EnCana Corporation

Application for Special Gas Well Spacing
Lawrence Field

November 25, 2008

Energy Resources Conservation Board

ENERGY RESOURCES CONSERVATION BOARD
Decision 2008-115: EnCana Corporation, Application for Special Gas Well Spacing, Lawrence Field

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ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

ENCANA CORPORATION
APPLICATION FOR SPECIAL GAS WELL SPACING **Decision 2008-115**
LAWRENCE FIELD **Application No. 1551722**

DECISION

The Energy Resources Conservation Board has considered the findings and recommendation set out in the following examiner report, adopts the recommendation, and directs that Application No. 1551722 be approved for the Viking Formation, the Mannville Group, and the Rock Creek Member of the Fernie Group.

Dated in Calgary, Alberta, on November 24, 2008.

ENERGY RESOURCES CONSERVATION BOARD

Dan McFadyen
Chairman

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

EXAMINER REPORT RESPECTING
ENCANA CORPORATION
APPLICATION FOR SPECIAL GAS WELL SPACING **Decision 2008-115**
LAWRENCE FIELD **Application No. 1551722**

1 RECOMMENDATION

Having considered all of the evidence, the examiners recommend that Application No. 1551722 be approved for the Viking Formation, the Mannville Group, and the Rock Creek Member of the Fernie Group.

2 INTRODUCTION

2.1 Application

EnCana Corporation (EnCana) applied to the Energy Resources Conservation Board (ERCB/Board), pursuant to Section 79, Subsection 4, of the *Oil and Gas Conservation Act* (*OGCA*) and Section 5.190 of the *Oil and Gas Conservation Regulations* (*OGCR*), for the suspension of drilling spacing unit (DSU) and target area provisions and the establishment of a holding for the production of gas from the Viking Formation, Basal Colorado Sand, Mannville Group, Nikanassin Formation, and Rock Creek Member in Section 2, Township 42, Range 12, West of the 5th Meridian (Section 2). The applicant proposed that within the holding a maximum of two wells per pool per section would be produced and a producing well would be a minimum of 200 metres (m) from the boundaries of the holding.

2.2 Intervention

Ignition Energy Ltd. (Ignition) filed an objection to the application on the basis that the production data on EnCana’s 00/15-02-042-12W5 well (15-2 well) did not justify down spacing to two wells per pool per section or the relaxation of the current 300 m buffer zone. Ignition is a mineral interest owner in Section 34, Township 41, Range 12, West of the 5th Meridian (Section 34) and Section 35, Township 41, Range 12, West of the 5th Meridian (Section 35), which offset the application area to the south, and has a standing well at 02/10-34-041-12W5 (02/10-34 well).

2.3 Hearing

The Board held a public hearing in Calgary, Alberta, on August 28 and 29, 2008, before Board-appointed examiners K. G. Sharp, P.Eng. (Presiding Member), D. B. Fairgrieve, P.Geol., and T. R. Keelan, P.Eng. Those who appeared at the hearing are listed in Appendix 1.

3 BACKGROUND

Figure 1 identifies the application area and Ignition’s mineral interest area. The following wells were discussed at the hearing:

- the 15-2 well, which is located in the application area;
- the 00/06-11-042-12W5 well (6-11 well), which EnCana used extensively to support the subject application;
- the 02/10-34 well, which is Ignition's well in Section 34; and
- the 00/10-34-041-12W5 well (00/10-34 well), the only other well in Ignition's lands, which was abandoned and never produced commercial gas.

Summary information for these wells is provided in Table 1.

Table 1. Summary information on the 15-2, 6-11, 00/10-34, and 02/10-34 wells

Well	Well licensee	Current status date	Well status	Initial gas production rate (10^3 m^3/d)	Current gas production rate (10^3 m^3/d)	Cumulative gas production (10^3 m^3)
15-2	EnCana	Sep 2007	Gas flow	77.0	7.8	6585.4
6-11	EnCana	Nov 2007	Gas flow	36.5	18.4	8459.3
00/10-34	BP Canada	Feb 1983	Abandoned	N/A	N/A	N/A
02/10-34	Ignition	Feb 2007	Standing	N/A	N/A	N/A

For the 15-2 well, production from the Upper Mannville Formation, Glauconitic Sands, Ellerslie Member, and Rock Creek Member has been commingled since the commencement of production. For the 6-11 well, production from the Viking Formation, Upper Mannville Formation, Glauconitic Sands, Ellerslie Member, and Rock Creek Member has been commingled since the commencement of production. The 02/10-34 well is currently completed in the Elkton Member but has not been placed on production.

