004/01/20	r	Y	RAX ET AL KIRBY 5-31-73-8	BH	SI/Grad	N	74.84	3385.4	70.78	55.4	1427.49	74.84	0	Y	0.9892	23863.76		
2004/02/25	i	Y	PARA ET AL KIRBY 16-27-73-9	BH	SI/Grad	N	165.78	26075.6	0	57.2	1392.72	165.78	0	Y	0.9969	23979.27		

Deliverability Tests

Date	ym/d	Symbol	Use	Well Name	Test	Type	Duration	Water				Flow	MPP	Pressure	N	AOPF	Calc	Z	CumGas	Upper Perf. Depth	Lower Part. Depth	Liquids per Day	Choke	Sediment and Water %	C Factor	Liquid Gravity	Oil Gravity	Water Gravity
								Rate	Oil Flow	Flow	Rate																	
1981/01/26	a	Y	ISH ET AL KIRBY 5-26-73-8	N/A																								

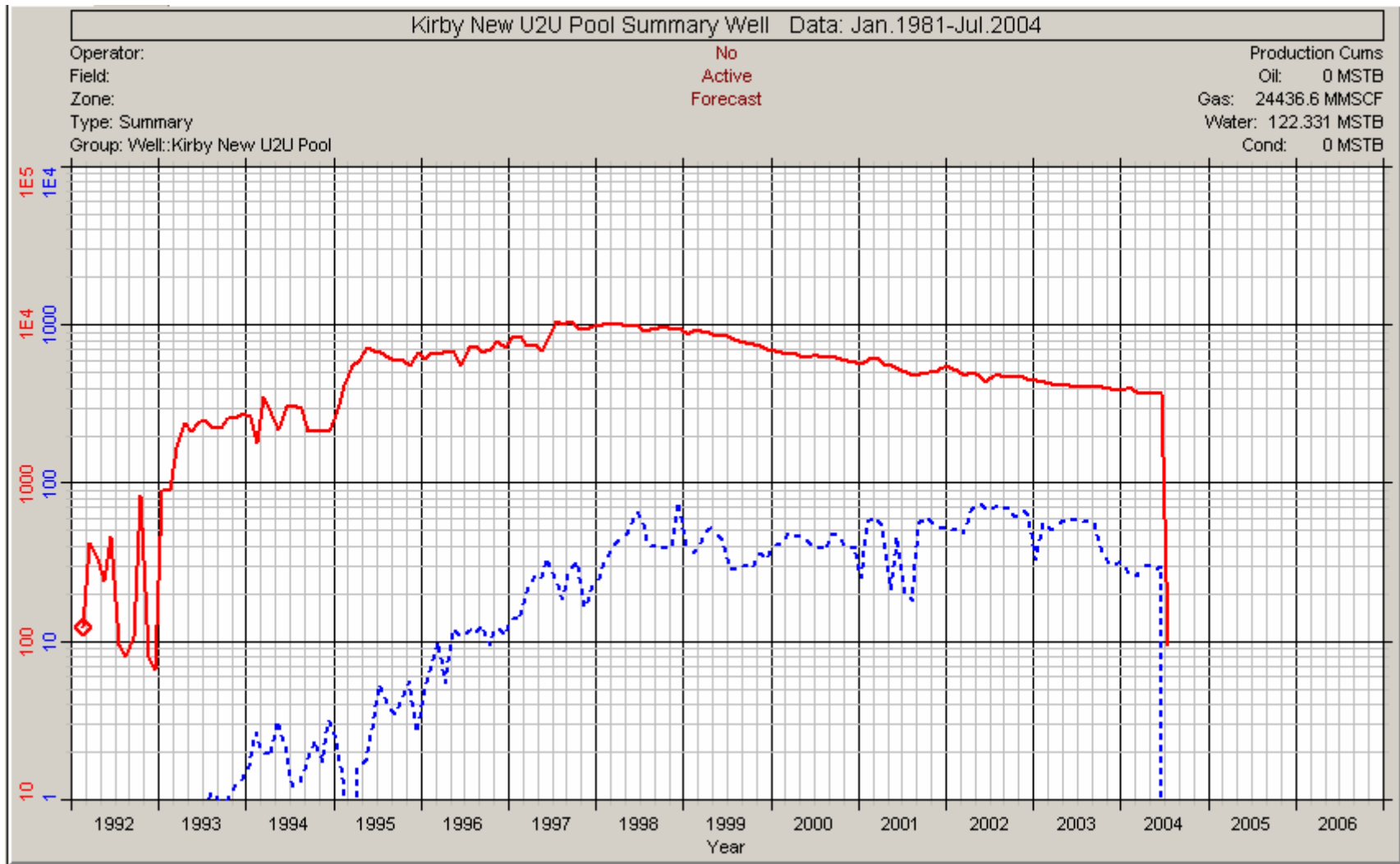


Figure 10. CNRL revised U2U Pool Production Plot

Figure 11
RGS Bitumen Evaluation Data for Proposed Pool

Revised Kirby Upper Mannville J Pool				
Revised Pool Name	SSG Pool Name	Well ID	Gross Interval	Net Interval
UPPER MANNVILLE J	UPPER MANNVILLE J	00/10-05-073-07W4/0	12.3	7.5
UPPER MANNVILLE J	UPPER MANNVILLE J	00/11-07-073-07W4/0	16.15	14.05
UPPER MANNVILLE J	UPPER MANNVILLE J	00/07-19-073-07W4/0	18	14.7
UPPER MANNVILLE J	UPPER MANNVILLE J	00/10-03-073-08W4/0	#N/A	#N/A
UPPER MANNVILLE J	UPPER MANNVILLE J	00/10-08-073-08W4/0	6.3	6.3
UPPER MANNVILLE J	UPPER MANNVILLE J	00/06-09-073-08W4/0	3.6	3.6
UPPER MANNVILLE J	UPPER MANNVILLE J	00/06-10-073-08W4/0	1.39	1.09
UPPER MANNVILLE J	UPPER MANNVILLE J	00/10-13-073-08W4/0	18.3	15.59
UPPER MANNVILLE J	UPPER MANNVILLE J	00/11-14-073-08W4/0	10.75	10.75
UPPER MANNVILLE J	UPPER MANNVILLE J	00/10-15-073-08W4/0	12	9.3
UPPER MANNVILLE J	UPPER MANNVILLE J	00/09-17-073-08W4/0	#N/A	#N/A
UPPER MANNVILLE J	UPPER MANNVILLE J	00/10-17-073-08W4/0	9.89	5.99
UPPER MANNVILLE J	UPPER MANNVILLE J	00/15-18-073-08W4/0	6.6	4.2
UPPER MANNVILLE J	UPPER MANNVILLE J	00/09-19-073-08W4/0	3.89	1.79
UPPER MANNVILLE J	UPPER MANNVILLE J	00/16-20-073-08W4/0	10.49	8.39
UPPER MANNVILLE J	UPPER MANNVILLE J	00/16-21-073-08W4/0	12	9.6
UPPER MANNVILLE J	UPPER MANNVILLE J	00/16-22-073-08W4/0	12.6	11.7
UPPER MANNVILLE J	UPPER MANNVILLE J	00/16-23-073-08W4/0	15.9	15.9
UPPER MANNVILLE J	UPPER MANNVILLE J	00/10-24-073-08W4/0	14.1	12.89
UPPER MANNVILLE J	UPPER MANNVILLE J	00/01-25-073-08W4/0	18.6	15.9

