Manitoba Developed Ultimate Recovery (DUR) Review

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FOREWORD

This annual report was compiled by Hakeem Ibrahim, M.Sc., for the Director of the Petroleum Branch in accordance with section 11(4) of The Oil & Gas Act. Information pertaining to the history of field or pool designations may be obtained by contacting the Petroleum Branch.

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1 SUMMARY

The developed reserves for all oil pools with wells classified as “Capable of Oil Production” (COOP) in the Province of Manitoba have been evaluated using both decline curve analysis (DCA) and analytical methods. The DCA analyses were done by carrying out a regression on the performance of wells in each oil pool such that actual decline curve was adequately defined for all the wells and/or oil pools currently capable of oil production. Analogy based analytical evaluations were carried out, based on provincial abandoned vertical well data, and neighbouring Saskatchewan abandoned horizontal well data (as there is limited abandoned horizontal well count in Manitoba) for determining abandonment parameters in the DCA. Proved (1P) and Proved + Probable (2P) estimates were derived for each oil pool in line with industry standards.

Using this method the 1P and 2P developed/expected ultimate recovery EUR/DUR obtained for the Province are 49.7 * $10^6 m^3$ and 52.6 * $10^6 m^3$ of oil, respectively. This represents 1P and 2P developed reserves of 6.62 * $10^6 m^3$ and 9.5 * $10^6 m^3$ respectively at year end 2009. The corresponding reserves life indices are 4.4 years and 6.3 years in the proven and expectation cases respectively. The table below presents a summary of the results.

Year	Annual Production (10^3 m^3)	Cumulative Production (10^6 m^3)	**Proved (1P)**					**Proved + Probable (2P)**		
			Dev. Reserve (10^6 m^3)	Developed Utimate Recovery (10^6 m^3)	Annual Reserve Additions (10^6 m^3)	Reserve Life Index (Years)	Reserve Additions to Production Ratio	Dev. Reserve (10^6 m^3)	Developed Utimate Recovery (10^6 m^3)	Reserve Life Index (Years)
2009	1520	43.06	6.6	49.7	9.20	4.4	6.05	9.5	52.60	6.3

2 INTRODUCTION

Commercial oil production/pumping commenced in Manitoba in the Daly (now Daly/Sinclair) field in February 1951. The province commenced water flooding two years after, in April 1953, while CO_2 injection commenced in August 2008. The productive areas of the Province are located along the north-eastern flank of the Williston basin. Rocks of the Palaeozoic, Mesozoic and Cenozoic ages form a basin-ward thickening wedge of sedimentary strata to a total depth of 2300 m in the southwest corner of the Province.

The Manitoba oil reservoirs are predominantly under saturated with very low initial solution GOR. Oil production is currently limited to the sandstones of the Jurassic Amaranth Formation, the carbonates of the Mississippian Lodgepole and Mission Canyon formations, and the sandstones of the Mississippian Bakken formation[1]. There are currently 14 (13 plus "Other") designated oil fields and 135 oil pools in the province.

A total of 6,808 wells had been drilled in the province, with 3065 wells still capable of oil production (COOP) by year end 2009. Total production of $1.52 * 10^6 m^3$ was recorded in the year, and hence a cumulative oil production of $43.06 * 10^6 m^3$ to year end 2009 (Fig. 1). A massive boost in development activities (drilling, unitization and enhanced oil recovery - water flooding and CO_2) between 2004 and 2009 resulted in a ~46% increase in well count with a corresponding increase in average daily oil production of ~59%. The detailed results of this review are presented in Tables 1-3 and appendices 1-6.

3 METHODOLOGY

Decline curve analysis has been carried out for all oil pools classified as "Capable of Oil Production" (COOP) in Manitoba. Given the number of drainage points/wells (>7000) involved and the associated resource constraints, the evaluations were done at field and pool code, and unit levels for all COOP vertical (and deviated) and horizontal wells respectively using GEOSCOUT[2] to appropriately describe the observed historical performance of each field/pool/unit codes and thereafter, to predict future performance under the prevailing conditions. Attention has been focused on extrapolating periods of stable performance in order to obtain realistic estimates. In cases where there is a change in drainage point status through activities such as bean (choke) changes, stimulation, zone changes etc, new DUR estimates have been generated in line with new observations. Where there is considerable uncertainty in the drainage point performance, the proved (1P)[3] estimate has been chosen in line with the most conservative trend observed in the performance data. The 2P estimate reflects the expected value using all available data, and has been taken as the expectation value in all cases.

3.1 Data Accuracy & Uncertainty Management

The results/reserves in this report are as accurate as the GEOSCOUT which formed input to the evaluations. Field unitization is gaining more popularity amongst operators in the province. There were observed inconsistencies between well, Pool and field. These are usually results of errors in production allocation and reconciliation. Another source of error in this work was in field pool and unit coding. The coding was somewhat confusing in the way they were done. This was especially so in cases where there have code changes over time. To address this situation, the DCA was at pool/unit levels where possible. It is believed that this approach significantly reduced the error margin in the work.

In the cases of fluctuation in well(s) performance(s), proper DCA requires a full understanding of the reasons behind fluctuation in performance to enable a more accurate reserves assignment. The limited well history data in system did not help in having a good insight into the factors behind well behavior, thus creating uncertainty in the assigned reserves. The same is true of abandonment parameters, and other areas where there was sparse data availability.

3.2 Analysis Methods

The following analysis methods have been employed in arriving at the EUR/DUR estimates.

- Oil rate vs. cumulative oil production has been used where the drainage point has a defined oil rate decline trend. Most Manitoba field reservoirs/drainage points have clearly shown exponential decline trends in their historical performance and this has been used in most cases.
- The abandonment oil rates were based on analogy. This involved the analytical evaluations of abandonment rates for abandoned vertical wells in Manitoba, and abandoned horizontal wells in neighbouring Saskatchewan (as there is scanty abandoned horizontal well count in Manitoba).
- Where there is yet no discernible decline associated with the field/pool/unit production (e.g. new wells and wells producing at plateau), the DUR/reserve estimates have been based on operators' advised estimates based on their in-house and independent evaluations, where available. Validity checks carried out for a few cases confirmed consistency between the operators' estimates and estimates from this review.
- Where operators' DUR/reserve estimates are not available, the DUR estimates has been based on production volumes for a few years, usually between one and three

years for proved (depending on performance and history); and between two and four years for expectation (depending on performance and history), at an observed average production (pump) rate.

- For closed-in wells with no immediate future scope of further production, the cumulative production (Np) has been taken as the proved and expectation DUR values, hence no reserves are assigned.
- Water cut versus cumulative oil production has not been applied in cases where there is a clear water-cut trend, because GEOSCOUT does not allow the flexibility of extrapolating on water cut.

3.3 Associated Gas Reserves

Manitoba oil is largely under-saturated, with little solution gas in association with the oil. A significant percentage of the gas produced in the province is currently being flared or vented. Further to this, there is a significant level of uncertainty associated with gas measurement/metering in the province. On account of these, it was believed that gas reserves evaluation may not be reliable at this time, and hence not considered in this review.

3.4 Undeveloped Reserves

There have recently been new project applications (including unitization, new drilling and EOR techniques). Some of these projects have been executed in 2010, while others are still pending approval and/or execution. The oil reserves associated with these projects are also not considered in this study, as only events occurring before end of 2009 have been covered.

4 Daly Sinclair Field

The Daly Sinclair field commenced oil production in July 1951 (Fig. 2), while water flooding commenced in December 2009. A total of 2226 wells have been completed and produced in this field, 1652 of which were classified as COOP wells and 150 as water injectors. The field's cumulative production at year end 2009 was 9.74 $*10^6m^3$ of oil. The estimated 1P and 2P developed reserves 3.54 10^6m^3 and 4.78 10^6m^3 respectively.

4.1 Lodgepole A (01_59A)

The Lodgepole A commenced oil production in July 1951 (Fig. 3). A total of 201 wells have been completed and produced in the pool. The COOP well count in the year was 199 (192 vertical and 7 horizontal), with a total cumulative oil production of 3.89 $*10^6m^3$ at year end 2009. The estimated 1P and 2P developed reserves are 0.51 10^6m^3 and 1.0 10^6m^3 respectively. This represents an estimated 1P and 2P developed reserves contribution of 480 10^3m^3 and 970 10^3m^3 respectively from vertical wells; and 30 10^3m^3 respectively from horizontal wells.

4.1.1 Lodgepole A - 01_59A (Non-Unitized)

This group of wells commenced oil production in 1952 (Figures 4 - 9). There is a total 69 (67 vertical and 2 horizontal) non-unitized COOP wells completed (or produced) in the pool, with a total cumulative oil production of 600 $*10^3m^3$ at year end 2009. The estimated 1P and 2P developed reserves are 80 $* 10^3m^3$ and 170 $* 10^3m^3$ respectively. This represents exponential declines of 11.44% and 29.76% per year for the vertical and horizontal wells respectively in the 1P case; and 5.29 and 28.09 percent for the vertical and horizontal wells respectively in the 2P case.

4.1.2 Lodgepole A - 01_59A (Unit 1)

The unit no. 1 commenced oil production in May 1952 (Figures 10 -12). There were 30 vertical COOP wells completed (or produced) in the unit, with a cumulative oil production of 1.20 $*10^6m^3$ at year end 2009. The estimated 1P and 2P developed reserves are 70 10^3m^3 and 180 10^3m^3 using exponential declines of 10.59 and 3.94 percent per year respectively.

4.1.3 Lodgepole A - 01_59A (Unit 3)

The unit no. 3 wells commenced oil production in 1951 (Figures 13 - 18). There is a total of 51 (46 vertical and 5 horizontal) COOP wells completed (or produced) in the unit, with a total cumulative oil production of 1.86 $*10^6m^3$ at year end 2009. The estimated 1P and 2P developed reserves are 320 $* 10^3m^3$ and 560 $* 10^3m^3$. These represent exponential declines of 5.3% and 11.42% per year for the vertical and horizontal wells respectively in the 1P case; and 2.92 and 10.42 percent for the vertical and horizontal wells respectively in the 2P case.

4.1.4 Lodgepole A - 01_59A (Unit 4)

The unit no. 4 wells commenced oil production in November 1983 (Figures 19 - 21). There are 49 vertical COOP wells completed (or produced) in this unit, with a cumulative oil production of 1.51 $*10^6m^3$ at year end 2009. The estimated 1P and 2P developed reserves are 40 $* 10^3m^3$ and 90 $* 10^3m^3$ using exponential declines of 9.92% and 4.62% per year respectively.

4.2 Lodgepole B (01_59B)

The Lodgepole B commenced oil production in July 1951 (Figures 22 - 27). The COOP well count in 2009 was 33 (26 vertical and 7 horizontal), with a total cumulative oil production of 188.52 $*10^3m^3$ at year end 2009. The estimated 1P and 2P developed reserves are 17.80 $* 10^3m^3$ and 25.20 $* 10^3m^3$ respectively. These represent exponential declines of 14.12% and 57.16% per year for the vertical and horizontal wells respectively in the 1P cases; and 14.12% and 47.71% for the vertical and horizontal wells respectively in the 2P case.

In the vertical case DCA, there had been a sudden drop in the production rate (from 65 bopd to 46 bopd) at the end of history. As the sudden drop in production has not been established with consistency, this thus formed the basis of sensitivity for the 1P and 2P cases, using the same decline trend (14.12% per year). In the 1P case (Fig. 23), it was assumed that the sudden decline was indeed sustained; hence 46 bopd was used as the forecast start rate. The 2P case DCA (Fig. 24) assumed that the sudden decline was not sustained, thus 65 bopd was used as the forecast start rate.