4 ISSUES

The examiners consider that approval of the requested holding would establish the equivalent of reduced gas well spacing, and they consider that the application must satisfy at least one of the requirements specified in Section 4.040(3) of the *OGCR*, which states that

> The Board shall not grant an application for an order…that would reduce the size of drilling spacing units less than the size of normal drilling spacing units unless the application shows that
>
> (a) improved recovery will be obtained,
>
> (b) additional wells are necessary to provide capacity to drain the pool at a reasonable rate that will not adversely affect recovery from the pool,
>
> (c) the drilling spacing units would be in a pool in a substantial part of which there are drilling spacing units of such reduced size, or
>
> (d) in a gas field, increased deliverability is desirable.

In addition, approval of the requested holding must not result in any unacceptable inequity.

In order to determine whether one or more of the requirements specified in Section 4.040(3) of the *OGCR* had been met and whether there would be any unacceptable inequity if reduced spacing were approved, the examiners believe the evidence presented at the hearing should be grouped under the following categories:

- the reservoir continuity of the applied-for zones,
- the reserves and drainage areas, and
- the potential to encounter incremental reserves.

5 CONSIDERATION OF THE APPLICATION

5.1 Views of EnCana

EnCana argued that its application had satisfied all or substantially all the requirements of Section 4.040(3) of the *OGCR* and, therefore, the application should be approved. It stated that

- improved recovery would be obtained,
- additional wells would be necessary to drain the pool at a reasonable rate that would not adversely affect recovery from the pool,
- the pools in the application area were small and, therefore, it would be appropriate for the Board to look within the field for examples of existing reduced spacing, and
- increased deliverability would be experienced.

EnCana did not believe that there would be any unacceptable inequity resulting from reduced spacing. EnCana stated that a second well would not drain Ignition’s lands in this tight gas play and that EnCana would not object to similar reduced spacing on Ignition’s lands if Ignition chose to apply.

5.1.1 Reservoir Continuity

In its application to establish a holding, EnCana used Notikewin, Falher, Bluesky, and Gething nomenclature to describe the Mannville deposits in the subject area. It did so in order to maintain continuity with other teams within the company and to differentiate mappable units within the Mannville. However, EnCana recognized that this nomenclature was equivalent to the Upper Mannville, Glauconitic, and Ellerslie terminology used by the ERCB for this central plains area of the province. EnCana also included the Viking Formation, Basal Colorado Sand, and Nikanassin Formation in its holding application. However, in its final argument, EnCana noted that it would seek approval of at least the Mannville Group and Rock Creek Member, as these zones were completed in the 15-2 well, and the Viking Formation, which had been identified as producing in the 6-11 well.

EnCana interpreted the Falher Member or Upper Mannville in the 15-2 and 6-11 wells to be an incised valley deposit and maintained that this was a different depositional event than that at Ignition’s 02/10-34 well. EnCana interpreted the regionally extensive and mappable coal and floodplain deposits encountered by the 02/10-34 and 11-36 wells to have been eroded in the 15-2 and 6-11 wells during a regressive cycle that resulted in the formation of an incised valley. This valley was subsequently filled during a later transgressive depositional cycle with the younger fluvial point bar sands found in the 15-2 and 6-11 wells. The fluvial point bar sands were recognized by the upward fining gamma ray log signature and by the sedimentary structures and lack of trace fossils observed in the 6-11 core. EnCana believed that erosional events such as this often acted as permeability barriers, isolating fluid flow between the incised valley deposits and the adjacent regional deposits. However, EnCana stated that the stacked point bar sands within the incised valley could be discontinuous or continuous. EnCana interpreted the Gething Formation to also be a series of laterally discontinuous stacked fluvial sands, but stated that these sands had been deposited upon a regional floodplain rather than within an incised valley. EnCana interpreted the Rock Creek sands to have been deposited in a marine environment and stated that in its experience, the Rock Creek sands were not likely to be genetically related from well to well.