Figure 12
RGS Bitumen Evaluation Data for Proposed Pool

Revised Kirby Upper Mannville U2U Pool				
Revised Pool Name	SSG Pool Name	Well ID	Gross Interval	Net Interval
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/05-26-073-08W4/0	14.25	10.35
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/11-27-073-08W4/0	13.19	11.69
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/10-29-073-08W4/0	#N/A	#N/A
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/11-29-073-08W4/0	10.65	9.75
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/10-30-073-08W4/0	14.69	10.79
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/05-31-073-08W4/0	14.09	8.69
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/14-31-073-08W4/0	#N/A	#N/A
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/06-32-073-08W4/0	16.5	6.9
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/10-33-073-08W4/0		
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	02/10-33-073-08W4/0	12	9.6
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/02-25-073-09W4/0	5.1	4.5
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/10-25-073-09W4/0	#N/A	#N/A
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/16-27-073-09W4/0	6.89	4.49
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/09-35-073-09W4/0	#N/A	#N/A
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/10-35-073-09W4/0	#N/A	#N/A
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/07-36-073-09W4/0	11.4	9
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/10-36-073-09W4/0	#N/A	#N/A
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/03-05-074-08W4/0	13.8	12.6
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/01-06-074-08W4/0	15.6	11.1
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/06-06-074-08W4/0	12	1.5
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/11-01-074-09W4/0	9.14	7.94
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/10-02-074-09W4/0	6.9	4.5
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/09-03-074-09W4/0	2.69	1.49
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/10-11-074-09W4/0	6	6
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/10-14-074-09W4/0	8.99	2.39
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	02/10-14-074-09W4/0	#N/A	#N/A
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/01-23-074-09W4/0	0.29	0.29
UPPER MANNVILLE U2U	UPPER MANNVILLE U2U	00/04-24-074-09W4/0	8.39	5.7
UPPER MANNVILLE U2U	UPPER MANNVILLE B4B	00/06-34-073-08W4/0	16.5	14.4
UPPER MANNVILLE U2U	UPPER MANNVILLE B4B	00/09-34-073-08W4/0	12.9	11.1
UPPER MANNVILLE U2U	UPPER MANNVILLE B4B	00/10-34-073-08W4/0	#N/A	#N/A
UPPER MANNVILLE U2U	UPPER MANNVILLE B4B	00/11-34-073-08W4/0	#N/A	#N/A
UPPER MANNVILLE U2U	UPPER MANNVILLE B4B	00/04-03-074-08W4/0	14.1	12

00/10-34-073-08W4/3

KB: 704.4 m
TD: 556.0 m
Mode: Susp
RAX NCR KIRBY 10-34-73-8

RR: 1981-02-16
FormTD: BHL
Fluid: Gas

187.0m to next well >

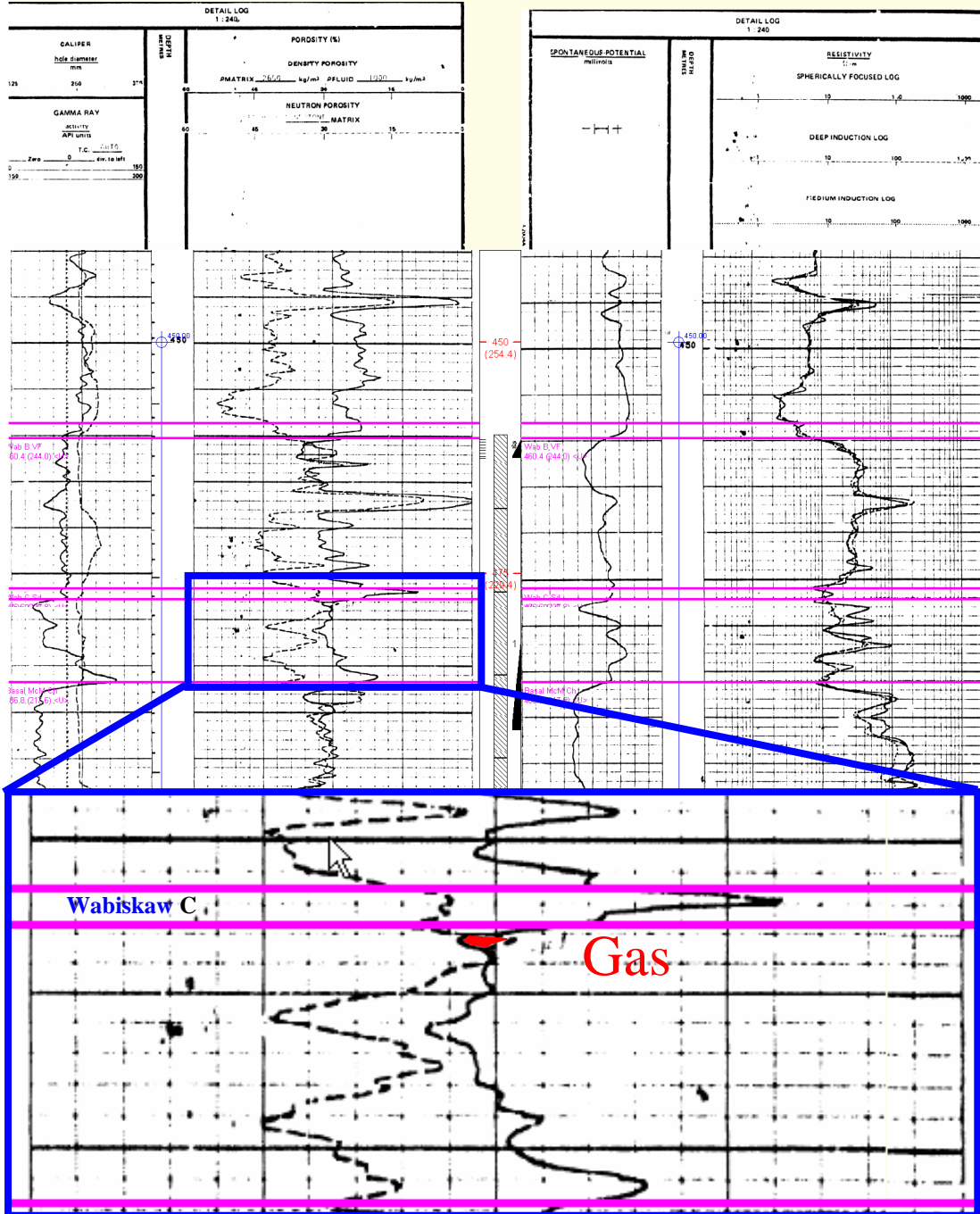


Figure 15. Top Gas, Proof of Wabiskaw C Seal Capacity, U2U Pool.

00/09-34-073-08W4/0

KB: 706.4 m RR: 1997-03-04
TD: 555.0 m FormTD: BHL
Mode: Susp Fluid: Water
RAX KIRBY 9-34-73-8