4.3 Lodgepole C (01_59C)

The Lodgepole C was brought on production in August 1954 (Figures 28 - 30). The COOP well count in 2009 was 4 vertical wells, with a cumulative oil production of 94.1 $*10^3m^3$ at year end 2009. The pool's yearly average daily oil production declined from 70bbl/day in 1999 to <10bbl/day a year later, without any corresponding increase in water cut and/or drop in well count. As a result of the relatively low daily rates, the abandonment oil rate was set at 1bbl/day (avg. 2009 daily production was 3.06bbl/day) in the DCA. This resulted in estimated 1P and 2P developed reserves of 0.91 10^3m^3 and 1.25 10^3m^3 respectively. These represent exponential declines of 12.1% and 8.66% percent per year respectively for the 1P and 2P cases.

4.4 Lodgepole D (01_59D)

The Lodgepole D was brought on production in March 1965 (Figures 31 & 34). The COOP well count in the year was 89 vertical wells, with a cumulative oil production of 2.84 $*10^6m^3$ at year end 2009. The estimated 1P and 2P developed reserves are 56.74 $* 10^3m^3$ and 66.79 10^3m^3 respectively.

4.4.1 Lodgepole D - 01_59D (Non-Unitized)

There are a total of 187 wells drilled and completed (6 as injectors) in this unit, 86 of which (vertical) were counted as COOP. Total cumulative oil production was 462.29 $*10^3m^3$ at year end 2009. The estimated 1P and 2P developed reserves are 55.69 $* 10^3m^3$ and 65.28 $* 10^3m^3$ respectively (Figures 31 - 33). This represents exponential declines of 15.40 and 12.35 percent per year for the 1P and 2P cases respectively.

4.4.2 Lodgepole D - 01_59D (Unit 5)

There are a total of 7 wells drilled and completed (2 as injectors) in this unit, 3 of which (vertical) were counted as COOP. Total cumulative oil production was 42.62 $*10^3m^3$ at year end 2009. (Figures 34 -36). The estimated 1P and 2P developed reserves are 1.05 $* 10^3m^3$ and 1.51 10^3m^3 using exponential declines of 13.85% and 8.28% per year respectively.

4.5 Lodgepole E (01_59E)

The Lodgepole E commenced oil production in July 1951 (Figures 37 & 40). There are a total of 53 wells drilled and completed (2 as injectors) in this unit, 25 of which (11 vertical and 14 horizontal) were counted as COOP. Total cumulative oil production was 354.93 $*10^3m^3$ at year end 2009. The estimated 1P and 2P developed reserves are 34.80 * 10^3m^3 and 54.96 * 10^3m^3 respectively (Fig. 37 – 42). This represents an estimated 1P and 2P developed reserves contribution of 6.42 10^3m^3 and 16.95 10^3m^3 respectively from vertical wells; and 28.38 * 10^3m^3 and 39.01 *10^3m^3 respectively from horizontal wells. These represent exponential declines of 15.92 and 25.87 percent per year for the vertical and horizontal wells respectively in the 1P case; and 6.82 and 18.7 percent for the vertical and horizontal wells respectively in 2P case.

4.6 Lodgepole F (01_59F)

The Lodgepole F commenced oil production in July 1951 (Figures 43 & 46). The COOP well count in the year was 8 vertical wells, with a total cumulative oil production of 42.77 *10^3m^3 at year end 2009. The estimated 1P and 2P developed reserves are 32.06 10^3m^3 and 57.81 10^3m^3 respectively.

4.6.1 Lodgepole F - 01_59F (Non-unitized)

There are 6 vertical non-unitized COOP wells completed (or produced) in this pool, with cumulative oil production of 16.01 *10^3m^3 at year end 2009. The estimated 1P and 2P developed reserves are 3.18 * 10^3m^3 and 5.79 * 10^3m^3 respectively (Figures 42 - 44). These represent exponential declines of 22.31% and 12.32% per year for the 1P and 2P cases respectively.

4.6.2 Lodgepole F - 01_59F (Unit 1)

The unit no. 1 wells were brought on production in January 1956 (Figures 45 -48). There are 2 vertical COOP wells completed (or produced) in the unit, with a cumulative oil production of 26.75 *10^3m^3 at year end 2009. The estimated 1P and 2P developed reserves are 1.91 * 10^3m^3 and 3.40 10^3m^3 using exponential declines of 14.38 and 9.01 percent per year respectively.

4.7 Lodgepole I (01_59I)

The Lodgepole I was brought on production in June 2002 (Fig. 49). COOP well count in 2009 was 3 vertical/deviated wells, with a cumulative oil production of 2.17 * 10^3m^3 at year end 2009. Estimated 1P and 2P developed reserves are 0.54 * 10^3m^3 and 0.88 10^3m^3 (Figures 50 - 51) using exponential declines of 18.97 and 13.46 percent per year respectively.

4.8 Lodgepole S (01_59S)

The Daly Sinclair Lodgepole S was brought on production in June 2009 (Fig. 52). The COOP well count in 2009 was 2 vertical/deviated wells, with a cumulative oil production of 0.29 * 10^3m^3 at year end 2009. There is no discernible decline for a realistic decline curve analysis, due to the limited production history for the wells. The attempted DCA (Fig. 53) resulted in a rather high decline rate of 43.17% per year and reserve of 3.15 * 10^3m^3. Consequently, 1P and 2P reserves were assigned as 2 (4.67 * 10^3m^3) and 3 (7.01 * 10^3m^3) years of current production respectively. Hence 1P and 2P developed ultimate recovery (DUR) of 6.47 * 10^3m^3 and 8.81 * 10^3m^3 respectively.

4.9 Lodgepole T (01_59T)

The Lodgepole T commenced production in July 2001 (Fig. 54). COOP well count in 2009 was 2 vertical/deviated wells, with a cumulative oil production of 1.63 * 10^3m^3 at year end 2009. Estimated 1P and 2P developed reserves are 0.4 * 10^3m^3 and 0.57 10^3m^3 (Figures 55 - 56) using exponential declines of 11.24% and 17.18% per year respectively.

4.10 Lodgepole V (01_59V)

The Lodgepole V commenced production in September 2008 (Fig. 57). COOP well count in 2009 was 5 vertical/deviated wells, with a cumulative oil production of 1.42 * 10^3m^3 at year end 2009. There is limited production data, and there are no Operator assessed reserves for this pool. DCA (Fig. 58-59) resulted in 1P and 2P reserves of 2.04 * 10^3m^3 and 3.55 * 10^3m^3, representing exponential declines of 32.22% and 21.32% per year respectively.

4.11 Lodgepole Y (01_59Y)

The Lodgepole Y commenced production in July 2006 (Fig. 60). COOP well count in 2009 was 3 vertical/deviated wells, with a cumulative oil production of 0.94 * 10^3m^3 at year end 2009. Estimated 1P and 2P developed reserves are 0.22 * 10^3m^3 and 0.79 10^3m^3 (Figures 61 - 62) using exponential declines of 23.47% and 6.82% per year respectively.

4.12 Lodgepole AA (01_59AA)

The Lodgepole AA commenced oil production in October 1993. COOP well count in 2009 was 16 (15 vertical and 1 horizontal), with a total cumulative oil production of 11.69 *10^3m^3 at year end 2009. Estimated 1P and 2P developed reserves are 8.08 10^3m^3 and 10.56 10^3m^3 respectively. These represent exponential declines of 41.14% and 14.42% per year for the vertical and horizontal wells respectively in the 1P cases; and 41.14% and 11.41% for the vertical and horizontal wells respectively in the 2P case (Figures 63 - 68).

In the vertical well case DCA, the production rate and producing well count fluctuated between ~200 bopd and <40 bopd; and 15 and 12 wells respectively in 2009 (Fig. 63). These fluctuations formed the basis of sensitivity for the 1P and 2P cases, using the same decline trend (41.14% per year). In the 1P case (Fig. 64), it was assumed that the decline rate was indeed sustained; hence the end 2009 rate of ~65 bopd was used as the forecast start rate. The 2P case DCA (Fig. 66) assumed that the rate decline was not sustained; hence a higher oil rate of 102 bopd was used as the forecast start rate.

4.13 Lodgepole BB (01_59BB)

The Lodgepole BB pool commenced oil production in August 2007 (Fig. 69). COOP well count in the year was 6 vertical/deviated wells, with a cumulative oil production of 3.52 * 10^3m^3 at year end 2009. Estimated 1P and 2P developed reserves 1.16 * 10^3m^3 and 1.65 * 10^3m^3 respectively (Figures 70 & 71). This represents an exponential decline of 34.18% and 33.63% per year for the 1P and 2P cases respectively.

4.14 Lodgepole CC (01_59CC)

The Daly Sinclair Lodgepole CC commenced oil production in June 2006 (Fig. 72). The COOP well count in the year was 5 vertical/deviated wells, with a cumulative oil production of 2.89 * 10^3m^3 at year end 2009. The estimated 1P and 2P developed reserves 3.46 * 10^3m^3 and 4.12 * 10^3m^3 respectively (Figures 73 & 74). This represents an exponential decline of 26.34 and 24.5 percent per year for the 1P and 2P cases respectively. Hence 1P and 2P developed ultimate recovery (DUR) of 6.36 10^3m^3 and 7.02 * 10^3m^3 respectively.

4.15 Lodgepole DD (01_59DD)

The Lodgepole DD pool commenced oil production in 1986. COOP well count in 2009 was 15 (14 vertical and 1 horizontal), with a total cumulative oil production of 18.18 *10^3m^3 at year end 2009.

The producing vertical well count increased from 2 (end 2006) to 14 (end 2009) corresponding to an increase in production of 3.34bbl/day to >100bbl/day (Fig. 75). But, production declined sharply by end 2009, with producing well dropping to 8. The same exponential decline of 15.73% per year was applied for the 1P and 2P cases. For the 1P case, the decline in rate to ~52 was assumed to be sustained, and thus used for the DCA (Fig. 76). In the 2P case, it was assumed that this last decline was not sustained, and that some of the non producing COOP wells were brought back on production. Hence, an improved rate of 80bbl/day was for used as the forecast start rate (Fig. 77). The estimated 1P and 2P developed reserves are 17.42 * 10^3m^3 and 25.86 * 10^3m^3 respectively.

The sole horizontal well completed on this pool has at best, recorded erratic performance since coming on stream in January 1994. Its end year 2009 cumulative production was a mere 0.19 * 10^3m^3 (Fig. 78). The well quit production in July 2009; hence no oil reserve was assigned to this well, as there are no clear short term plans to bring it back on production.

4.16 Lodgepole DD (01_59EE)

Only one vertical/deviated well has been completed on this pool. The well, which commenced production in November 2006, quit in June 2007 after a cumulative production of 0.72 * 10^3m^3 (Fig. 79). Hence, no oil reserve was assigned to this well, as there are no clear short term plans to bring it back on production.

4.17 Bakken A – (01_60A)

The Bakken A commenced oil production in March 1993 (Figures 80 & 83). The COOP well count in the year was 36 (29 vertical and 7 horizontal), with a total cumulative oil production of 243.30 *10^3m^3 at year end 2009. The estimated 1P and 2P developed reserves are 70.56 * 10^3m^3 and 120.30 * 10^3m^3 respectively.