EnCana submitted an oil-based core analysis from the 6-11 well that indicated that the sand matrix permeability of the Falher incised valley cored interval ranged from 0.01 millidarcy (mD) to 0.11 mD. Using the data obtained from the 6-11 oil-based core analysis, EnCana generated a porosity and permeability cross-plot that showed the Falher Member to be a tight gas reservoir requiring aggressive fracture stimulation to produce the gas in place. EnCana's data indicated that the highest porosity and permeability were located at the base of the channel, grading to lowest porosity and permeability at the top of the channel. Given this trend, EnCana stated that it could not agree with Ignition's interpretation that the 1 to 2 m interval just above the core point near the top of the channel in the 6-11 well would have uncharacteristically high in situ permeability. EnCana believed that this interval was a continuation of the upward fining incised valley deposit and, therefore, the reservoir quality would be expected to be comparable. EnCana believed that Ignition's geological interpretation was both improbable and unsubstantiated. EnCana further believed that the subject wells were within an area known as the "deep basin," below the transition zone of water to gas, where movable water did not exist. Therefore, within the deep basin, any reservoir porosity would be filled with gas molecules and pay would depend primarily on completion efficiency.

EnCana stated that based on its interpretation of the production logs from the 15-2 well taken in February 2007 and January 2008, there was a large amount of gas flowing from the upper set of Falher perforations and a minimal amount flowing from the lower set of Falher perforations. EnCana indicated that this was likely due to cross-flow occurring in the Falher reservoir. In its interpretation of the production log from the 6-11 well, EnCana stated that the gas flow in this well was very similar to that in the 15-2 well, in that a large amount of gas was flowing from the upper set of Falher perforations and a minimal amount was flowing from the lower set. EnCana added that there was potential for the fluids from the significant fracture stimulation to have entered the lower set of perforations, causing these zones to have difficulties cleaning up, thus affecting the reliability of the pressure transient analysis (PTA).

EnCana submitted that in February 2007 it had conducted a three-day pressure buildup test on the Falher Member in the 15-2 well after seven hours of flow during which it experienced a lot of liquid loading problems. This resulted in over 90 per cent of the data having no analytical value. EnCana stated that in low-permeability reservoirs, it was not unusual to have liquid loading issues and incomplete cleanup, and as a result, the permeability times thickness (kh) value determined from the PTA would be optimistic, since the pressure derivative would not show fracture linear flow due to the incomplete cleanup within the formation. EnCana further submitted that the liquid movements in the wellbore during the buildup tended to extend the wellbore storage time, since there was no stabilized wellbore volume and the liquid level was still stabilizing within the wellbore as the pressure changed. Therefore, EnCana considered that radial flow analysis on the data would result in an optimistic kh value because true pseudo-radial flow would not be seen until fracture linear flow had been observed. Consequently, EnCana did not agree with Ignition's interpretation of the 15-2 pressure buildup test.

EnCana used an October 2007 commingled initial pressure buildup test on its 6-11 well to extrapolate an initial pressure of 39 616 kilopascals absolute (kPaa) for the well prior to commercial production. This pressure was compared to the April 2007 commingled initial static gradient pressure of 39 987 kPaa for 15-2 well. The static gradient was conducted after test production only followed by a 64-day shut-in and was corrected to the midpoint of perforations in the 6-11 well for comparison purposes. EnCana stated that the pressure difference of 371 kPa was less than 1 per cent, which was within the error bar of the extrapolation given that the two wells were completed in a different combination of zones. EnCana concluded that there were no interference effects between the 15-2 and 6-11 wells. Also, EnCana indicated that during the commingled 6-11 pressure buildup test, the 15-2 well was producing about 41 10^3m^3/d during the period that the 6-11 well was shut in. When analyzing the last six hours of the commingled 6-11 buildup, EnCana calculated the pressure buildup rate to be 2.8 kPa per hour, which indicated that there was still a pressure buildup at the 6-11 well. EnCana submitted that if there were interference between the 15-2 and 6-11 wells, a slowdown in the pressure buildup would be seen and the pressure derivative would curve downwards, showing a decline in the buildup rate. EnCana stated that it could not see such a decline; therefore, it believed that no interference was occurring and that there would be no interference between wells and no pressure communication between drainage areas.