< 187.0m to previous well

1006.2m to next well >

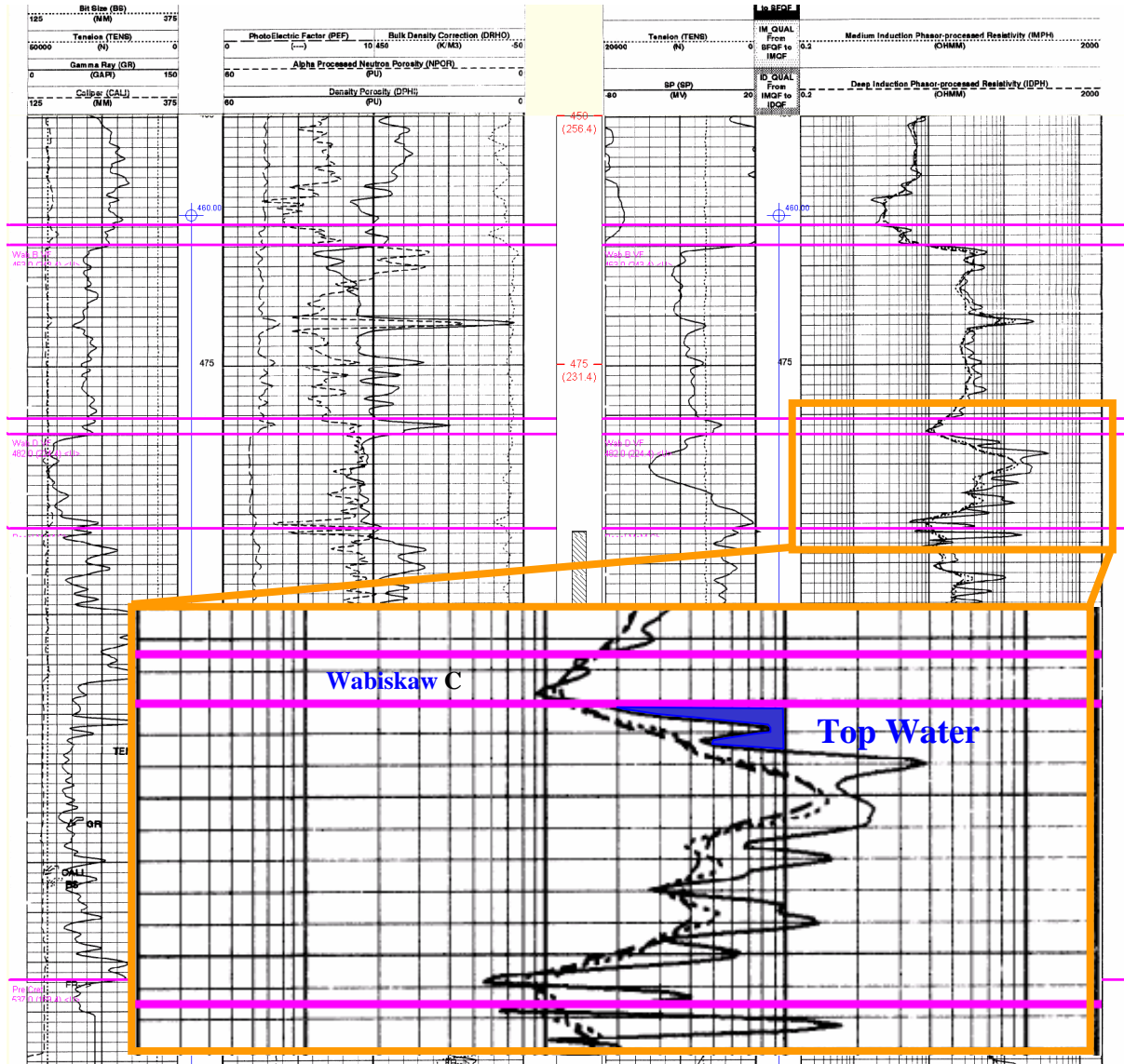


Figure 16. Top Water, Proof of Wabiskaw C Seal Capacity, U2U Pool

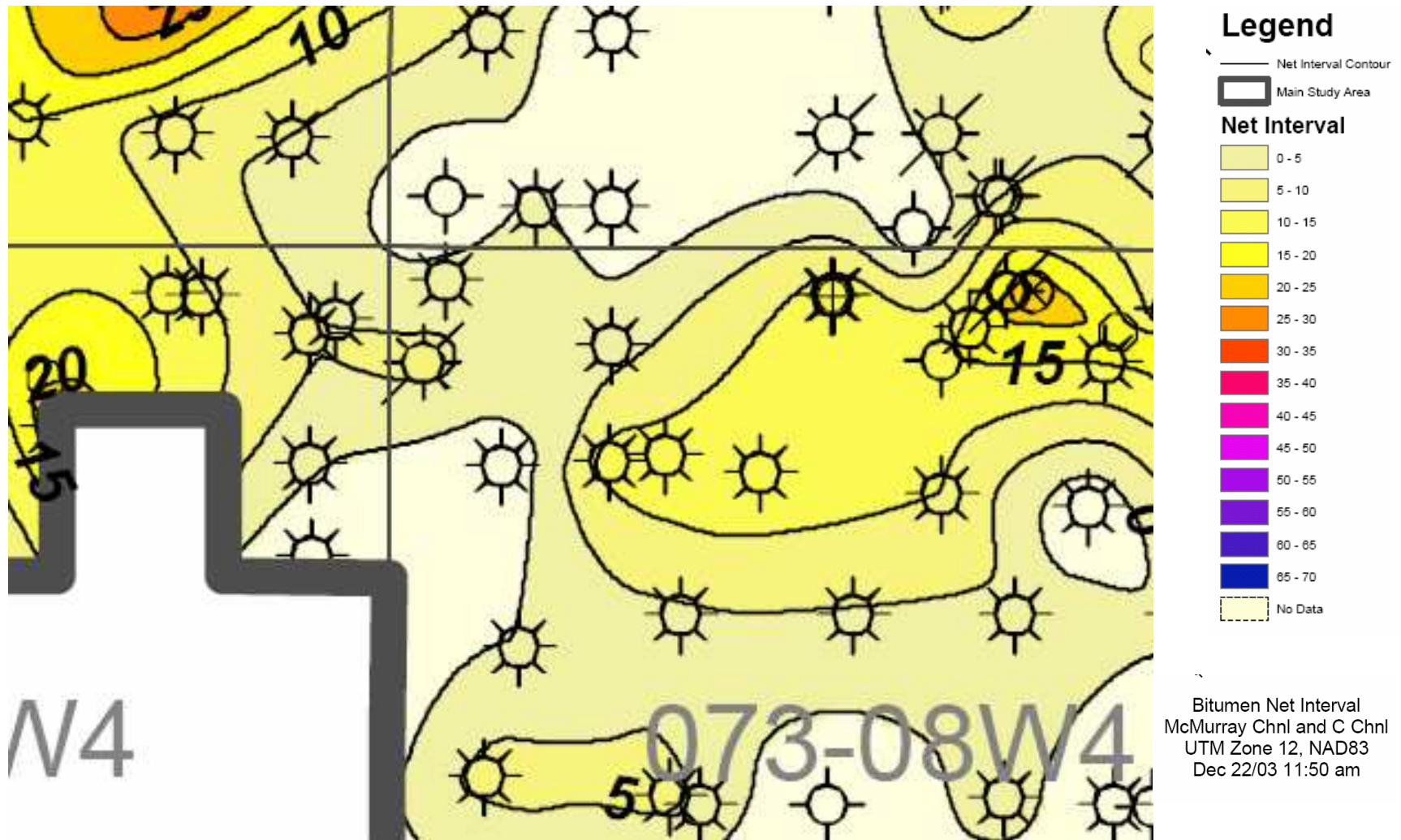


Figure 17. Excerpt Net McMurray Channel Bitumen Pay Map from RGS

Figure 18
RGS Bitumen Evaluation Data for Proposed Pool

Revised Kirby Upper Mannville V2V Pool				
Revised Pool Name	SSG Pool Name	Well ID	Gross Interval	Net Interval
SINGLE WELL POOL	UPPER MANNVILLE V2V	00/12-16-074-07W4/0	15.9	13.8
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/10-18-074-07W4/0	15.9	13.2
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/14-18-074-07W4/0	#N/A	#N/A
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/05-19-074-07W4/0	12.3	10.2
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/10-01-074-08W4/0	19	17.79
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/07-07-074-08W4/0	12.44	10.64
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/06-08-074-08W4/0	12.6	7.2
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/10-09-074-08W4/0	14.1	10.2
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/11-10-074-08W4/0	13.8	13.8
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/02-11-074-08W4/0	18.5	15.5
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/10-11-074-08W4/0	15.6	13.8
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/12-11-074-08W4/0	15.75	14.85
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/09-12-074-08W4/0	17.15	13.85
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/14-12-074-08W4/0	15	13.8
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/10-13-074-08W4/0	12.3	9.3
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/11-13-074-08W4/0	13.5	7.8
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/13-13-074-08W4/0	15.75	13.34
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/09-14-074-08W4/0	14.4	11.99
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/10-14-074-08W4/0	13.2	7.5
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/11-14-074-08W4/0	10.2	6.6
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/12-14-074-08W4/0	13.5	9.9
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/15-14-074-08W4/0	#N/A	#N/A
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/16-14-074-08W4/0	13.15	10.15
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/06-15-074-08W4/0	16.8	12.59
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/01-16-074-08W4/0	14.35	13.75
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/01-17-074-08W4/0	13.55	12.34
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/10-17-074-08W4/0	14.09	10.19
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/01-18-074-08W4/0	13.05	10.05
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/02-19-074-08W4/0	6.6	5.1
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/09-20-074-08W4/0	6.29	4.8
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/11-22-074-08W4/0	10.8	2.4
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/12-23-074-08W4/0	11.35	7.75
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/06-24-074-08W4/0	12	10.2
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/10-12-074-09W4/0	12.3	8.39
UPPER MANNVILLE V2V	UPPER MANNVILLE V2V	00/10-13-074-09W4/0	11.8	6.69