4.17.1 Bakken A - 01_60A (Non-unitized)

There are 12 vertical and 7 horizontal non-unitized COOP wells completed (or produced) in this pool, with cumulative oil production of 59.40 *10^3m^3 at year end 2009. Estimated 1P and 2P developed reserves are 40.47 * 10^3m^3 and 61.19 * 10^3m^3 respectively (Figures 81- 82 & 84 - 85). This represents exponential declines of 13.67% and 23.28% per year for the vertical and horizontal wells respectively in the 1P; and 9.63% and 15.19% per year for the vertical and horizontal wells respectively in the 2P cases.

4.17.2 Bakken A - 01_60A (Unit 1)

The Bakken unit no. 1 wells were brought on production in January 1986 (Fig. 86). There are 8 vertical COOP wells completed (or produced) in the unit, with a cumulative oil production of 71.53 *10^3m^3 at year end 2009. Estimated 1P and 2P developed reserves are 5.29 * 10^3m^3 and 24.74 10^3m^3 using exponential declines of 21.72% and 5.04% per year respectively (Figures 87 – 88).

4.17.3 Bakken A - 01_60A (Unit 2)

The Bakken unit no. 2 wells were brought on production in March 1993 (Fig. 89). There are 9 vertical COOP wells completed (or produced) in the unit, with a cumulative oil production of 112.36 *10^3m^3 at year end 2009. Estimated 1P and 2P developed reserves are 24.81 * 10^3m^3 and 34.37 * 10^3m^3 using exponential declines of 11.09% and 8.29% per year respectively (Figures 90 – 91). Hence 1P and 2P developed ultimate recovery (DUR) of 137.17 * 10^3m^3 and 146.74 * 10^3m^3 respectively.

4.18 Bakken B (01_60B)

The Bakken B commenced oil production in June 19895. The COOP well count in 2009 was 9 vertical, while 1 horizontal was brought in January 2010. The year end 2009 cumulative oil production was 4.79 $*10^3m^3$.

The vertical well case 1P and 2P developed reserve estimates are 1.17 $* 10^3m^3$ and 1.72 10^3m^3 using exponential declines of 19.64 and 13.75 percent per year respectively (Figures 92 – 94). Hence 1P and 2P developed ultimate recovery (DUR) of 5.96 $* 10^3m^3$ and 6.52 $* 10^3m^3$ respectively.

The sole horizontal well completed on this pool was brought on stream in January 2010(Fig. 95); hence no reserves are assigned.

4.19 Bakken G (01_60G)

The Bakken G pool commenced oil production in October 2006 (Fig. 96). The sole well completed on this pool had recorded a cumulative oil production of 0.47 $* 10^3m^3$ at year end 2009. The well had been erratic (producing only a few months at a time, before quitting again), and characterized by excessive water cut over its life. The erratic well performance has resulted in insufficient production data for DCA. Additionally, the Operator does not carry any reserves for the well. The estimated 1P and 2P developed reserve of 0.24 $* 10^3m^3$ was assigned on the assumption that the well is at worse, capable of producing a yearly average of 5bbl/day for 10 years (as advised by Operator).

4.20 Bakken I – (01_60I)

The Bakken I first produced in July 1992. The COOP well count in the year was 18 (16 vertical and 2 horizontal), with a total cumulative oil production of 51.19 $*10^3m^3$ at year end 2009. Estimated 1P and 2P developed reserves are 12.84 $* 10^3m^3$ and 25.61 $* 10^3m^3$ respectively.

4.20.1 Bakken I - 01_60I (Non-unitized)

There are 7 vertical and 2 horizontal non-unitized COOP wells completed (or produced) in this pool, with cumulative oil production of 22.82 $*10^3m^3$ at year end 2009.

The vertical well case 1P and 2P developed reserve estimates are 12.84 $* 10^3m^3$ and 25.61 $* 10^3m^3$ respectively (Figures 97 - 99). This represents exponential declines of 19.95% and 7.98% per year in the 1P and 2P cases respectively.

The two horizontal wells completed on this pool/unit was brought on stream in June 2006 with very erratic performances, without any production in the entire 2009 (production re-started early 2010); hence there is insufficient production history for DCA (Fig. 100). At a cumulative production of 1.0 $* 10^3m^3$, the 1P and 2P reserves assignment was based on 1 and 2 years production at current rate, resulting in 1.66 $* 10^3m^3$ and 3.32 $* 10^3m^3$ respectively.

4.20.2 Bakken I - 01_60I (Unit 1)

The unit no. 1 wells were brought on production in July 1992 (Fig. 101). There are 9 vertical/deviated COOP wells completed (or produced) in the unit, with a cumulative oil production of 28.37 $*10^3m^3$ at year end 2009. Estimated 1P and 2P developed reserves are 4.98 $* 10^3m^3$ and 6.21 $* 10^3m^3$ using exponential declines of 11.23% and 9.14% percent per year respectively (Figures 102 - 103).

4.21 Bakken J – (01_60J)

The Bakken J first produced in October 1993. The COOP well count in 2009 was 2 (1 vertical and 1 horizontal), with a total cumulative oil production of 35.72 *10^3m^3 at year end 2009. The vertical well quit production in September 2009 (Fig. 104); hence no reserves are assigned to it in this review.

The Horizontal well first produced in November 2008. Its average water cut has been >86% while oil rate has halved from ~50bbl/day to ~22bbl/day between February 2009 and now. Its estimated 1P = 2P developed reserves is 3.52 * 10^3m^3 (Figures 105 - 106) representing exponential declines of 28.98% per year.

4.22 Bakken N – (01_60N)

The Bakken N commenced oil production in November 1993 (Fig. 107). The COOP well count in the year was 15 vertical/deviated wells, with a cumulative production of 36.78 * 10^3m^3 at year end 2009. Estimated 1P and 2P developed reserves are 2.89 * 10^3m^3 and 15.9 * 10^3m^3 respectively (Figures 108 & 109). This represents exponential declines of 41.45% and 8.90% per year for the 1P and 2P cases respectively.

4.23 Bakken P – (01_60P)

The Bakken P commenced oil production in October 1994 (Fig. 110). COOP well count in the year was 2 vertical/deviated wells, with a cumulative oil production of 2.82 * 10^3m^3 at year end 2009. Estimated 1P and 2P developed reserves are 0.55 * 10^3m^3 and 1.08 * 10^3m^3 respectively (Figures 111 & 112), representing exponential declines of 19.88% and 10.42% per year for the 1P and 2P cases respectively.

4.24 Bakken Q – (01_60Q)

The Bakken Q commenced oil production in December 1994 (Fig. 113). COOP well count in the year was 6 vertical/deviated wells, with a cumulative oil production of 6.09 * 10^3m^3 at year end 2009. Estimated 1P and 2P developed reserves are 1.12 * 10^3m^3 and 2.02 * 10^3m^3 respectively (Figures 114 & 115), representing exponential declines of 21.57% and 11.33% per year for the 1P and 2P cases respectively.

4.25 Bakken R (01_60R)

Only one vertical/deviated well has been completed on this pool. The well which commenced production in August 2006, quit in December 2008 after a cumulative production of 0.43 * 10^3m^3 (Fig. 116). Hence, no oil reserve was assigned to this well, as there are no clear short term plans to bring it back on production.

4.26 Bakken V – (01_60V)

The Bakken V pool commenced oil production in November 1995 (Fig. 117). The sole COOP well had recorded a cumulative oil production of 2.99 * 10^3m^3 at year end 2009. Estimated 1P and 2P developed reserves are 0.54 * 10^3m^3 and 0.85 * 10^3m^3 respectively (Figures 118 & 119), representing exponential declines of 10.07% and 6.47% per year for the 1P and 2P cases respectively.

4.27 Bakken Z – (01_60Z)

The Bakken Z commenced oil production in September 1999 (Fig. 120). The COOP well count in the year was 17 vertical/deviated wells, with a cumulative oil production of 32.94 * 10^3m^3 at year end 2009. Estimated 1P and 2P developed reserves are 9.40 * 10^3m^3 and 11.07 *

10^3m^3 respectively (Figures 121 & 122). This represents exponential declines of 15.22% and 13.94% per year for the 1P and 2P cases respectively.

4.28 Bakken BB – (01_60BB)

The Bakken BB commenced oil production in June 2000 (Fig. 123). COOP well count in the year was 5 (4 vertical/deviated and 1 horizontal) wells, with a cumulative oil production of 9.53 * 10^3m^3 at year end 2009. 1P and 2P developed reserve estimates are 2.26 * 10^3m^3 and 3.47 * 10^3m^3 respectively.

The vertical wells contribution to the estimated 1P and 2P developed reserves are 0.63 * 10^3m^3 and 1.05 * 10^3m^3 respectively (Figures 124 & 125). This represents exponential declines of 29.18% and 18.17% per year for the 1P and 2P cases respectively.

The horizontal well commenced production in March 2009 (Fig. 126). Due to the sparse production data available for the well, there was no flexibility in choosing decline trends for the 1P and 2P cases respectively. An exponential decline of 27.94% per year was applied for the 1P DCA (Fig. 127). The 2P developed reserve was assigned based on 3 years production at current rate. These resulted in 1P and 2P developed reserve estimates of 1.62 * 10^3m^3 and 2.42 * 10^3m^3 respectively.

4.29 Bakken FF – (01_60FF)

The Bakken FF commenced oil production in August 2008 (Fig. 128) from the sole horizontal well. Due to the sparse production data available for the well, there was no flexibility in choosing separate decline trends for the 1P and 2P cases respectively. An exponential decline of 40.79% per year was applied for the 1P DCA case (Fig. 129). The 2P developed reserve was assigned based on 3 years production at current rate. These yielded 1P and 2P developed reserve estimates of 3.57 * 10^3m^3 and 7.72 * 10^3m^3 respectively.

4.30 Bakken Three Forks A – (01_62A)

The Bakken Three Forks A first produced in October 1987. COOP well count in the year was 16 (9 vertical and 7 horizontal), with a total cumulative oil production of 92.73 *10^3m^3 at year end 2009. The pool production was boosted by the drilling of horizontal wells causing production to jump from ~30bbl/day (in August 2009) to the present >200bbl/day level. The 1P and 2P developed reserve estimates are 28.05 * 10^3m^3 and 43.46 * 10^3m^3 respectively.

4.30.1 Bakken Three Forks A – 01_62A (Non-unitized)

There are 7 horizontal non-unitized COOP wells completed (or produced) in this pool, with cumulative oil production of 3.41 *10^3m^3 at year end 2009 (Fig. 130).

Due to the sparse production data available for the pool DCA, the 1P and 2P reserves assignment was based on 2 and 3 years production at current rate, resulting in 1P and 2P developed reserve estimates of 20.40 * 10^3m^3 and 30.60 * 10^3m^3 respectively.

4.30.2 Bakken Three Forks A – 01_62A (Unit 1)

The unit no. 1 wells were brought on production in October 1987 (Fig. 131). There are 4 vertical/deviated COOP wells completed (or produced) in the unit, with a cumulative oil production of 33.68 *10^3m^3 at year end 2009. Estimated 1P and 2P developed reserves are 2.78 * 10^3m^3 and 3.91 * 10^3m^3 using exponential declines of 14.15% and 10.57% per year respectively (Figures 132 - 133).

4.30.3 Bakken Three Forks A – 01_62A (Unit 2)

The unit no. 2 wells were brought on production in March 1989 (Fig. 134). There are 5 vertical/deviated COOP wells completed (or produced) in the unit, with a cumulative oil production of 55.64 *10^3m^3 at year end 2009. The estimated 1P and 2P developed reserves are 4.87 * 10^3m^3 and 8.94 * 10^3m^3 using exponential declines of 18.53% and 9.52% percent per year respectively (Figures 135 - 136).