5.1.2 Reserves and Drainage Areas

EnCana estimated the original gas in place (OGIP) of the 15-2 well to be about 2900 10^6m^3, based on volumetric calculations. EnCana also hired an independent reserves auditor to analyze the production performance of the 15-2 well. The reserves auditor estimated the OGIP of the 15-2 well to be about 1200 10^6 m^3, based on volumetric calculations. EnCana estimated the ultimate recovery of the 15-2 well to be about 53 10^6m^3, based on decline analysis using a straight harmonic decline, which showed the most optimistic performance for the well. Drainage areas of 6 hectares and 15 hectares for the 15-2 well were back-calculated using the estimated ultimate recovery with EnCana's OGIP and the reserves auditor's OGIP respectively. Based on its own decline analysis, the reserves auditor estimated the remaining production life of the 15-2 well to be 41 years and the reserve life index to be 10.3 years. EnCana also indicated that when using Ignition's OGIP of 400 10^6 m^3 with the most optimistic recovery of 53 10^6 m^3, six wells per pool per section would be required in the application area to recover 75 per cent of the OGIP. Therefore, EnCana believed that more than one well in Section 2 would be required to effectively develop the requested zones.

5.1.3 Incremental Reserves

EnCana indicated that the Falher incised valley channel sands were potentially discontinuous reservoirs and that increased drilling could encounter additional sands not penetrated by its 15-2 well. EnCana also stated that incremental reserves would be obtained with downspacing because of the low drainage radius associated with the Falher.

In its discussion of the Gething Formation, EnCana stated that it believed the regional fluvial sands were laterally discontinuous and that there was no pressure continuity between the Gething sands in Section 2 and the Gething sands in Ignition's 02/10-34 well. EnCana therefore submitted that more wells drilled in Section 2 could encounter additional thin Gething gas sands beyond those that had already been penetrated by the 15-2 well.

In its geological discussion of the Rock Creek Member, EnCana interpreted a tight marine sandstone that was likely not correlative from well to well. EnCana also stated that it believed increased drilling would capture incremental gas from the Rock Creek because of its low productivity.

5.1.4 Additional Views

EnCana submitted that a reduced spacing of two wells per section had already been approved for the Notikewin Member, Falher Member, Wilrich Member, and Gething Formation zones in Section 31, Township 41, Range 12, West of the 5th Meridian. EnCana noted that the gas pool in the application area was less than one section (one DSU) in size. Thus, it felt that it would be impossible to show that reduced spacing had been approved in the same pool. Therefore, EnCana believed that it was appropriate to look at other development in the general area for corollaries.

EnCana stated that it would not be opposed to an application by Ignition to establish the same reduced spacing in Sections 34 and 35 as that proposed by EnCana for Section 2. EnCana submitted that a second well in Section 2 would result in incremental recovery that would be economic. It further added that the fact that Ignition did not view the drilling of a second well in Section 2 as satisfying its own economic criteria should not be a reason to prevent EnCana from the opportunity to produce what it considered to be economically recoverable reserves from its own land.

EnCana stated that Ignition was not contributing to either the production of the resource in the area or the provision of information that would lead to further and better development of the tight gas play. EnCana took the position that Ignition was merely challenging EnCana's interpretation of the available data rather than bringing forward substantial evidence from its 02/10-34 well and its own lands to suggest that inequitable drainage would occur.

5.2 Views of Ignition

Ignition argued that EnCana's application for reduced gas well spacing for the Viking Formation, Basal Colorado Sand, Mannville Group, Nikanassin Formation, and Rock Creek Member did not satisfy the requirements of Section 4.040(3) of the *OGCR*. Ignition was of the view that

- there was considerable doubt as to what the magnitude of the incremental recovery was, if any,
- the number of wells required to drain the pool at a reasonable rate was unknown,
- there had been no approvals for similar reduced spacing in the same pool, and
- additional wells would be uneconomic.

In its original objection, Ignition expressed concern about the relaxation of the current 300 m buffer zone to 200 m if the subject application were to be approved. However, there was no evidence or argument presented by Ignition at the hearing to address this issue.