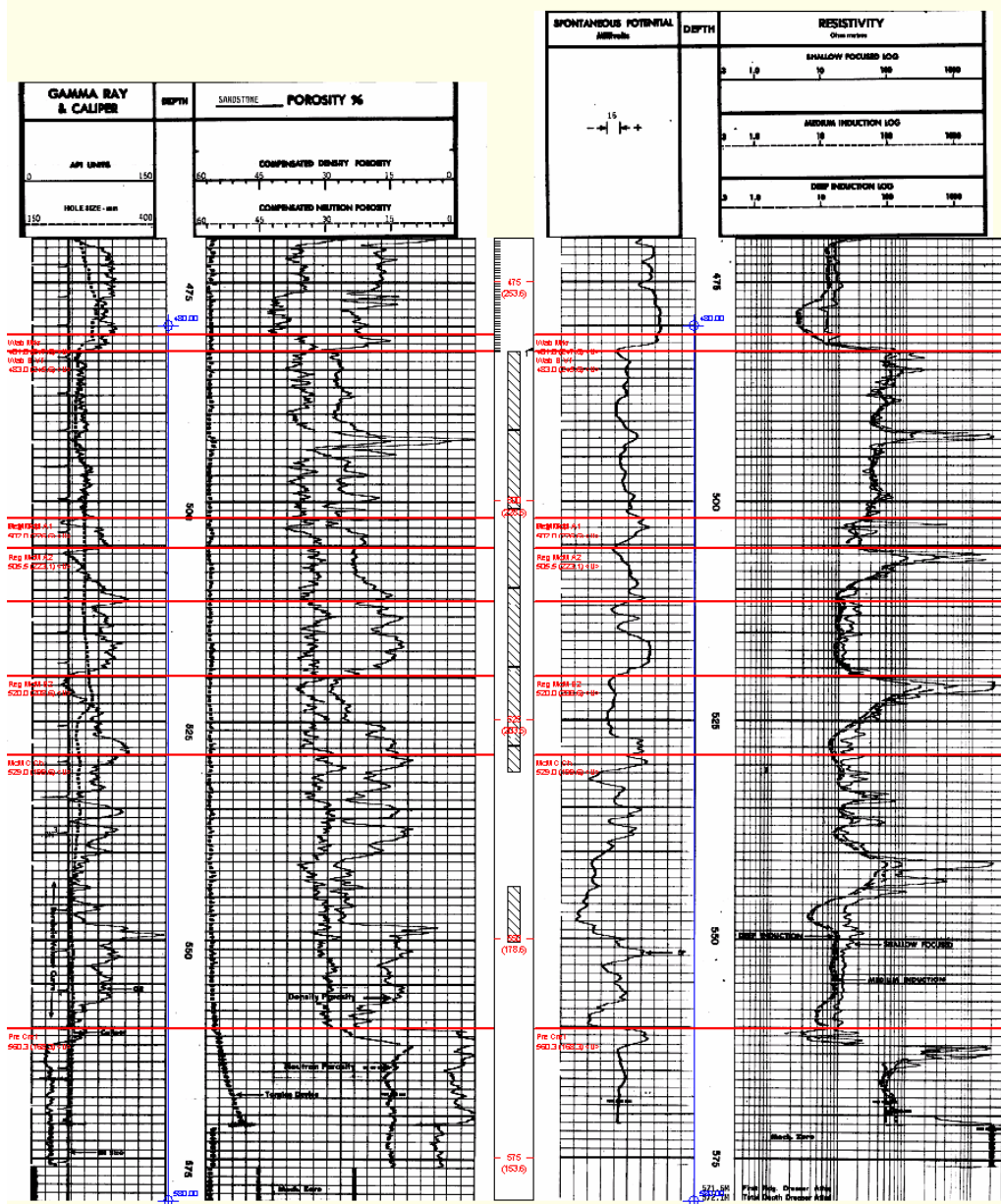
Figure 19
10-01-074-08w4 Core Analysis Data

Location	S#	Sample Top (m)	Thickness (m)	Porosity	RSat Oil Ratio	RSat Wtr Ratio	Lithology	Thickness of Sample >50% Saturation
00/10-01-074-08W4/0	1	483	1	0	0	0	NOT ANALYSED - SHALE	
00/10-01-074-08W4/0	2	484	0.28	0.306	0.203	0.797	SS VF SLT CARB	
00/10-01-074-08W4/0	3	484.28	0.3	0.308	0.222	0.778	SS VF SLT	
00/10-01-074-08W4/0	4	484.58	0.27	0.331	0.519	0.481	SS VF SLT	0.27
00/10-01-074-08W4/0	5	484.85	0.3	0.381	0.661	0.339	SS VF SLT	0.3
00/10-01-074-08W4/0	6	485.15	0.3	0.349	0.775	0.225	SS VF SLT	0.3
00/10-01-074-08W4/0	7	485.45	0.29	0.341	0.701	0.299	SS VF SLT CARB	0.29
00/10-01-074-08W4/0	8	485.74	0.3	0.359	0.554	0.446	SS VF ARGLSLT	0.3
00/10-01-074-08W4/0	9	486.04	0.28	0.373	0.685	0.315	SS VF SLT	0.28
00/10-01-074-08W4/0	10	486.32	0.3	0.321	0.533	0.467	SS VF ARGLSLT	0.3
00/10-01-074-08W4/0	11	486.62	0.3	0.351	0.729	0.271	SS VF SLT	0.3
00/10-01-074-08W4/0	12	486.92	0.29	0.344	0.765	0.235	SS VF SLT	0.29
00/10-01-074-08W4/0	13	487.21	0.31	0.338	0.728	0.272	SS VF ARGLSLT CARB	0.31
00/10-01-074-08W4/0	14	487.52	0.28	0.346	0.784	0.216	SS VF SLT	0.28
00/10-01-074-08W4/0	15	487.8	0.31	0.34	0.65	0.35	SS VF ARGLSLT	0.31
00/10-01-074-08W4/0	16	488.11	0.3	0.353	0.766	0.234	SS VF ARGLSLT	0.3
00/10-01-074-08W4/0	17	488.41	0.28	0.356	0.659	0.341	SS VF ARGLSLT CARB	0.28
00/10-01-074-08W4/0	18	488.69	0.3	0.354	0.674	0.326	SS VF ARGLSLT	0.3
00/10-01-074-08W4/0	19	488.99	0.29	0.349	0.734	0.266	SS VF SLT	0.29
00/10-01-074-08W4/0	20	489.28	0.31	0.318	0.6	0.4	SS VF ARGLSLT	0.31
00/10-01-074-08W4/0	21	489.59	0.31	0.367	0.661	0.339	SS VF SLT	0.31
00/10-01-074-08W4/0	22	489.9	2.1	0	0	0	LOST CORE	
00/10-01-074-08W4/0	1	492	0.3	0.37	0.604	0.396	SS VF SLT	0.3
00/10-01-074-08W4/0	2	492.3	0.3	0.349	0.663	0.337	SS VF SLT	0.3
00/10-01-074-08W4/0	3	492.6	0.27	0.341	0.634	0.366	SS VF SLT	0.27
00/10-01-074-08W4/0	4	492.87	0.3	0.333	0.591	0.409	SS VF SLT CARB	0.3
00/10-01-074-08W4/0	5	493.17	0.3	0.018	0	0	SS VF SLT	
00/10-01-074-08W4/0	6	493.47	0.3	0.32	0.589	0.411	SS VF SLT	0.3
00/10-01-074-08W4/0	7	493.77	0.21	0.294	0.618	0.382	SS VF SLT	0.21
00/10-01-074-08W4/0	8	493.98	0.24	0.164	0.507	0.493	SS VF SLT	0.24
00/10-01-074-08W4/0	9	494.22	1	0	0	0	NOT ANALYSED - DENSE	
00/10-01-074-08W4/0	10	495.22	0.3	0.326	0.606	0.394	SS VF	0.3
00/10-01-074-08W4/0	11	495.52	0.3	0.338	0.593	0.407	SS VF SLT	0.3
00/10-01-074-08W4/0	12	495.82	0.28	0.335	0.563	0.437	SS VF CARB	0.28
00/10-01-074-08W4/0	13	496.1	0.22	0	0	0	NOT ANALYSED - DENSE	
00/10-01-074-08W4/0	14	496.32	0.31	0.351	0.606	0.394	SS VF	0.31