4.31 Bakken Three Forks B – (01_62B)

The Bakken Three Forks B first produced in May 1994. COOP well count in the year was 1069 (914 vertical and 158 horizontal), with a total cumulative oil production of 2578.41 *10^3m^3 at year end 2009. The pool`s production benefited significantly from the deployment of horizontal wells which caused production to spike from a yearly average of ~380bbl/day in 2004 to ~3300bbl/day the following year, and >12800bbl/day in 2009. The estimated pool 1P and 2P developed reserves are 2718.40 * 10^3m^3 and 3302.74 * 10^3m^3 respectively.

4.31.1 Bakken Three Forks B – 01_62B (Non-unitized)

There are 532 vertical/deviated and 144 horizontal non-unitized COOP wells completed (or produced) in this pool, with cumulative oil production of 1314.54 *10^3m^3 at year end 2009.

The vertical wells with a cumulative production of 1028 * 10^3m^3 (Fig. 137), contribute estimated 1P and 2P developed reserves of 473.51 * 10^3m^3 and 579.67 * 10^3m^3 respectively (Figures 138 & 139), representing exponential declines of 28.44% and 24.07% per year for the 1P and 2P cases respectively.

The horizontal wells commenced production in April 2007 (Fig. 140) with cumulative production of 286.44 * 10^3m^3. Due to sparse data availability, the 1P has been equated to the 2P, hence 1P =2P developed reserves are 1431.48 * 10^3m^3 (21.20% per year decline rate) based on the single discernible decline to data (Fig. 141).

4.31.2 Bakken Three Forks B – 01_62B (Unit 1)

There are 138 vertical/deviated and 1 horizontal non-unitized COOP wells completed (or produced) in this pool, with cumulative oil production of 534.20 *10^3m^3 at year end 2009.

The vertical wells with a cumulative production of 515.93 * 10^3m^3 (Fig. 142), contribute estimated 1P and 2P developed reserves of 479.45 * 10^3m^3 and 873.58 * 10^3m^3 respectively (Figures 143 & 144), representing exponential declines of 34.26% and 15.29% per year for the 1P and 2P cases respectively.

The horizontal wells commenced production in July 2005 (Fig. 145) with cumulative production of 18.27 * 10^3m^3. Estimated 1P and 2P developed reserves are 7.31 * 10^3m^3 and 12.45 * 10^3m^3 respectively (Figures 146 & 147), representing exponential declines of 50.16% and 30.38% per year for the 1P and 2P cases respectively.

4.31.3 Bakken Three Forks B – 01_62B (Unit 2)

There are 144 vertical/deviated and 2 horizontal COOP wells completed (or produced) in this unit, with a cumulative oil production of 325.91 *10^3m^3 at year end 2009 (Fig. 148). The estimated 1P and 2P developed reserves for the vertical wells are 164.85 * 10^3m^3 and 201.18 * 10^3m^3 using exponential declines of 35.01% and 29.40% per year respectively (Figures 149 - 150).

The horizontal wells commenced production in July 2008 (Fig. 151), and have had cumulative production of 4.03 * 10^3m^3. Estimated 1P and 2P developed reserves are 2.34 * 10^3m^3 and

2.72 * 10^3m^3 respectively (Figures 152 & 153), representing exponential declines of 57.75% and 52.27% per year for the 1P and 2P cases respectively.

4.31.4 Bakken Three Forks B – 01_62B (Unit 3)

The unit no. 3 wells were brought on production in November 2004 (Fig. 154). There are 96 vertical/deviated COOP wells completed (or produced) in the unit, with a cumulative oil production of 367.07 *10^3m^3 at year end 2009. Estimated 1P and 2P developed reserves are 129.86 * 10^3m^3 and 171.30 * 10^3m^3 using exponential declines of 31.10% and 18.35% per year respectively (Figures 155 - 156).

4.31.5 Bakken Three Forks B – 01_62B (Unit 4)

There were 4 vertical/deviated and 11 horizontal COOP wells completed (or produced) in this unit, with a cumulative oil production of 6.02 *10^3m^3 at year end 2009 (Fig. 157). The 1P and 2P developed reserve estimates for the vertical wells are 1.30 * 10^3m^3 and 2.06 * 10^3m^3 using exponential declines of 34.45% and 25.44% per year respectively (Figures 158 - 159).

The horizontal wells commenced production in November 2005 (Fig. 160) with cumulative production of 26.66 * 10^3m^3. The DCA estimates of 1P and 2P developed reserves are 6.41 * 10^3m^3 and 6.89 * 10^3m^3 respectively (Figures 161 & 162), representing exponential declines of 65.16% and 61.37% per year for the 1P and 2P cases respectively.

But, given the unrealistically high decline rates (reserves life index of ~1 year) in the DCA estimates, the more realistic operator assessed reserves (June 2010) of 178,000 bbl (28.30 * 10^3m^3), corresponding to a reserves life of ~4 years, was carried as 1P = 2P developed reserves.

4.32 Bakken Three Forks N – (01_60N)

The Bakken Three Forks N commenced oil production in January 2006 (Fig. 163), and had recorded a cumulative production of 0.36 * 10^3m^3 at year end 2009. Due sparsity of data, there was no flexibility in picking declines for the 1P and 2P cases. Hence, 1P = 2P developed reserve estimate was based on a decline rate of 23.68% per year, resulting in 0.15 * 10^3m^3 (Fig. 164). This result is consistent with the operator's evaluation.

4.33 Bakken Three Forks R – 01_62R

There is 1 horizontal COOP well completed (or produced) on this pool, with a cumulative oil production of 0.41 *10^3m^3 at year end 2009. It commenced production in December 2009 (Fig. 165), and there was sparse data availability for DCA. The DCA estimates of 1P = 2P developed reserves was 0.76 * 10^3m^3 (Fig. 166), representing exponential declines of 79.64% per year.

But, given this unrealistically high decline rate (reserves life index of ~0.5 year) in the DCA estimate, the 1P and 2P developed reserves of 1.30 * 10^3m^3 and 2.60 * 10^3m^3 were based on 1 and 2 years production respectively, at current rates.

4.34 Bakken Three Forks S – 01_62S

There are 4 vertical/deviated and 1 horizontal COOP wells completed (or produced) in this unit, with a cumulative oil production of 86.48 *10^3m^3 at year end 2009 (Fig. 167).

The vertical wells recorded first production in January 2003 and cumulative production of 13.60 *10^3m^3 at year end 2009. The 1P and 2P developed reserve estimates for the vertical wells are 4.85 * 10^3m^3 and 7.20 * 10^3m^3 using exponential declines of 19.15% and 12.94% per year respectively (Figures 168 - 169).

The horizontal wells commenced production in August 2009 (Fig. 170), and have cumulative production of 0.15 * 10^3m^3. Due to sparse data availability for DCA, the Operator advised reserves (at June 2010) of 5,000 bbl (0.79 * 10^3m^3), was carried as 1P = 2P developed reserves.

4.35 Bakken Three Forks T – (01_62T)

The Bakken Three Forks T pool (1 well) commenced oil production in April 2003 (Fig. 171), and had recorded a cumulative production of 1.74 * 10^3m^3 at year end 2009. The well production had declined from the 2008 calendar day average of 4.3bbl/day to 3.96bbl/day in 2009 and 2010 year-to-date average of 2.95bbl/day. Production declined from 2.97bbl/day in Feb. 2010 to 1.30bbl/day in March, before jumping to 3.96bbl/day. Following from these fluctuation in rates, the 1P and 2P DCA were based on initial forecast rates of 3.57bbl/day and 3.82bbl/day respectively. This yielded 1P and 2P developed reserve estimates of 1.09 * 10^3m^3 and 1.53 * 10^3m^3 respectively (Figures 171 - 173) from decline rates of 11.07% and 8.45% per year respectively.

4.36 Bakken Three Forks U – 01_62U

There is one horizontal COOP well completed (or produced) in this unit, with a cumulative oil production of 7.10 *10^3m^3 at year end 2009 (Fig. 174). The well commenced production in February 2009. Due to sparse data availability, the attempted DCA (Fig. 175) with resulted in a reserve of 7.28 *10^3m^3 (at a decline rate of 44.42% per year). The decline rate being too high and consequently the reserve being too low for a well with such healthy performance, the Operator advised reserves (at June 2010) of 66,000 bbl (10.49 * 10^3m^3), was carried as 1P = 2P developed reserves respectively.

4.37 Bakken Three Forks V – (01_62V)

The Bakken Three Forks V pool (1 well) commenced oil production in February 2003 (Fig. 176), and had recorded a cumulative production of 0.38 * 10^3m^3 at year end 2009. The well production has declined from the initial ~25bbl/day to the present levels of <3bbl/day, suggesting that the well is approaching its end of life. Following from this, the 1P and 2P DCA were based on initial forecast rates of ~1.5bbl/day. This resulted in 1P and 2P developed reserve estimates of 0.08 * 10^3m^3 and 0.11 * 10^3m^3 respectively (Figures 177 - 178) from decline rates of 43.94% and 34.58% percent per year respectively.

4.38 Bakken Three Forks W – 01_62W

There is one horizontal COOP well completed (or produced) in this unit, with a cumulative oil production of 7.10 *10^3m^3 at year end 2009 (Fig. 179). The well commenced production in June 2009. The DCA (Fig. 180) with available data resulted in 1P = 2P developed reserves of 0.78 *10^3m^3.

4.39 Three Forks A – (01_65A)

The Three Forks A pool (1 well) commenced oil production in March 2006 (Fig. 181), and had recorded a cumulative production of 4.13 * 10^3m^3 at year end 2009. The well's production has been fairly stable. 1P and 2P developed reserve estimates was 1.62 * 10^3m^3 and 2.38 * 10^3m^3 respectively (Figures 182 - 183) from decline rates of 22.07% and 15.40% percent per year respectively.

5 Tilston Field

The Tilston field commenced oil production (Fig. 184) and water flooding commenced in August 1952 and May 1959 respectively. A total of 56 wells have been completed in the field, 23 of which were counted as COOP wells in 2009. The field's cumulative production at year end 2009 was 425.85 *10^3m^3. The 1P and 2P developed reserve estimates are 3.90 * 10^3m^3 and 8.48 * 10^3m^3 respectively.

5.1 Mission Canyon 1A (02_44A)

There are 6 vertical/deviated and 4 horizontal COOP wells completed (or produced) in this pool, with a cumulative oil production of 59.45 *10^3m^3 at year end 2009. The vertical wells recorded first production in August 1957 and cumulative production of 33.76 *10^3m^3 at year end 2009 (Fig. 185). The 1P and 2P developed reserve estimates for the vertical wells are 0.86 * 10^3m^3 and 1.72 * 10^3m^3 using exponential declines of 22.01% and 17.03% percent per year respectively (Figures 186 - 187).

The horizontal wells commenced production in October 1994 (Fig. 188) with cumulative production of 25.69 * 10^3m^3. The wells quit production in January 2010, hence no reserves are assigned.

5.2 Mission Canyon 1C (02_44C)

There are 3 vertical/deviated and 6 horizontal COOP wells completed (or produced) in this unit, with a cumulative oil production of 212.22 *10^3m^3 at year end 2009. The vertical wells recorded first production in November 1983 and cumulative production of 33.85 *10^3m^3 at year end 2009 (Fig. 189). Two of the COOP wells had quit production by March 2009, with the remaining well producing at <2bbl/day all through 2009 (1.01bbl/day in September). Due to these low rates and given its producing status, the abandonment oil rate was adjusted to 0.6 bbl to enable reserves assignment. The 1P and 2P developed reserve estimates for the vertical wells are 0.1 * 10^3m^3 and 0.02 * 10^3m^3 using exponential declines of 16.12% and 14.60% per year respectively (Figures 190 - 191).