5.2.1 Reservoir Continuity

Based on its experience of fluvial systems and current river valley analogies, Ignition interpreted the Falher Member to be a long and narrow fluvial deposit. Ignition indicated that the cored Falher interval in the 6-11 well was a thick incised valley deposit, but it interpreted that a thin, 1 to 2 m zone directly above the cored interval was possibly a regional sand rather than a continuation of the incised valley deposit. Ignition believed that this thin sand had better permeability, possibly due to larger grain size and better sorting. However, Ignition acknowledged that the log porosity of this thin sand appeared to be similar to that of the underlying sands and that there were, in fact, no actual core data to support its interpretation. Ignition believed that this 1 to 2 m sand was contributing the majority of production attributed to the Falher in the 6-11 well and posited that it could be correlated to the 15-2 well, and possibly even its own 02/10-34 well. However, Ignition acknowledged that the correlation was not strong and that it had no evidence to confirm that the main Falher channel in the 15-2 well was in pressure communication with its 02/10-34 well. Ignition stated that it was more concerned that the main Falher channel continued into Section 35 and that increased drilling would result in drainage of its gas reserves underlying Section 35. This interpretation was based on seismic data that Ignition did not submit at the hearing. Ignition believed that the fluvial deposits of the Gething and the marine sands or shoreface bars of the Bluesky and Rock Creek were also long and narrow deposits and that there was potential for reservoir continuity in these zones between the EnCana 15-2 well and its 02/10-34 well.

Ignition reviewed EnCana’s production logs for the 15-2 and 6-11 wells and stated that its interpretation showed that the majority of gas flowing out of the well was coming out of the upper set of Falher perforations. It further added that the lower Falher perforations did not show any appreciable flow on the production logs. Ignition believed that the temperature log of the 15-2 well showed a strong cooling response from the upper Falher perforations and little or no cooling response from the lower Falher perforations. Therefore, Ignition posited that the majority of the gas was flowing out of the upper Falher interval and acknowledged the possibility that the lower Falher was not contributing any gas into the 15-2 well, thus affecting the interpretation of the pressure data.

Ignition provided its evaluation of the commingled 6-11 initial buildup test conducted by EnCana in October 2007 and interpreted the extrapolated reservoir pressure to be 39 318 kPaa. Ignition stated that this was lower than the range of initial pressures for the commingled zones in EnCana’s original application and lower than the initial static gradient taken in the 15-2 well in April 2007. Ignition noted that the offset 15-2 well was producing during the 6-11 buildup test and that the lower initial pressure at the 6-11 well showed it was being influenced by that production through a thin, interconnecting, high-permeability sand in the upper Falher. Regarding the problem of comparing commingled pressures, Ignition noted that the only difference between the zones completed in the 15-2 and 6-11 wells was the Notikewin Member in the 6-11 well, which was listed as having a higher pressure than all of the other zones in the reserves report from EnCana’s independent reserves auditor. Ignition stated that when multiple layers were measured in a reservoir during a buildup test, the test would only measure the lower pressure, since the higher pressure zones would probably cross-flow into the zone at lower pressure.

Ignition provided pressure model results to support its conclusion that a thin, high-permeability sand, which was producing 80 per cent of the production from the wells, could cause the lower initial pressure interpreted from the 6-11 buildup test. Based on the model results, Ignition concluded that a thin reservoir, 568 m wide and 934 m long, extending between the 15-2 and 6-11 wells could cause the pressure to drop from an initial pressure of 40 400 kPaa to a pressure of 39 318 kPaa.

Ignition noted that the average core permeability of the upper Falher in the 6-11 well was 0.04 mD. Ignition submitted that EnCana's interpreted value of in situ permeability from the February 2007 pressure buildup test for the 15-2 well was 0.05 mD and contended that the in situ permeability should actually be much lower than the routine core permeability due to overburden effects. Therefore, Ignition concluded that the buildup test had to be measuring something other than the interval that was equivalent to the core and that the test was actually measuring a higher permeability interval corresponding to a thin, upper Falher sand that it interpreted to extend between the 15-2 and 6-11 wells (discussed above). Ignition considered this Falher interval to be 1 to 2 m thick, and by using a kh of 1.68 mD·m from the 15-2 buildup test, it calculated a value of k that ranges between 0.8 and 1.7 mD. Ignition concluded that this high-permeability interval had potential to drain across section lines, thus impacting Ignition's lands.

5.2.2 Reserves and Drainage Areas

Ignition argued that in order to demonstrate improved recovery, EnCana must have a good estimate or calculation of OGIP for the 15-2 well. It further added that it believed that EnCana's current OGIP estimates were inaccurate and thus that any reserve recovery predictions EnCana had completed were also inaccurate. Ignition had originally submitted an estimate of the OGIP for the 15-2 well to be about 400 10^6 m^3, but had subsequently reduced that estimate based on additional analysis to about 120 10^6 m^3. Based on these reduced values, Ignition estimated the drainage area of the 15-2 well to be half a section. Ignition also stated that multiple wells in the long, narrow Falher reservoir with at least some high-permeability streaks would drain the reserves underlying its lands in Section 35.