00/10-01-074-08W4/0	15	496.63	0.3	0.349	0.621	0.379	SS VF	0.3
00/10-01-074-08W4/0	16	496.93	0.25	0.341	0.591	0.409	SS VF	0.25
00/10-01-074-08W4/0	17	497.18	0.3	0.356	0.566	0.434	SS VF	0.3
00/10-01-074-08W4/0	18	497.48	0.31	0.364	0.522	0.478	SS VF ARGL	0.31
00/10-01-074-08W4/0	19	497.79	0.25	0.373	0.489	0.511	SS VF	
00/10-01-074-08W4/0	20	498.04	0.3	0.343	0.582	0.418	SS VF	0.3
00/10-01-074-08W4/0	21	498.34	0.31	0.295	0.511	0.489	SS VF SLT CARB	0.31
00/10-01-074-08W4/0	22	498.65	0.3	0.336	0.59	0.41	SS VF	0.3
00/10-01-074-08W4/0	23	498.95	0.3	0.367	0.517	0.483	SS VF	0.3
00/10-01-074-08W4/0	24	499.25	0.27	0.354	0.576	0.424	SS VF	0.27
00/10-01-074-08W4/0	25	499.52	0.34	0.344	0.56	0.44	SS VF	0.34
00/10-01-074-08W4/0	26	499.86	0.32	0.348	0.452	0.548	SS VF ARGL	
00/10-01-074-08W4/0	27	500.18	0.27	0.353	0.614	0.386	SS VF	0.27
00/10-01-074-08W4/0	28	500.45	0.55	0	0	0	LOST CORE	
00/10-01-074-08W4/0	1	501	0.3	0.263	0.613	0.387	SS VF ARGL	0.3
00/10-01-074-08W4/0	2	501.3	0.3	0.25	0.661	0.339	SS VF	0.3
00/10-01-074-08W4/0	3	501.6	0.27	0.294	0.588	0.412	SS VF	0.27
00/10-01-074-08W4/0	4	501.87	0.31	0.357	0.615	0.385	SS VF	0.31
00/10-01-074-08W4/0	5	502.18	0.31	0.368	0.541	0.459	SS VF	0.31
00/10-01-074-08W4/0	6	502.49	0.31	0.354	0.5	0.5	SS VF ARGL	0.31
00/10-01-074-08W4/0	7	502.8	0.2	0.367	0.55	0.45	SS VF CARB	0.2
		Total core cut	19				Total Thickness >50% Sat	13.68

00/10-01-074-08W4/0

KB: 728.6 m RR: 1982-01-21
 TD: 573.0 m Mode: Abnd Fluid: N/A
 FormTD: BHL
 RAX NCR KIRBY 10-1-74-8



DST Information

1. 482.5-483.0 (McM Top)
 Type: IP - PRODUCTION
 VO: 0.0/0.0 SI: 0.0/0.0 min
 FP: 1048.0/1048.0 kPa
 SIP: 1131.0/1131.0 kPa
 HP: 0.0/0.0 kPa
 GTS MAX 3900 M3/D (. 137 MMCF/D); VO 14. HRS, 4.76 MM OR, DD 25.6 t;