The horizontal wells commenced production in November 1993 (Fig. 192) with cumulative production of 178.37 * 10^3m^3. The 1P and 2P developed reserve estimates for the vertical wells are 1.80 * 10^3m^3 and 4.79 * 10^3m^3 using exponential declines of 36.0% and 20.37% per year respectively (Figures 193 - 194).

5.3 Mission Canyon 1D (02_44D)

There are 1 vertical/deviated and 3 horizontal COOP wells completed (or produced) in this unit, and a cumulative oil production of 62.33 *10^3m^3 at year end 2009. The sole vertical well recorded first production in July 1994 and cumulative production of 9.11 *10^3m^3 at year end 2009 (Fig. 195). The well's production has been fairly stable at <2bbl/day over the past one and half years. Due to these low rates and given its producing status, the abandonment oil rate was adjustment to 0.8 bbl to enable reserves assignment. The 1P and 2P developed reserve estimates for the vertical wells are 0.16 * 10^3m^3 and 0.42 * 10^3m^3 using exponential declines of 30.02% and 15.14% per year respectively (Figures 196 - 197).

The horizontal wells commenced production in November 1994 (Fig. 198), and have a cumulative production of 53.22 * 10^3m^3. The wells' production has been fairly stable between 10bbl/day and 15bbl/day over the past eight years. The 1P and 2P developed reserve estimates are 0.99 * 10^3m^3 and 1.35 * 10^3m^3 using exponential declines of 27.82% and 16.58% per year respectively (Figures 199 - 200).

6 Waskada Field

The Waskada field commenced oil production and water flooding in September 1952 (Fig. 201) and August 1966 respectively. A total of 1096 wells have been drilled in the field, 507 of which were classified as COOP wells in 2009, while 171 were injector wells. The field has benefited significantly from horizontal well technology and water flooding. Its cumulative production at year end 2009 was 4.46 $*10^6m^3$ of oil, with estimated 1P and 2P developed reserves 1.05 $* 10^6m^3$ and 1.54 $* 10^6m^3$ respectively.

6.1 Lower Amaranth A – (03_29A)

The Lower Amaranth A COOP well count in the year was 259 (Fig. 202), with a total cumulative production of 582.19 $*10^3m^3$ at year end 2009. The pool's 1P and 2P developed reserve estimates are 195.83 10^3m^3 and 319.68 10^3m^3 respectively.

6.1.1 Lower Amaranth A - 03_29A (Non-Unitized)

The non-unitized well (COOP) in the year were 119 (95 vertical and 24 horizontal), with a total cumulative oil production of 0.56 $*10^6m^3$ at year end 2009. The vertical wells recorded first production in November 1982, and cumulative production of 529.39 $*10^3m^3$ at year end 2009 (Fig. 203). 1P and 2P developed reserve estimates are 109.34 $* 10^3m^3$ and 233.19 $* 10^3m^3$ using exponential declines of 16.47% and 7.88% per year respectively (Figures 204 - 205).

The horizontal wells commenced production in February 2007 (Fig. 206), and have a cumulative production of 31.72 $* 10^3m^3$. The wells recorded a sharp decline in the 3rd quarter of 2009 after reaching its peak, and production has been declining steadily in 2010. These factors have meant that there is no discernible decline for DCA evaluation. Hence, 1P = 2P, resulting in developed reserves of 86.49 $* 10^3m^3$ at an exponential declines of 42.75% per year respectively (Fig. 207).

6.1.2 Lower Amaranth A - 03_29A (Unit 1)

The Unit no. 1 COOP well count in the year was 13 (12 vertical and 1 horizontal), with a total cumulative oil production of 281.19 $*10^3m^3$ at year end 2009. The vertical wells recorded first production in November 1981, and cumulative production of 273.02 $*10^3m^3$ at year end 2009 (Fig. 208). The estimated 1P and 2P developed reserves are 5.22 $* 10^3m^3$ and 24.44 $* 10^3m^3$ using exponential declines of 25.35% and 6.46% per year respectively (Figures 209 - 210).

The horizontal well commenced production in October 1994 (Fig. 211), and has cumulative production of 8.17 $* 10^3m^3$. The well has recently experienced a sharp decline from its peak, and production has been declining steadily in 2010. The 1P and 2P developed reserve estimates are 1.73 $* 10^3m^3$ and 4.09 $* 10^3m^3$ at exponential declines of 35.67% and 15.09% per year respectively (Figures 211 - 212).

6.1.3 Lower Amaranth A - 03_29A (Unit 2)

The Unit no. 2 COOP well count in the year was 4 (3 vertical and 1 horizontal), with a total cumulative oil production of 50.28 $*10^3m^3$ at year end 2009. The vertical wells recorded first production in June 1982, and have a cumulative production of 49.51 $*10^3m^3$ at year end 2009 (Fig. 214). The 1P and 2P developed reserve estimates are 1.83 $* 10^3m^3$ and 5.21 $* 10^3m^3$, using exponential declines of 19.6% and 7.88% per year respectively (Figures 215 - 216).

The horizontal well commenced production in March 2010 (Fig. 217), and has cumulative production of 0.76 $* 10^3m^3$. The well is yet to hit potential and no decline has yet been observed for a DCA. 1P and 2P developed reserve estimates of 1.83 * 10^3m^3 and 5.21 * 10^3m^3 are based on operator supplied EUR of 51.34 * 10^3m^3 and 54.71 * 10^3m^3 respectively.

6.1.4 Lower Amaranth A - 03_29A (Unit 3)

The unit no. 3 COOP well count in the year was 13 (11 vertical and 2 horizontal), with a total cumulative oil production of 85.43 *10^3m^3 at year end 2009. The vertical wells recorded first production in November 1982, and have a cumulative production of 85.12 *10^3m^3 at year end 2009 (Fig. 218). The wells have experienced fairly stable production at an average of ~25bbl/day in recent years. 1P and 2P developed reserve estimates are 8.02 * 10^3m^3 and 12.32 * 10^3m^3, at exponential declines of 18.19% and 12.66% per year respectively (Figures 219 - 220).

The horizontal wells commenced production in December 2009 (Fig. 221), and have a cumulative production of 0.31 * 10^3m^3. The wells produced to a peak of >200bbl/day, and declined sharply to ~75bbl/day, hence there is no realistic decline for DCA. 1P and 2P developed reserve estimates of 17.41 * 10^3m^3 and 26.11 * 10^3m^3 were assigned based on two 2 and 3 years production respectively, at current rate.

6.1.5 Lower Amaranth A - 03_29A (Unit 4)

The unit no. 4 COOP well count in the year was 14 vertical wells, with a total cumulative oil production of 153.99 *10^3m^3 at year end 2009. The wells recorded first production in March 1982 (Fig. 222). The 1P and 2P developed reserve estimates are 14.94 * 10^3m^3 and 18.07 * 10^3m^3, at exponential declines of 13.33% and 8.17% per year respectively (Figures 223 - 224).

6.1.6 Lower Amaranth A - 03_29A (Unit 5)

The unit no. 5 COOP well count in the year was 15 (12 vertical and 3 horizontal), with a total cumulative oil production of 79.61 *10^3m^3 at year end 2009. The vertical wells recorded first production in August 1983, and cumulative production of 77.84 *10^3m^3 at year end 2009 (Fig. 225). Recent performance of the wells has been fairly stable, with satisfactory water cut profile. The 1P and 2P developed reserve estimates are 5.33 * 10^3m^3 and 14.78 * 10^3m^3, at exponential declines of 21.6% and 9.42% per year respectively (Figures 226 - 227).

The horizontal wells commenced production in November 2009 (Fig. 228), and have cumulative production of 1.77 * 10^3m^3. The wells produced to a peak of ~250bbl/day, and declined sharply to ~170bbl/day within a six month interval, hence there is no discernible decline for DCA. The 1P and 2P developed reserve estimates of 32.06 * 10^3m^3 and 44.14 * 10^3m^3 are based on Operator supplied reserves of ~71,000 bbl per well.

6.1.7 Lower Amaranth A - 03_29A (Unit 6)

The unit no. 6 COOP well count in the year was 12 vertical, with a total cumulative oil production of 178.92 *10^3m^3 at year end 2009. The wells recorded first production in November 1982 (Fig. 229). The 1P and 2P developed reserve estimates are 9.97 * 10^3m^3 and 15.50 * 10^3m^3 at exponential declines of 11.2% and 6.67% per year respectively (Figures 230 - 231).

6.1.8 Lower Amaranth A - 03_29A (Unit 7)

The unit no. 7 has one well, which recorded first production in March 1983 and a total cumulative production of 15.68 *103m 3 at year end 2009 (Fig. 232). The 1P and 2P developed reserve estimates are 2.28 * 10^3m^3 and 3.34 * 10^3m^3 at exponential declines of 14.55% and 10.04% per year respectively (Figures 233 - 234).

6.1.9 Lower Amaranth A - 03_29A (Unit 8)

The unit no. 8 COOP well count in the year was 9 vertical, with a total cumulative oil production of 132.43 $*10^3m^3$ at year end 2009. The wells recorded first production in March 1982 (Fig. 235). Recent performance of the wells has been fairly stable with satisfactory water cut profile. The 1P and 2P developed reserve estimates are 5.94 $* 10^3m^3$ and 11.07 $* 10^3m^3$, at exponential declines of 8.17 and 13.33 percent per year respectively (Figures 237 - 238).

6.1.10 Lower Amaranth A - 03_29A (Unit 13)

The unit no. 13 COOP well count in the year was 7 (vertical), with a total cumulative oil production of 39.75 $*10^3m^3$ at year end 2009. The wells recorded first production in February 1994 (Fig. 239). The wells have had declining performance of recent, though with satisfactory water cut profile. The wells have produced with significant downtime. Hence, higher initial rates were applied for the forecast start rates (~19bbl/day for 1P and ~37bbl/day for 2P). The resulting 1P and 2P developed reserve estimates are 2.09 $* 10^3m^3$ and 6.06 $* 10^3m^3$, at exponential declines of 37.84 and 13.9 percent per year respectively (Figures 240 - 241).

6.1.11 Lower Amaranth A - 03_29A (Unit 14)

The unit no. 14 COOP well count in the year was 1 vertical well, with a total cumulative oil production of 5.52 $*10^3m^3$ at year end 2009. The wells have had declining performance of recent, though with satisfactory water cut profile. The 1P and 2P developed reserve estimates are 0.03 $* 10^3m^3$ and 0.06 $* 10^3m^3$, at exponential declines of 36.36 and 16.42 percent per year respectively (Figures 242 - 243).

6.1.12 Lower Amaranth A - 03_29A (Unit 15)

The unit no. 15 wells recorded first production in July 1984 (Fig. 244). All COOP wells quit production in 2008, except one, which quit in February 2010, after a total cumulative oil production of 35.92 $*10^3m^3$. Hence zero reserves have been assigned to these wells.

6.1.13 Lower Amaranth A - 03_29A (Unit 16)

The unit no. 16 COOP well count in the year was 9 vertical wells, with a total cumulative oil production of 383.52 $*10^3m^3$ at year end 2009. The wells recorded first production in July 1984 (Fig. 245). These wells have enjoyed healthy performance, with satisfactory water cut profile. The 1P and 2P developed reserve estimates are 61.03 $* 10^3m^3$ and 89.86 $* 10^3m^3$, at exponential declines of 13.26% and 9.16% per year respectively (Figures 246 - 247).