5.2.3 Incremental Reserves

Ignition's position was that there were not enough available data to conclude whether incremental reserves could be achieved through the drilling of an additional well. If EnCana were to drill another well in Section 2, Ignition believed that it would most likely accelerate production and would not add incremental reserves from the Falher Member, Gething Formation, and Rock Creek Member.

5.2.4 Additional Views

While Ignition recognized that EnCana might consider another well to be economic, it took a different view on the basis that EnCana's 6-11 and 15-2 wells did not meet Ignition's own criteria for economic wells. Ignition also maintained that EnCana had not met any of the requirements specified in Section 4.040(3) of the *OGCR* and that inequitable drainage would occur with the addition of another well.

5.3 Findings of the Examiners

The examiners consider the primary criteria in reviewing the merits of this application to be the determination of the reservoir quality, continuity of the applied-for gas pay zones, the potential to encounter incremental reserves, and what should be recognized as gas pay. Based on these factors, the examiners must determine if additional wells will improve recovery and drain the gas pay at a reasonable rate that will not adversely affect recovery.

Regarding general reservoir quality in the application area, the examiners note that both the 15-2 and 6-11 wells required significant fracture treatment to establish commercial productivity and that production rapidly declined after they were placed on production. The examiners believe that this suggests that the applied-for zones have low porosity and permeability and that production would be expected to drop rapidly as flush production within the vicinity of the hydraulic fractures shifts to production from the tighter sand matrix. The examiners note that the average core permeability of the upper Falher in the 6-11 well is 0.04 mD and that the in situ permeability would be somewhat lower. The examiners conclude from this evidence that, in general, the reservoirs in the applied-for area are generally of poor quality and would not be drained effectively by one well. Therefore, additional drilling in Section 2 will result in improved resource recovery.

Regarding reservoir continuity of the gas pay zones, the examiners do not agree with Ignition's hypothesis that a thin, continuous, high-permeability upper Falher zone connects the 15-2 and 6-11 wells and that this zone would have the potential to drain across section lines. Ignition's evidence of such a zone is based in part on its interpretation of interference effects on the 6-11 well by production from the 15-2 well and in part on its alternative interpretation of the 15-2 pressure buildup test, using the same kh from the analysis but deriving a higher value of k by using a smaller value of h. Regarding interference effects, the examiners agree with EnCana's test interpretations that indicate a 371 kPa difference between the initial pressures for the 15-2 and 6-11 wells and agree that this is within the error bar of the tests and does not indicate interference. The examiners also agree with EnCana that the different combination of zones completed in each well also makes the comparison of initial pressures difficult. Further, the examiners believe that variations in the effectiveness of zonal completions in each well influence the commingled pressure measured. The examiners do not agree with Ignition's statements that only the lowest pressure zone in a commingled well is measured in a commingled well test. Regarding Ignition's alternative interpretation of the 6-11 pressure buildup test, the examiners note that the core from the 6-11 well did not include the interval that Ignition hypothesized to be a thin, high-permeability zone. In addition, the examiners do not observe any indication from well logs that the interval is of a higher quality, and they agree with EnCana that the porosity and permeability would be expected to be comparable with the underlying cored intervals at the 6-11 well.

Regarding the potential to encounter incremental reserves, the examiners note that the parties are in agreement that the upper Falher in the 15-2 and 6-11 wells is a fluvial deposit, and the examiners agree with EnCana that these sediments are contained within an incised valley. The examiners also agree with EnCana that the incised valley is formed by erosion of previously deposited sediments and is subsequently infilled with multiple stacked fluvial point bar sands. The examiners agree with EnCana that these multiple stacked sands may be discontinuous reservoirs and that increased drilling could encounter additional fluvial point bar sands not penetrated by the 15-2 well. With respect to the secondary targets, the examiners agree with EnCana that the Gething sands are fluvial or floodplain deposits that are also discontinuous. Therefore, the examiners believe that additional drilling could encounter incremental reserves in the Gething. The examiners also agree with EnCana that the Rock Creek sands may not be correlatable between the 15-2 well and Ignition's 02/10-34 well and that increased drilling would likely capture incremental gas reserves, both because of the discontinuity of the sand and because of its low productivity.