Prod	Oil (m3)	Gas (E3m3)	Water (m3)
Cum	0.0	0.0	0.0
Daily	0.0	0.0	0.0

Figure 20

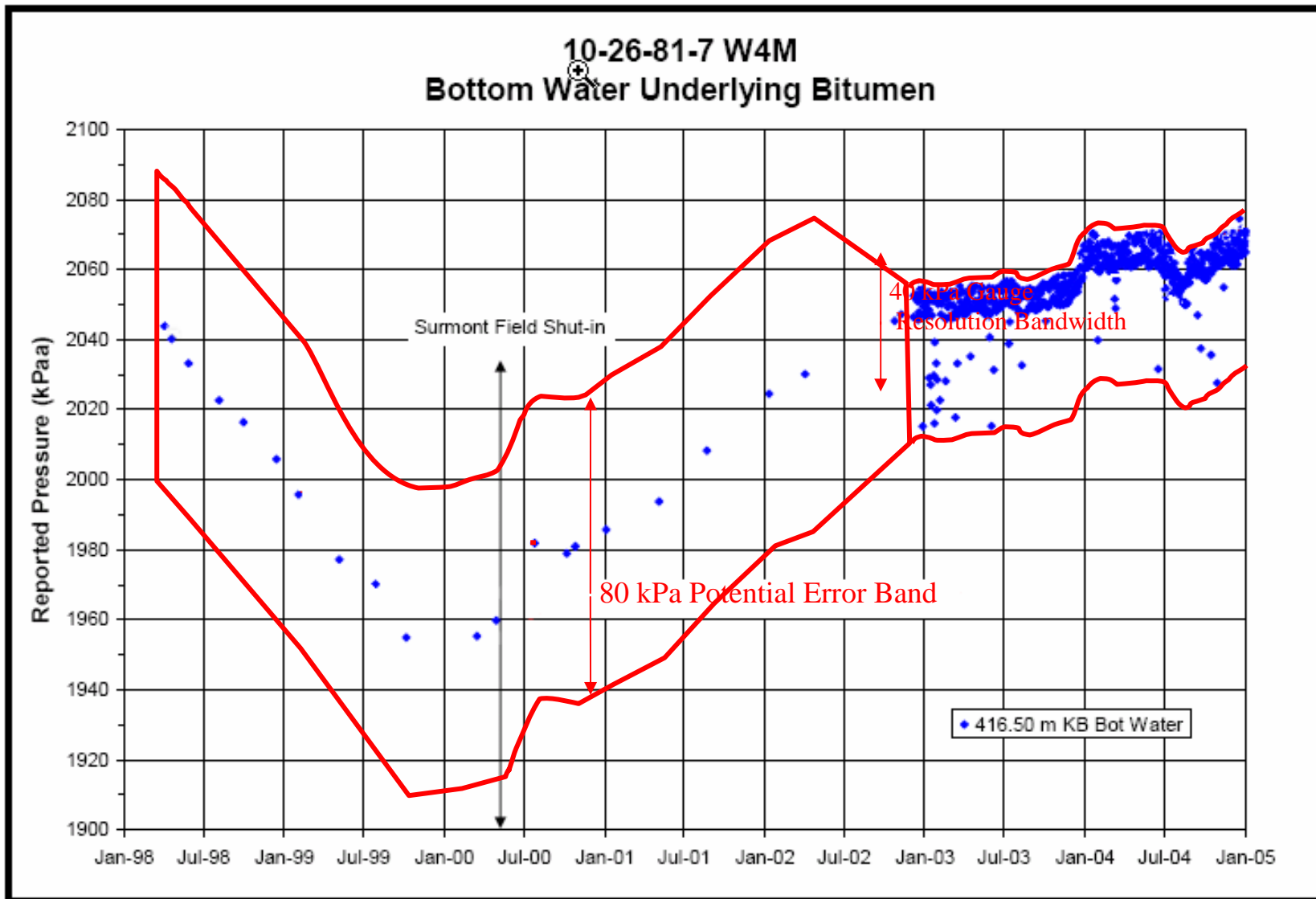


Figure 22. Modified Pressure Plot 10-26-81-7W4

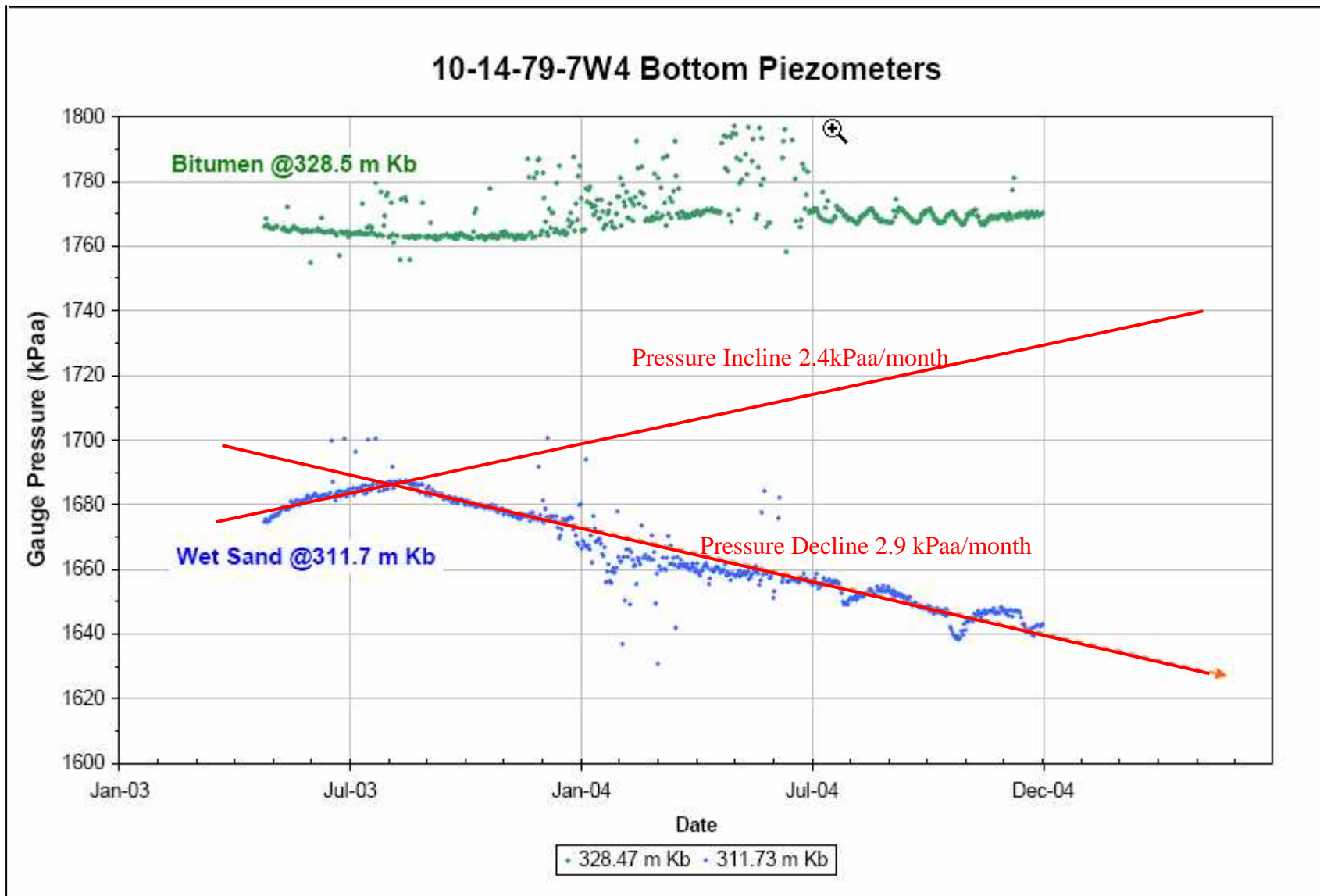


Figure 23. CNRL Modified Piezometer Plot for 10-14-79-7W4

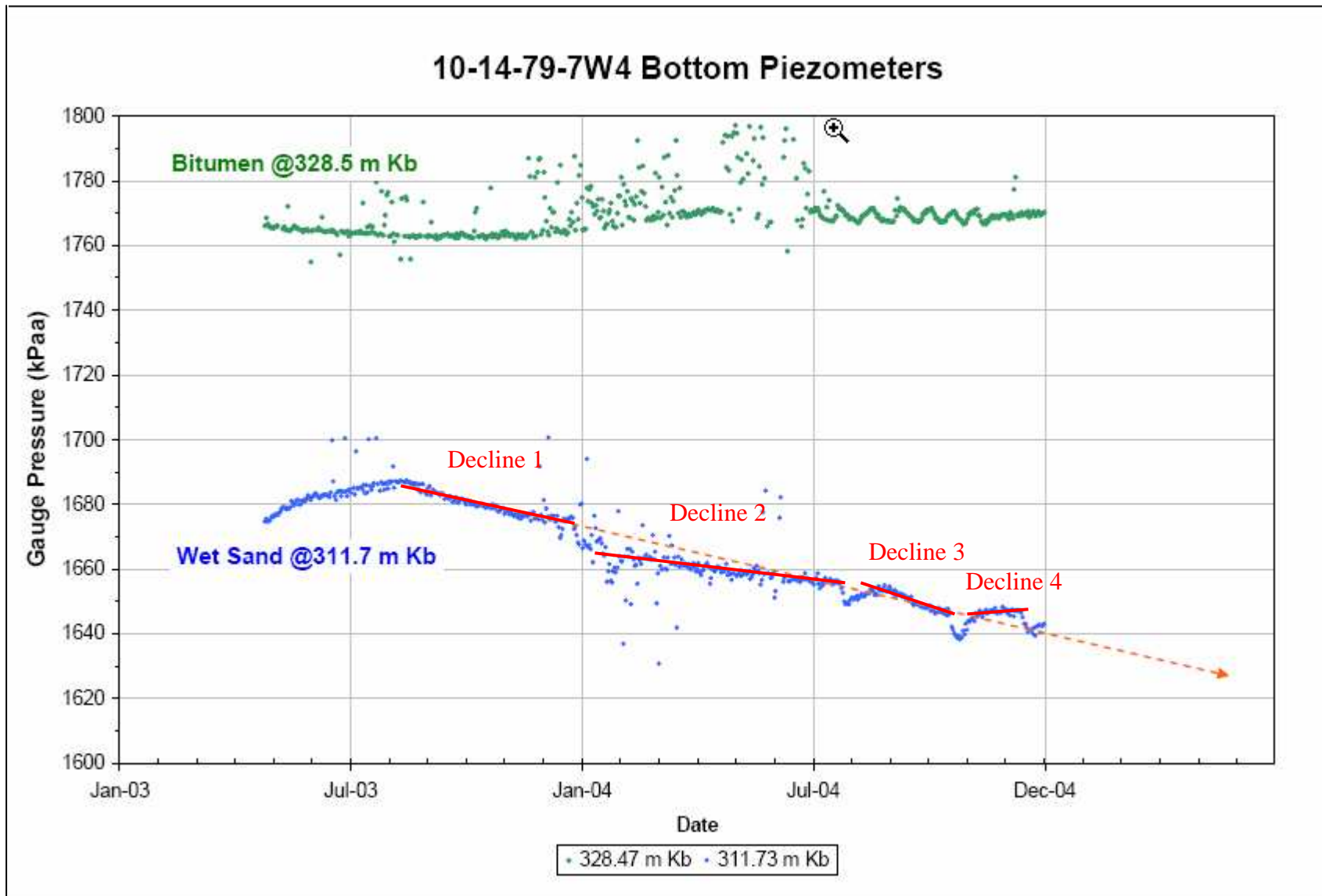


Figure 24. Piezometer Pressure Plot 10-14-79-7W4

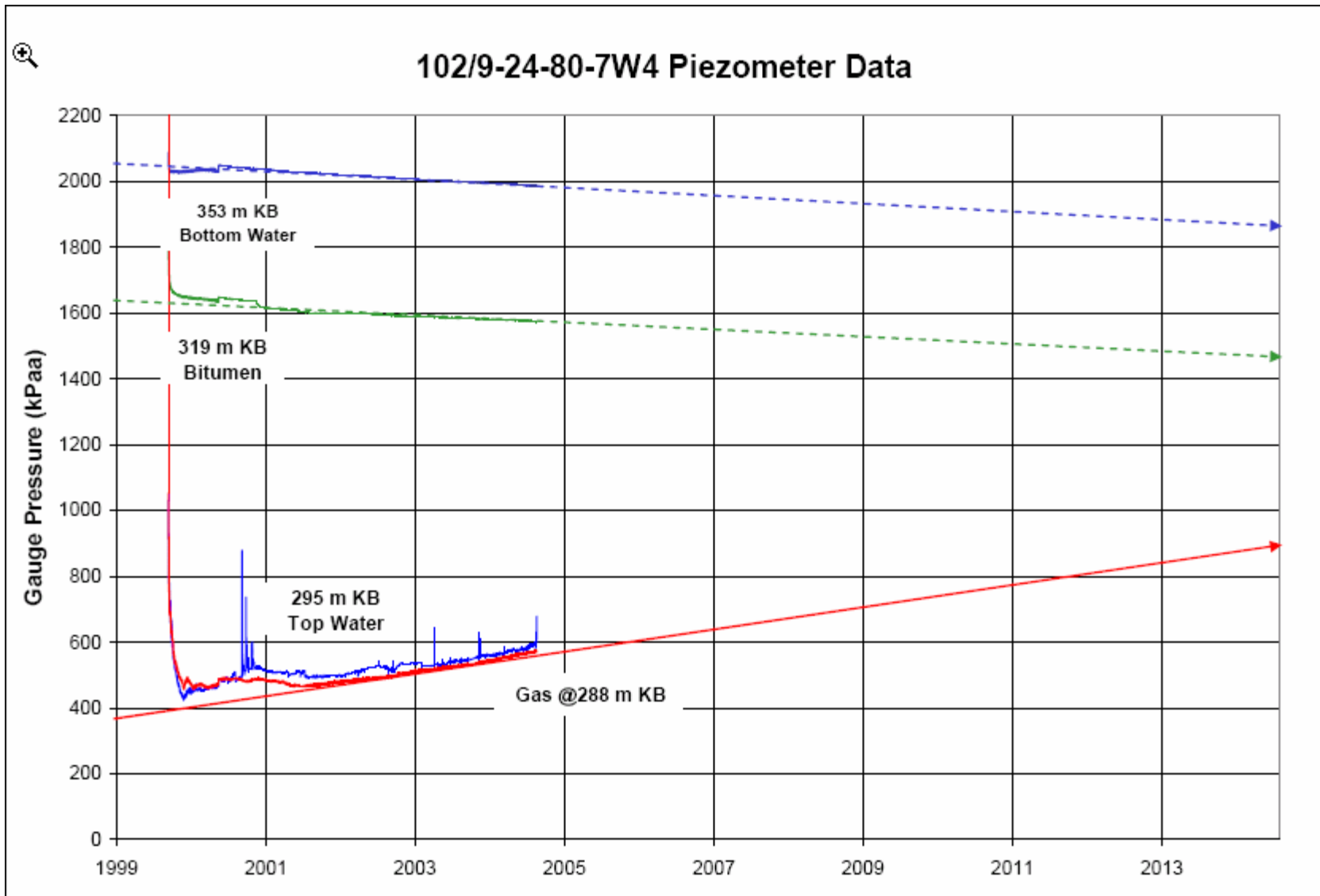


Figure 25. Piezometer Pressure Plot 9-24-80-7W4

Figure 26

Presence / Absence Comparison

Well ID	Nexen Core Measured Thickness (m)	SSG Core Measured Thickness (m)
AA/12-18-085-06W4/0	0.32	0.0
AA/09-19-085-06W4/0	0.29	0.0
AA/02-29-085-06W4/0	0.47	0.0
AA/09-30-085-06W4/0	0.25	0.0
AA/04-31-085-06W4/0	0.24	0.0
AA/14-13-085-07W4/0	0.31	0.0
AA/06-24-085-07W4/0	0.41	0.0
AA/09-24-085-07W4/0	0.26	0.0