6.1.14 Lower Amaranth A - 03_29A (Unit 17)

The Unit no. 17 COOP well count in the year was 16 vertical, with a total cumulative oil production of 188.92 $*10^3m^3$ at year end 2009. The wells recorded first production in January 1986 (Fig. 248). These wells have enjoyed very healthy performance, with satisfactory water cut profile. The 1P and 2P developed reserve estimates are 47.28 $* 10^3m^3$ and 76.05 $* 10^3m^3$, at exponential declines of 12.64% and 7.01% per year respectively (Figures 249 - 250).

6.1.15 Lower Amaranth A - 03_29A (Unit 18)

The unit no. 18 COOP well count in the year was 18 (13 vertical and 5 horizontal), with a total cumulative oil production of 85.71 $*10^3m^3$ at year end 2009. The vertical wells recorded first production in March 1990, and cumulative production of 85.12 $*10^3m^3$ at year end 2009 (Fig. 251). The wells have enjoyed fairly stable production at averaging ~60bbl/day for many years, with satisfactory water cut profile. The 1P and 2P developed reserve estimates are 27.61 $* 10^3m^3$ and 41.47 $* 10^3m^3$, at exponential declines of 9.66 and 6.48 percent per year respectively (Figures 252 - 253).

The horizontal wells commenced production in October 2007 (Fig. 254), and have cumulative production of 4.16 * 10^3m^3. The unit produced at a stable rate of ~20bbl/day, from one well. Production peaked at ~500bbl/day upon deployment of the additional 4 horizontal wells in October 2009, before declining to ~400bbl/day, by April 2010. As there is no realistic decline for DCA, the 1P = 2P developed reserve estimates is 42.85 * 10^3m^3 at 45.09% decline per year (Fig. 255).

6.1.16 Lower Amaranth A - 03_29A (Unit 19)

The unit no. 19 COOP well count in the year was 34 (22 vertical and 12 horizontal), with a total cumulative oil production of 97.68 *10^3m^3 at year end 2009. The vertical wells recorded first production in December 2001, and have cumulative production of 66.75 *10^3m^3 at year end 2009 (Fig. 256). The wells have enjoyed fairly stable production for many years, with satisfactory water cut profile. The 1P and 2P developed reserve estimates are 25.89 * 10^3m^3 and 62.38 * 10^3m^3, at exponential declines of 19.86% and 8.39% per year respectively (Figures 257 - 258).

The horizontal wells commenced production in July 2008 (Fig. 259), and have cumulative production of 30.93 * 10^3m^3. Production peaked at ~1500bbl/day upon deployment of more horizontal wells in February 2009. Decline set in after peak production, before a second peak by February 2010 upon the deployment of the last set of horizontal wells to date. As there is no realistic decline for DCA, attempted DCA (45.09% decline per year) resulted in EUR of 83.72 * 10^3m^3 using (Fig. 260). The Operator advised EUR of 70,000 bbl per well was carried instead, thus yielding the 1P = 2P developed reserve estimates of 102.62 * 10^3m^3.

6.2 Lower Amaranth I – (03_29I)

The Lower Amaranth I pool COOP well count in the year was 151 (98 vertical and 53 horizontal), with a total cumulative oil production of 376.20 *10^3m^3 at year end 2009. The pool's estimated 1P and 2P developed reserves are 351.45 * 10^3m^3 and 477.41 * 10^3m^3 respectively.

6.2.1 Lower Amaranth I - 03_29I (Non-Unitized)

The non-unitized COOP wells in the year was 137 (84 vertical and 53 horizontal), with a total cumulative oil production of 325.35 *10^6m^3 at year end 2009. The vertical wells recorded first production in January 1997, and had cumulative production of 195.07 *10^3m^3 at year end 2009 (Fig. 261). In late 2004, there was further development activity increasing well count from 35 to ~80. This boosted production from ~320bbl/day to a peak of ~1200bbl/day before declining steadily to ~300bbl/day by 2010. The estimated 1P and 2P developed reserves are 79.74 * 10^3m^3 and 114.49 * 10^3m^3 at exponential declines of 14.24% and 12.86% per year respectively (Figures 262 - 263).

The horizontal wells commenced production in November 1997 (Fig. 264) with cumulative production of 130.28 * 10^3m^3. Production increased progressively and peaked at ~4200bbl/day with the progressive deployment of more wells between 2007 and 2009, and declined to ~3000bbl/day by end 2009. 1P and 2P developed reserve estimates are 259.74 * 10^3m^3 and 338.85 * 10^3m^3 using exponential declines of 59.17% and 47.34% per year respectively (Figures 265 - 266).

6.2.2 Lower Amaranth I - 03_29I (Unit 1)

The unit no. 1 COOP well count in the year was 14 vertical, with a total cumulative oil production of 50.85 *10^3m^3 at year end 2009. The wells recorded first production in January 2001 (Fig. 267). These wells have enjoyed very healthy performance, with satisfactory water cut profile. 1P and 2P developed reserve estimates are 11.97 * 10^3m^3 and 24.07 * 10^3m^3, at exponential declines of 15.49% and 12.47% per year respectively (Figures 268 - 269).

6.3 Lower Amaranth O - 03_29O

The lower Amaranth O pool COOP well count in the year was 3 (2 vertical and 1 horizontal), with a total cumulative oil production of 1.57 *10^3m^3 at year end 2009. The vertical wells recorded first production in February 2005, and cumulative production of 1.02 *10^3m^3 at year end 2009 (Fig. 270). The wells' performance is characterized by downtime. Production peaked with a spike of ~90bbl/day in May 2009. Production has since declined to <4bbl/day, though with stable water cut at an average of 50%. 1P and 2P developed reserve estimates are 0.18 * 10^3m^3 and 0.26 * 10^3m^3, at exponential declines of 55.66% and 41.47% per year respectively (Figures 271 -272).

The horizontal wells commenced production in December 2009 at ~110bbl/day, and declined sharply to ~5bbl/day by March 2010 (Fig. 273). Cumulative production was 4.16 * 10^3m^3 year end 2009. As there is no realistic decline for DCA, 1P and 2P developed reserve of 7.27 * 10^3m^3 and 8.66 * 10^3m^3 were based on Operator's estimates.

6.4 Mission Canyon 3b A – (03_42A)

The Mission Canyon 3b A COOP well count in the year was 2 vertical wells, with a total cumulative oil production of 64.49 *10^3m^3 at year end 2009. The estimated pool 1P and 2P developed reserves are 5.98 * 10^3m^3 and 13.21 * 10^3m^3 respectively.

6.4.1 Mission Canyon 3b A - 03_42A (Non-Unitized)

The non-unitized COOP well count in the year was 1 vertical well, with a cumulative oil production of 41.98 *10^3m^3 at year end 2009. The well recorded first production in June 1968 (Fig. 274). It has produced satisfactorily, with average oil rate of 8bbl/day in the past six years. 1P and 2P developed reserve estimates are 5.43 * 10^3m^3 and 11.70 * 10^3m^3, using exponential declines of 5.45% and 2.43% per year respectively (Figures 275 - 276).

6.4.2 Mission Canyon 3b A - 03_42A (Unit 1)

The unit no. 1 COOP well count in the year was 1 vertical well, with cumulative oil production of 22.50 *10^3m^3 at year end 2009 (Fig. 277). The well has experienced significant instability in its performance in recent years, due to high water cut. The abandonment oil rate for DCA was set as 0.2 bbl given that the well is currently producing at very low oil rate (<3bbl/day). 1P and 2P developed reserve estimates are 0.55 * 10^3m^3 and 1.52 * 10^3m^3, at exponential declines of 18.95% and 10.76% per year respectively (Figures 278 - 279).

6.5 Mission Canyon 3b B – (03_42B)

The Mission Canyon 3b B COOP well count in the year was 4 vertical and 2 horizontal wells, with a total cumulative oil production of 49.59 *10^3m^3 at year end 2009. The estimated pool 1P and 2P developed reserves are 2.14 * 10^3m^3 and 6.51 * 10^3m^3 respectively.

6.5.1 Mission Canyon 3b B - 03_42B (Non-Unitized)

The non-unitized COOP well count in the year was 5 (3 vertical and 2 horizontal), with a total cumulative oil production of 37.02 *10^3m^3 at year end 2009. The vertical wells recorded first production in September 1981, and had cumulative production of 18.18 *10^3m^3 at year end 2009 (Fig. 280). The wells increased in production from ~7bbl/day to ~16bbl/day in 2008, before declining to 0bbl/day in 2009. Production had return to ~14bbl/day by end 2009. Estimated 1P and 2P developed reserves are 1.15 * 10^3m^3 and 4.92 * 10^3m^3 at exponential declines of 14.56% and 11.78% per year respectively (Figures 281 - 282).

The horizontal wells commenced production in July 1994 (Fig. 283). Only two COOP wells are still producing (the 3rd last produced in 2006), one of which is producing at end of its life (with high water cut). Currently, production is ~5bbl/day. End 2009 cumulative production was 18.83 * 10^3m^3. With its recent low oil rate, 1P = 2P developed reserve estimates is 0.42 * 10^3m^3, at exponential declines of 10.38% per year respectively (Figures 284).

6.5.2 Mission Canyon 3b B - 03_42B (Unit 9)

The unit no. 9 COOP well count in the year was 1 vertical well. The well recorded first production in December 2002, and has end year 2009 cumulative production of 12.57 *10^3m^3 (Fig. 285). The well has produced at an average oil rate of ~4bbl/day in the past six years. 1P and 2P developed reserve estimates are 0.57 * 10^3m^3 and 1.17 * 10^3m^3, at exponential declines of 37.44% and 10.03% per year respectively (Figures 286 - 287).

6.6 Mission Canyon 3a A (03_43A)

This pool had a COOP well count of 3 (2 vertical and 1 horizontal) as unit no. 12, with a total cumulative oil production of 28.472 *10^3m^3 at year end 2009. The vertical wells recorded first production in November 1981, and had cumulative production of 21.69 *10^3m^3 at year end 2009 (Fig. 288). The wells have produced satisfactorily at average production of ~10bbl/day between 1998 and 2006, after which production has been declining to date. Recent production has been ~4bbl/day. The estimated 1P and 2P developed reserves are 0.34 * 10^3m^3 and 0.58 * 10^3m^3 using exponential declines of 33.09% and 13.74% per year respectively (Figures 289 - 290).

The sole horizontal well commenced production in July 1994, and quit in January 2010 after a cumulative production of 6.78 * 103m3 (Fig. 291). No reserves have assigned to the well.

6.6.1 Mission Canyon 3a B (03_43B)

This pool had a COOP well count of 6 vertical wells, with a total cumulative production of 0.16 *10^3m^3 at year end 2009 (Fig. 292). The performance of the wells has been significantly erratic, hence DCA is challenge. 1P and 2P developed reserves have been assigned as 2 years (0.55 * 10^3m^3) and 3 years (1.52 * 10^3m^3) of current production respectively. The operator assigned reserves of 3,800bbl (0.6 * 10^3m^3) is believed to be inconsistent with performance (and hence disregarded).