Regarding assessment of gas pay within the application area, the examiners note that both EnCana and Ignition agreed that the postfracture production logs indicate significant flow from the upper Falher; however, some debate centred on the contribution of the lower intervals. The examiners believe that the contribution from each zone is partly dependent on the effectiveness of the fracture treatment, which can change over time and from well to well. Therefore, the examiners do not agree with Ignition's method of setting a net pay porosity cutoff based on its interpretation of the production logs. The examiners are satisfied that through the use of significant fracture treatments, there is potential for recovery from all of the perforated intervals in the 15-2 and 6-11 wells and from the zones in proximity to the perforated intervals that may contribute through cross-flow behind casing to the hydraulic fracture.

Regarding the issue of whether granting the requested holding would result in any unacceptable inequity, the examiners are of the view that Ignition has failed to establish that the applied-for holding would result in any inequitable drainage from its lands. The basis for Ignition's argument of drainage from its lands is largely based on its interpretation of a thin, high-permeability zone in the upper Falher that may extend to its lands from additional wells drilled within Section 2 under reduced spacing. The examiners do not agree with this interpretation and believe that the geology, core data, and the need for fracturing to obtain commercial production indicate that the reservoirs in the application area are discontinuous and of poor quality. The examiners also note that none of the applied-for zones have been perforated or tested in the 02/10-34 well and no well has been drilled in Section 35 and, therefore, there is no evidence that Ignition has proven reserves in its lands or a capable well. The examiners conclude that there is insufficient evidence to establish that the requested reduced spacing would result in inequitable drainage of the gas underlying Ignition's lands.

The above observations lead the examiners to conclude that additional wells are required to effectively drain the reserves underlying Section 2. It is the examiners' view that additional wells will allow for drainage of the section at a reasonable rate and will not adversely impact recovery. Therefore, the application satisfies the criteria in Sections 4.040(3) (a) and (b) of the *OGCR*.

The examiners note that Ignition's original objection argued that the holding should have a 300 m buffer zone rather than the 200 m buffer zone requested by EnCana, and that this was not addressed by Ignition at the hearing. However, since Ignition failed to show it has proven reserves or capable wells on its lands, the examiners believe that concern about the buffer zone size is not relevant to this decision. Therefore, the ERCB's standard buffer zone of 200 m will be applied to the holding, in accordance with *Bulletin 2007-27*.

The examiners note that the ERCB uses Upper Mannville, Glauconitic, and Ellerslie terminology to describe the Mannville deposits in this area of the province, rather than the age-equivalent northwest plains nomenclature of Notikewin, Falher, Bluesky, and Gething, as was used by the participants at the hearing. The examiners further note that the Basal Colorado Sand and the Nikanassin Formation, although applied for within the holding, were not interpreted to have been deposited in the 15-2 well, and that no evidence was presented at the hearing to suggest that incremental reserves would be recovered from these zones. Therefore, the examiners recommend that the requested reduced spacing should apply to the Mannville Group and the Rock Creek Member of the Fernie Group, as well as to the Viking Formation, since it has been identified as producing in the 6-11 well.

6 CONCLUSION

Based on the above, the examiners believe that EnCana's application meets two of the criteria upon which the Board may grant reduced spacing. Specifically, reduced spacing would result in improved gas recovery and additional wells are needed to drain the pool at a reasonable rate. Approval of the application would not result in an unacceptable inequity to Ignition, as it has not demonstrated that it has proven reserves or a capable well on its lands or that reduced spacing in the application area could result in drainage across section lines. The examiners also note that Ignition does have the opportunity of submitting an application to produce more than one well in Sections 34 and 35. The examiners therefore recommend that the application be approved for the Viking Formation, the Mannville Group, and the Rock Creek Member of the Fernie Group.

Dated in Calgary, Alberta, on November 21, 2008.