AA/14-24-085-07W4/0	0.21	0.0
AA/11-25-085-07W4/0	0.39	0.0
AA/04-36-085-07W4/0	0.33	0.0
AA/06-06-086-06W4/0	0.19	0.0
AA/08-06-086-06W4/0	0.21	0.0
AA/04-01-086-07W4/0	0.31	0.0
AA/11-01-086-07W4/0	0.27	0.0
AA/16-11-086-07W4/0	0.21	0.0
AA/02-12-086-07W4/0	0.27	0.0
AA/10-22-086-07W4/0	0.31	0.0
AA/06-23-086-07W4/0	0.52	0.0
AA/09-23-086-07W4/0	0.26	0.0
AA/02-24-086-07W4/0	0.18	0.0
AA/04-24-086-07W4/0	0.4	0.0
AA/10-27-086-07W4/0	0.3	0.0
AA/06-28-086-07W4/0	0.57	0.0
AA/07-33-086-07W4/0	0.22	0.0
AA/07-34-086-07W4/0	0.2	0.0
AA/08-35-086-07W4/0	0.26	0.0

Figure 27

Measured Core Thickness Comparison

Well ID	Nexen Core	SSG Core
	Measured Thickness	Measured Thickness
AA/01-32-084-07W4/0	0.40	0.76
AA/06-34-084-07W4/0	0.36	1.20
AA/05-30-085-06W4/0	0.47	1.30
AA/08-36-086-07W4/0	0.18	0.07