6.6.2 Mission Canyon 3a C (03_43C)

This pool, unit no. 10, (COOP well count of 3 vertical wells), recorded 1st oil production in July 1983. It had a total cumulative production of 25.89 * 10^3m^3 at year end 2009 (Fig. 293). The performance of the wells has been significantly erratic. The estimated 1P and 2P developed reserves are 1.98 * 10^3m^3 and 4.32 * 10^3m^3 using exponential declines of 16.70% and 8.24% per year respectively (Figures 294 - 295).

6.6.3 Mission Canyon 1 K (03_44K)

This pool (COOP well count of 5 horizontal wells), recorded 1st oil production in March 2006, and had a total cumulative production of 30.99 * 10^3m^3 at year end 2009 (Fig. 296). The wells have been erratic in their performance, with production peaking and declining repeatedly. The wells are producing at end of well (~99% water cut). Estimated 1P and 2P developed reserves are 3.07 * 10^3m^3 and 3.75 * 10^3m^3 at exponential declines of 79.19 and 69.9 percent per year respectively (Figures 297 - 298).

6.6.4 Mission Canyon 1 O (03_44O)

This pool (COOP well count of 1 vertical well), recorded 1st oil production in March 2006, and had a total cumulative production of 1.15 * 10^3m^3 at year end 2009 (Fig. 299). The well performance has been significantly erratic. Production declined from ~32bbl/day to ~7bbl/day in four months, and has been at an average of ~3.5bbl/day since mid 2008. The single meaningful decline for DCA yielded 1P = 2P developed reserves of 0.49 * 10^3m^3 at exponential declines of 31.43% per year (Fig. 300). The operator assigned reserves of 640bbl (~0.1 * 10^3m^3) is believed to be inconsistent with performance (and hence disregarded).

6.6.5 Mission Canyon 1 P (03_44P)

This pool (COOP well count of 1 vertical well), recorded 1st oil production in February 2006. It had a total cumulative oil production of 0.35 * 10^3m^3 at year end 2009 (Fig. 301). The well quit production in March 2007, and was brought back on stream in January 2010. Due to its erratic performance, the 1P and 2P developed reserves have been assigned as 2 years (0.38 * 10^3m^3) and 3 years (0.75 * 10^3m^3) respectively of current production.

7 Lulu Lake Field

The Lulu Lake field commenced oil production in January 1953 (Fig. 302), while water flooding commenced in September 1965. A total of 17 wells have been drilled in the field. The COOP well count in 2009 was 4. The field's average yearly production increased to 100.11bbl/day upon the deployment of horizontal wells in 1998, from 17.11bbl/day a year before. Its cumulative production at year end 2009 was 69.20 $*10^3m^3$ of oil, while 1P and 2P developed reserves estimates are 8.38 $* 10^3m^3$ and 18.73 $* 10^3m^3$ respectively.

7.1 Lodgepole WL A - 04_52A

This pool (COOP well count of 1 horizontal well), recorded 1st oil production in March 2003. It had a total cumulative oil production of 9.76 $* 10^3m^3$ at year end 2009 (Fig. 303). The well has produced satisfactorily with recent average rates of ~7bbl/day at high, but stable water cuts (~95%). 1P and 2P developed reserve estimates are 1.50 $* 10^3m^3$ and 2.05 $* 10^3m^3$, at exponential declines of 22.03 and 20.26 percent per year respectively (Figures 304 - 305).

7.2 Lodgepole WL A (04_52B)

This pool had a COOP well count of 3 (1 vertical and 2 horizontal), with a total cumulative oil production of 59.44 $*10^3m^3$ at year end 2009. The vertical well recorded first production in August 1984, and cumulative production of 18.36 $*10^3m^3$ at year end 2009 (Fig. 306). It produced satisfactorily till end 2005 when there was a sharp increase in water cut from ~70% to ~90%, corresponding to a sharp decline in oil rate from ~8bbl/day to ~3bbl/day. 1P and 2P developed reserves estimates are 0.66 $* 10^3m^3$ and 1.21 $* 10^3m^3$ at exponential declines of 18.45%and 6.53% per year respectively (Figures 307 - 308).

The horizontal wells recorded first production in January 1998, and had cumulative production of 41.05 $*10^3m^3$ at year end 2009 (Fig. 309). The wells have produced satisfactorily declining gently since year 2002. The 1P and 2P developed reserves estimates are 6.22 $* 10^3m^3$ and 15.47 $* 10^3m^3$ at exponential declines of 19.94% and 7.07% per year respectively (Figures 310 – 311).

8 Virden Field

The Virden field commenced oil production in August 1953 (Fig. 312), while water flooding commenced in May 1955. A total of 1213 wells have been drilled in the field. The COOP well count in 2009 was 1170. The field benefited significantly from water flooding, with average yearly production increasing to 7544bbl/day in 1965, from 2584 bbl/day a year earlier; and deployment of horizontal well technology, with average yearly production increasing to 4088bbl/day in 1998, from 3597bbl/day a year before. The field's cumulative production at year end 2009 was 24.0 $*10^6m^3$ of oil. 1P and 2P developed reserves estimates are 1.45 * 10^6m^3 and 2.17 * 10^6m^3 respectively.

8.1 Lodgepole A - 05_59A

A total of 425 wells have been drilled in this pool, 248 of which were classified as COOP (198 vertical and 54 horizontal) in 2009, 76 of the wells were water injection wells. First oil production from the pool was in December 1953, while water flooding commenced in December 1957. The pool recorded a total cumulative oil production of 12.56 * 10^6m^3 at year end 2009 (Fig. 313). 1P and 2P developed reserve estimates are 822.68 * 10^3m^3 and 1203.62 * 10^3m^3.

8.1.1 Lodgepole A - 05_59A (Non-Unitized)

This non-unitized wells had a COOP well count of 52 (40 vertical and 12 horizontal), and a total cumulative oil production of >841 $*10^3m^3$ at year end 2009. The vertical wells recorded first production in August 1955, and had a cumulative production of 685 $*10^3m^3$ at year end 2009 (Fig. 314). 1P and 2P developed reserves estimates are 40.88 * 10^3m^3 and 51.34 * 10^3m^3 at exponential declines of 8.42 and 5.50 percent per year respectively (Figures 315 - 316).

The horizontal wells recorded first production in September 1996, and had cumulative production of >156 $*10^3m^3$ at year end 2009 (Fig. 312). The wells have produced satisfactorily, peaking and declining repeatedly with increase in well count. 1P and 2P developed reserves estimates are 58.0 * 10^3m^3 and 65.90 * 10^3m^3 at exponential declines of 21.4% and 18.98% per year respectively (Figures 318 – 319)

8.1.2 Lodgepole A - 05_59A (Unit 1)

The unit no. 1 wells had a COOP well count of 184 (150 vertical and 34 horizontal), with a total cumulative oil production of >9224 $*10^3m^3$ at year end 2009. The vertical wells recorded first production in December 1953, and cumulative production of >8850 $*10^3m^3$ at year end 2009 (Fig. 320). The wells have produced with a gentle decline, at stable water cut building up to the present >90%. The 1P and 2P developed reserves estimates are 434.39 * 10^3m^3 and 678.58 * 10^3m^3 using exponential declines of 6.30 and 4.21 percent per year respectively (Figures 321 - 322).

The horizontal wells recorded first production in October 1996, and cumulative production of >375 $*10^3m^3$ at year end 2009 (Fig. 323). The wells have produced satisfactorily peaking and declining at times, at stable water cut >90%. The 1P and 2P developed reserves estimates are 276.81 * 10^3m^3 and 385.54 * 10^3m^3 using exponential declines of 15.37 and 11.0 percent per year respectively (Figures 324 – 325)

8.1.3 Lodgepole A - 05_59A (Unit 2)

The unit no. 2 wells had a COOP well count of 11 (8 vertical and 4 horizontal), with a total cumulative oil production of >160 $*10^3m^3$ at year end 2009. The vertical wells recorded first production in February 1983, and cumulative production of >82.39 $*10^3m^3$ at year end 2009 (Fig. 326). The wells have produced satisfactorily with a gentle decline since inception.

Production spiked to ~550bbl/day in 1990, but declined immediately to the pre-spike rate of <100bbl/day. 1P and 2P developed reserve estimates are 5.91 * 10^3m^3 and 12.03 * 10^3m^3 using exponential declines of 16.85 and 8.4 percent per year respectively (Figures 327 - 328).

The horizontal wells recorded first production in October 1996, and had cumulative production of >77 *10^3m^3 at year end 2009 (Fig. 329). The wells have produced satisfactorily though at stable water cut >90%, peaking and declining at times. 1P and 2P developed reserves estimates are 6.69 * 10^3m^3 and 10.24 * 10^3m^3 using exponential declines of 16.85 and 8.4 percent per year respectively (Figures 330 – 331)

8.2 Lodgepole B - 05_59B

A total of 506 wells have been drilled in this pool, 211 of which were classified as COOP (176 vertical and 35 horizontal), in 2009, 83 of the wells were water injectors. First oil production was in August 1953, while water flooding commenced in May 1956. The pool recorded a total cumulative oil production of >5.50 * 10^6m^3 at year end 2009 (Fig. 332). 1P and 2P developed reserve estimates are 415.08 * 10^3m^3 and 620.12 * 10^3m^3.

8.2.1 Lodgepole B - 05_59B (Non-Unitized)

The non-unitized wells had a COOP well count of 33 (31 vertical and 2 horizontal), with a total cumulative oil production of >537 *10^3m^3 at year end 2009. The vertical wells recorded first production in August 1953, and had cumulative production of >531 *10^3m^3 at year end 2009 (Fig. 333). 1P and 2P developed reserves estimates are 40.88 * 10^3m^3 and 51.34 * 10^3m^3 at exponential declines of 9.6% and 6.58% per year respectively (Figures 334 - 335).

The horizontal wells recorded first production in March 2007, and had a cumulative production of 4.86 *10^3m^3 at year end 2009 (Fig. 336). 1P and 2P developed reserve estimates are 4.53 * 10^3m^3 (consistent with 3 years of production at current rate), and 10.97 * 10^3m^3 at exponential declines of 22.61% and 10.51% per year respectively (Figures 337 – 338)

8.2.2 Lodgepole B - 05_59B (Unit 1)

The unit no. 1 wells had a COOP well count of 73 (54 vertical and 19 horizontal), and a total cumulative oil production of >2131 *10^3m^3 at year end 2009. The vertical wells recorded first production in April 1954, and had cumulative production of >2002 *10^3m^3 at year end 2009 (Fig. 339). The wells produced at an average rate of ~300bbl/day from 2002 to 2008. Productivity has been on the decline since after, coinciding with increasing downtime in the wells. The 1P and 2P developed reserve estimates are 79.98 * 10^3m^3 and 128.65 * 10^3m^3 at exponential declines of 9.8% and 9.78% per year respectively (Figures 340 - 341).

The horizontal wells recorded first production in October 1997, and had cumulative production of >128 *10^3m^3 at year end 2009 (Fig. 342). The wells have produced satisfactorily at stable water cut >90%, peaking and declining at times. 1P and 2P developed reserves estimates are 101.01 * 10^3m^3 and 167.85 * 10^3m^3 at exponential declines of 17.66% and 10.72% percent per year respectively (Figures 343 – 344)

8.2.3 Lodgepole B - 05_59B (Unit 2)

The unit no. 2 wells had a COOP well count of 33 (29 vertical and 4 horizontal), and a total cumulative oil production of >825 *10^3m^3 at year end 2009. The vertical wells recorded first production in February 1959, and had cumulative production of >802 *10^3m^3 at year end 2009 (Fig. 345). The wells have produced satisfactorily with a gentle decline since 1973 when production spiked to ~700bbl/day. The 1P and 2P developed reserve estimates are 69.02 * 10^3m^3 and 92.84 * 10^3m^3 at exponential declines of 9.48% and 7.41% percent per year respectively (Figures 347 - 347).