ENERGY RESOURCES CONSERVATION BOARD

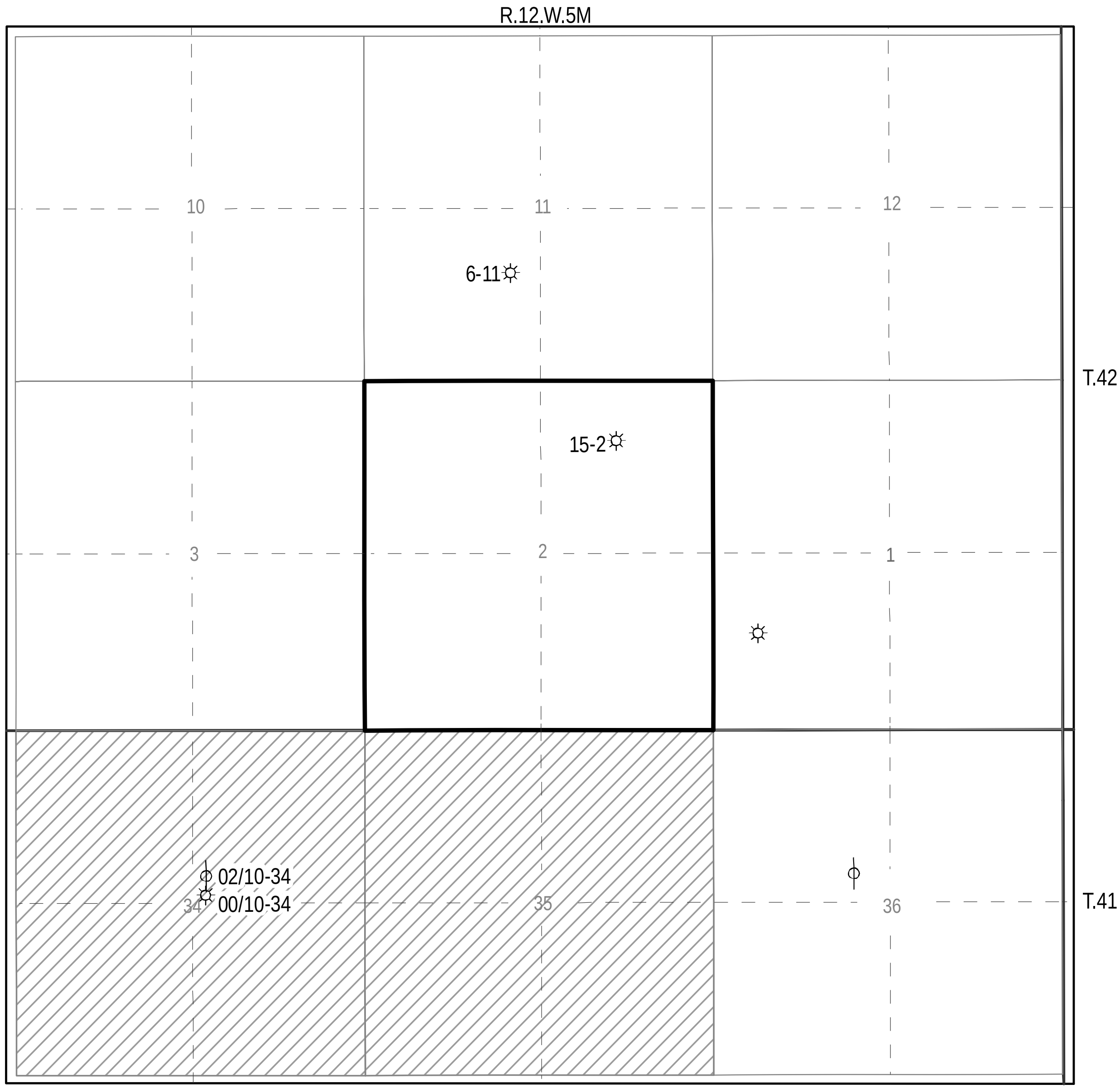
K. G. Sharp, P.Eng.
Presiding Member

D. B. Fairgrieve, P.Geol.
Examiner

T. R. Keelan, P.Eng.
Examiner

APPENDIX 1 HEARING PARTICIPANTS

Principals and Representatives (Abbreviations used in report)	Witnesses
EnCana Corporation (EnCana) S. Munro S. Carter	T. Brown, P.Eng. D. Hoffman, P.Eng. H. Du, P.Eng. D. Potocki, P.Geol. S. Addison D. Block, P.Geol. J. MacFarlane, T.T.
Ignition Energy Ltd. (Ignition) H. Clark G. Fitch	H. Clark
Energy Resources Conservation Board staff T. Grimoldby, Board Counsel A. Lung K. Fisher K. Bieber, P.Geol. T. Rempfer, P.Eng.	



Legend

Gas well

Suspended well

Application area

Mineral interests - Ignition Energy Ltd.

0 0.5 1 1.5 km
1:30 000

Figure 1. Lawrence field