Figure 28
Lost Core in SSG Study

Well ID	Unit Identified in Core	SSG Core Thickness (m)	Reported Lost Core
00/10-26-075-05W4/0	Wabiskaw D Shale	0.07	
AA/08-36-086-07W4/0	Wabiskaw D Shale	0.07	
AA/16-13-084-09W4/0	Wabiskaw D Shale	0.12	
AA/02-09-085-08W4	Wabiskaw D Shale	0.15	
AA/10-24-085-10W4/0	Wabiskaw D Shale	0.17	
AA/09-07-085-10W4/0	Wabiskaw D Shale	0.22	
AA/16-30-085-08W4/0	Wabiskaw D Shale	0.14	yes
AA/11-17-085-10W4/0	Wabiskaw D Shale	0.23	
AA/10-05-085-08W4/0	Wabiskaw D Shale	0.17	yes
AA/09-04-085-08W4/0	Wabiskaw D Shale	0.22	yes
AA/11-11-086-07W4/0	Wabiskaw D Shale	0.28	
AA/09-29-084-07W4/0	Wabiskaw D Shale	0.30	
AA/02-20-086-08W4/0	Wabiskaw D Shale	0.23	yes
AA/10-03-080-07W4/0	Wabiskaw D Shale	0.20	yes
AA/07-20-086-07W4/0	Wabiskaw D Shale	0.34	yes
AA/09-36-084-12W4/0	Wabiskaw D Shale	0.43	
AA/05-16-085-06W4/0	Wabiskaw D Shale	0.33	yes
00/10-08-084-09W4/0	Wabiskaw D Shale	0.53	yes
00/15-35-076-04W4/0	Wabiskaw D Shale	0.53	
AA/05-31-084-07W4/0	Wabiskaw D Shale	0.54	yes
00/10-08-076-05W4/0	Wabiskaw D Shale	0.25	yes
AA/13-06-083-08W4/0	Wabiskaw D Shale	0.56	yes
AA/16-04-086-08W4/0	Wabiskaw D Shale	0.49	yes
AA/14-25-086-07W4/0	Wabiskaw D Shale	0.08	yes
AA/10-10-080-07W4/0	Wabiskaw D Shale	0.25	yes
AA/14-36-083-08W4/0	Wabiskaw D Shale	0.63	yes
AA/13-11-084-09W4/0	Wabiskaw D Shale	0.69	
AA/16-17-084-09W4/0	Wabiskaw D Shale	0.70	
00/05-18-084-08W4/0	Wabiskaw D Shale	0.23	yes
AA/16-18-084-09W4/0	Wabiskaw D Shale	0.75	yes
00/11-14-077-06W4/0	Wabiskaw D Shale	0.75	yes
AA/01-17-086-08W4/0	Wabiskaw D Shale	0.65	yes
AA/01-32-084-07W4/0	Wabiskaw D Shale	0.76	yes
AA/02-27-084-09W4/0	Wabiskaw D Shale	0.53	yes
AA/10-22-080-07W4/0	Wabiskaw D Shale	0.83	
AA/08-04-084-09W4/0	Wabiskaw D Shale	0.84	yes
AA/16-14-083-08W4/0	Wabiskaw D Shale	0.85	
AA/13-20-084-09W4/0	Wabiskaw D Shale	1.00	
00/09-36-077-06W4/0	Wabiskaw D Shale	0.75	yes
00/10-02-082-05W4/0	Wabiskaw D Shale	1.00	yes
00/03-34-080-08W4/0	Wabiskaw D Shale	0.70	yes
AA/15-10-084-09W4/0	Wabiskaw D Shale	1.01	
AA/01-15-085-08W4/0	Wabiskaw D Shale	1.03	

00/07-15-084-09W4/0	Wabiskaw D Shale	1.07	yes
AA/06-18-084-07W4/0	Wabiskaw D Shale	0.85	yes
AA/10-29-080-07W4/0	Wabiskaw D Shale	1.20	yes
AA/02-30-085-06W4/0	Wabiskaw D Shale	1.27	
AA/05-30-085-06W4/0	Wabiskaw D Shale	1.30	yes
00/03-32-080-07W4/0	Wabiskaw D Shale	1.43	
AA/10-26-080-07W4/0	Wabiskaw D Shale	1.14	yes
AA/06-34-084-07W4/0	Wabiskaw D Shale	1.20	yes
00/07-13-077-06W4/0	Wabiskaw D Shale	0.47	yes
AA/11-30-080-06W4/0	Wabiskaw D Shale	1.52	
AA/07-26-080-08W4/0	Wabiskaw D Shale	0.14	yes
02/09-24-080-07W4/0	Wabiskaw D Shale	1.80	
AA/12-09-085-06W4/0	Wabiskaw D Shale	1.90	
00/07-33-081-05W4/0	Wabiskaw D Shale	2.15	
00/10-30-080-06W4/0	Wabiskaw D Shale	2.20	yes
AA/06-10-084-09W4/0	Wabiskaw D Shale	2.38	
00/10-04-073-07W4/0	Wabiskaw D Shale	2.00	yes

Figure 29
Excerpt from SSG Appendix 1, Contested Wells & Intervals
(Core Column Added by CNRL)

Field Name	Pool Name	Well ID	Stratigraphic Interval	Change in Pay Intervals for Final Hearing	SSG Previous Produce / Shut in	SSG New Produce / Shut in	Decision 2004-045	Licensee	Cored
CHARD	WABISKAW U/D-034	00/06-20-080-06W4/0	Wbsk C Sand		Produce	Shut-In		CNRL	No
CHARD	WABISKAW K	00/11-28-080-06W4/0	Wbsk C Sand		Produce	Shut-In		CNRL	No
CHARD	WABISKAW U/D-037	00/07-13-080-07W4/0	Wbsk C Sand		Produce	Shut-In		CNRL	No
CHARD	WABISKAW U/D-037	00/07-14-080-07W4/0	Wbsk C Sand		Produce	Shut-In		CNRL	No
CHARD	WABISKAW U/D-037	00/10-23-080-07W4/0	Wbsk C Sand		Produce	Shut-In		CNRL	No
NEWBY	WABISKAW AA	00/14-20-083-05W4/0	Wbsk C Sand		Produce	Shut-In		CNRL	No
NEWBY	WABISKAW AA	00/06-30-083-05W4/0	Wbsk C Sand		Produce	Shut-In		CNRL	No
NEWBY	WABISKAW U/D-060	00/15-31-083-05W4/0	Wbsk C Sand		Produce	Shut-In		CNRL	No
NEWBY	WABISKAW U/D-060	00/12-05-084-05W4/0	Wbsk C Sand		Produce	Shut-In		CNRL	No
NEWBY	WABISKAW T	00/06-09-084-06W4/0	Wbsk C Sand		Shut-In	Shut-In	Produce	CNRL	No
NEWBY	WABISKAW T	00/05-10-084-06W4/0	Wbsk C Sand		Shut-In	Shut-In	Produce	CNRL	No
NEWBY	WABISKAW S	00/08-12-084-06W4/0	Wbsk C Sand		Produce	Shut-In		CNRL	No
NEWBY	WABISKAW T	00/07-16-084-06W4/0	Wbsk C Sand		Shut-In	Shut-In	Produce	CNRL	No
NEWBY	WABISKAW T	00/09-17-084-06W4/0	Wbsk C Sand		Shut-In	Shut-In	Produce	CNRL	No
NEWBY	WABISKAW T	00/10-20-084-06W4/0	Wbsk C Sand		Shut-In	Shut-In	Produce	CNRL	No
NEWBY	WABISKAW T	00/10-21-084-06W4/0	Wbsk C Sand		Shut-In	Shut-In	Produce	CNRL	No
NEWBY	WABISKAW U/D-066	00/13-27-084-06W4/0	Wbsk C Sand		Shut-In	Shut-In	Produce	CNRL	No
NEWBY	WABISKAW U/D-075	00/15-17-085-06W4/0	Wbsk C Sand		Produce	Shut-In	Produce	CNRL	No
NEWBY	WABISKAW V	00/10-25-085-06W4/0	Wbsk C Sand		Produce	Shut-In		CNRL	No
NEWBY	WABISKAW V	00/10-26-085-06W4/0	Wbsk C Sand		Produce	Shut-In		CNRL	No
NEWBY	WABISKAW V	00/10-27-085-06W4/0	Wbsk C Sand		Produce	Shut-In		CNRL	No
NEWBY	WABISKAW U/D-053	AA/06-28-086-07W4/0	Wbsk C Sand		Produce	Shut-In	Produce	CANNAT RESOURCES INC.	Yes
NEWBY	WABISKAW U/D-055	AA/07-33-086-07W4/0	Wbsk C Sand		Produce	Shut-In	Produce	CANNAT RESOURCES INC.	Yes