The horizontal wells recorded first production in October 1997, and had cumulative production of >23 $*10^3m^3$ at year end 2009 (Fig. 348). 1P and 2P developed reserve estimates are 12.39 * 10^3m^3 and 36.22 * 10^3m^3 at exponential declines of 13.53% and 4.67% percent per year respectively (Figures 349 – 350)

8.2.4 Lodgepole B - 05_59B (Unit 3)

The unit no. 3 wells had a COOP well count of 72 (62 vertical and 10 horizontal) out of 129 wells, and had a total cumulative production of >2000 $*10^3m^3$ at year end 2009. Productivity increased from ~500bbl/day to 1200bbl/day in 1967, with increase in yearly average monthly water injection from ~100,000bbl/day in 1966 to ~1,200,000bbl/day. The vertical wells recorded first production in November 1954, and had a cumulative production of >1960 $*10^3m^3$ at year end 2009 (Fig. 351). The wells have produced satisfactorily with a gentle decline since 1967 when production spiked to ~1200bbl/day. 1P and 2P developed reserves estimates are 115.43 * 10^3m^3 and 138.69 * 10^3m^3 at exponential declines of 8.27 and 6.77 percent per year respectively (Figures 352 - 353).

The horizontal wells recorded first production in August 2001, and cumulative production of >41 $*10^3m^3$ at year end 2009 (Fig. 354). The wells have produced satisfactorily peaking at ~370bbl/day, at stable water cut >90%. The 1P and 2P developed reserves estimates are 14.14 * 10^3m^3 and 17.80 * 10^3m^3 using exponential declines of 24.55 and 18.96 percent per year respectively (Figures 355 – 356)

8.3 Lodgepole C - 05_59C

A total of 193 wells have been drilled in this pool, 93 of which were classified as COOP (59 vertical and 34 horizontal), in 2009; 83 of the wells were water injectors. First oil production from the pool was in June 1955, while water flooding commenced in March 1956. The pool recorded a total cumulative oil production of 2.80 * 10^6m^3 at year end 2009 (Fig. 357). Its total 1P and 2P developed reserve estimates are 179.51 * 10^3m^3 and 285.43 * 10^3m^3.

8.3.1 Lodgepole C - 05_59C (Non-Unitized)

The non-unitized had a COOP well count of 23 (16 vertical and 7 horizontal), with a total cumulative oil production of >230 $*10^3m^3$ at year end 2009. The vertical wells recorded first production in December 1985, and cumulative production of >173 $*10^3m^3$ at year end 2009 (Fig. 358). 1P and 2P developed reserves estimates are 15.31 * 10^3m^3 and 19.60 * 10^3m^3 at exponential declines of 11.09% and 8.59% per year respectively (Figures 359 - 360).

The horizontal wells recorded first production in March 1993, and had cumulative production of 56.65 $*10^3m^3$ at year end 2009 (Fig. 361). The wells' performance is characterized by repeated peak and declines. The 1P and 2P developed reserve estimates are 64.53 * 10^3m^3 and 100.67 * 10^3m^3 at exponential declines of 45.39% and 15.64% per year respectively (Figures 362 – 363)

8.3.2 Lodgepole C - 05_59C (Unit 1)

The unit no. 1 had a COOP well count of 70 (43 vertical and 27 horizontal), and a total cumulative oil production of >1555 $*10^3m^3$ at year end 2009. The vertical wells recorded first production in June 1955, and cumulative production of >1325 $*10^3m^3$ at year end 2009 (Fig. 364). The wells have produced satisfactorily. 1P and 2P developed reserve estimates are 79.98 * 10^3m^3 and 128.65 * 10^3m^3 at exponential declines of 42.46 and 53.99 percent per year respectively (Figures 365 - 366).

The horizontal wells recorded first production in August 1997, and cumulative production of >230 $*10^3m^3$ at year end 2009 (Fig. 367). The wells have had satisfactory production at stable water cut >90%, peaking and declining at times. The 1P and 2P developed reserves estimates are 57.21 $* 10^3m^3$ and 111.18 $* 10^3m^3$ at exponential declines of 37.36% and 18.98% per year respectively (Figures 368 – 369)

8.4 Lodgepole D - 05_59D

A total of 42 wells have been drilled in this pool, 12 of which were classified as COOP (6 vertical and 6 horizontal) in 2009; 9 of the wells were water injectors. First oil production from the pool was in January 1964, while water flooding commenced in November 1972. The pool productivity was boosted by the deployment of horizontal well technology in November 2002, as average yearly production increased from 55.56bbl/day to 163.26bbl/day in 2003. Total cumulative production was 0.66 $* 10^6m^3$ at year end 2009 (Fig. 370). 1P and 2P developed reserve estimates are 29.41 $* 10^3m^3$ and 65.24 $* 10^3m^3$.

8.4.1 Lodgepole D - 05_59D (Non-Unitized)

The non-unitized wells had a COOP well count of 6 (3 vertical and 3 horizontal), and a total cumulative oil production of >108 $*10^3m^3$ at year end 2009. The vertical wells recorded first production in June 1964, and had a cumulative production of >173 $*10^3m^3$ at year end 2009 (Fig. 371). Production recently declined from ~60bbl/day (2004) to ~20bbl/day (2005), due to increasing water cut. This trend has persisted as water cut has increased from ~75% to >90%. The 1P and 2P developed reserves estimates are 2.23 $* 10^3m^3$ and 5.97 $* 10^3m^3$ at exponential declines of 16.87 and 7.28 percent per year respectively (Figures 372 - 373).

The horizontal wells recorded first production in February 2002, and had cumulative production of 25.71 $*10^3m^3$ at year end 2009 (Fig. 374). The wells' performance has been satisfactory. 1P and 2P developed reserves estimates are 3.77 $* 10^3m^3$ and 5.18 $* 10^3m^3$ at exponential declines of 27.01 and 17.27 percent per year respectively (Figures 375 – 376)

8.4.2 Lodgepole D - 05_59D (Unit 1)

The unit no. 1 had 6 horizontal wells, with a total cumulative oil production of >61 $* 10^3m^3$ at year end 2009 (Fig. 377). The unit recorded first production in November 2002, and the wells have produced satisfactorily since after. The 1P and 2P developed reserves estimates are 23.41 $* 10^3m^3$ and 54.09 $* 10^3m^3$ at exponential declines of 19.99 and 9.03 percent per year respectively (Figures 378 – 379).

9 Whitewater Field

The Whitewater field commenced oil production in October 1953 (Fig. 381), while water flooding commenced in January 1973. A total of 72 wells have been drilled in the field. The COOP and injector well count in 2009 was 45 and 6 respectively. The field's cumulative production at year end 2009 was 600 $*10^3m^3$ of oil, while 1P and 2P developed reserves estimates are 62.37 $* 10^6m^3$ and 92.92 $* 10^6m^3$ respectively.

9.1 Lodgepole WL A - 06_52A

A total of 18 wells have been drilled in this pool, 9 of which were classified as COOP (2 vertical and 7 horizontal) in 2009; 2 of the wells were water injection wells. First oil production from the pool was in October 1953, while water flooding commenced in January 1973. The pool's total cumulative oil production was 210 $* 10^3m^3$ at year end 2009.

The vertical wells recorded first production in November 1998, and had cumulative production of >12.88 $*10^3m^3$ at year end 2009 (Fig. 382). The wells' performance is characterized by repeated peaks and declines. 1P and 2P developed reserves estimates are 0.66 $* 10^3m^3$ and 0.68 $* 10^3m^3$ at exponential declines of 45.99 and 34.55 percent per year respectively (Figures 383 - 384).

The horizontal wells recorded first production in February 2000, and had a cumulative production of >68 $*10^3m^3$ at year end 2009 (Fig. 385). The wells have produced satisfactorily. The 1P and 2P developed reserves estimates are 7.79 $* 10^3m^3$ and 13.96 $* 10^3m^3$ using exponential declines of 31.19% and 19.58% per year respectively (Figures 386 – 387)

9.2 Lodgepole WL B - 06_52B

A total of 37 wells have been drilled in this pool, 28 of which were classified as COOP (23 vertical and 5 horizontal) in 2009. First oil production was in May 1982. The pool's total cumulative oil production was 290 $* 10^3m^3$ at year end 2009. The vertical wells recorded first production in May 1982, and cumulative production of >217 $*10^3m^3$ at year end 2009 (Fig. 388). The wells have had satisfactory performances. The 1P and 2P developed reserves estimates are 28.38 $* 10^3m^3$ and 43.98 $* 10^3m^3$ at exponential declines of 9.1 and 6.97 percent per year respectively (Figures 389 - 390).

The horizontal wells recorded first production in February 2000, and cumulative production of >54 $*10^3m^3$ at year end 2009 (Fig. 391). The wells have produced satisfactorily. 1P and 2P developed reserves estimates are 5.51 $* 10^3m^3$ and 6.83 $* 10^3m^3$ at exponential declines of 25.27 and 19.77 percent per year respectively (Figures 392 – 393)

9.3 Lodgepole WL C - 06_52C

A total of 8 wells have been drilled in this pool, all of which were still classified as COOP in 2009. First oil production was in October 2004. The pool's total cumulative oil production was 0.11 $* 10^6m^3$ at year end 2009. The vertical wells recorded first production in September 2004, and had cumulative production of >217 $*10^3m^3$ at year end 2009 (Fig. 394). The 1P and 2P developed reserves estimates are 0.88 $* 10^3m^3$ and 1.64 $* 10^3m^3$ at exponential declines of 44.07 and 24.7 percent per year respectively (Figures 395 - 396).

The horizontal wells recorded first production in August 2005, and had a cumulative production of >96 $*10^3m^3$ at year end 2009 (Fig. 397). The 1P and 2P developed reserves estimates are 19.16 $* 10^3m^3$ and 25.84 $* 10^3m^3$ at exponential declines of 25.27 and 19.77 percent per year respectively (Figures 398 – 399)

10 Pierson Field

The Pierson field commenced oil production in February 1954 (Fig. 400); water flooding commenced in December 1958. A total of 493 wells have been drilled in the field. The COOP well count in 2009 was 295. The field benefited significantly from the deployment of horizontal well technology, with average yearly production increasing to 2133bbl/day in 2006, from 1420bbl/day a year earlier. The field's cumulative production at year end 2009 was 2.31 $*10^6m^3$ of oil, while 1P and 2P developed reserves estimates are 344.35 * 10^3m^3 and 666.17 * 10^3m^3 respectively.

10.1 Lower Amaranth B (07_29B)

A total of 58 wells have been drilled, 45 of which were classified as COOP (32 vertical and 13 horizontal) in 2009. The pool's total cumulative production was 73.84 * 10^3m^3 at year end 2009. The vertical wells recorded first production in June 1982, and cumulative production of >45.91 $*10^3m^3$ at year end 2009 (Fig. 401). The wells' performance has been satisfactory, with water cut decreasing from >80% to ~25% in 2009 before increasing again. The 1P and 2P developed reserves estimates are 11.87 * 10^3m^3 and 15.37 * 10^3m^3 using exponential declines of 34.63 and 27.65 percent per year respectively (Figures 402 - 403).

The horizontal wells recorded first production in January 2006, and had cumulative production of >15.38 $*10^3m^3$ at year end 2009 (Fig. 404). The wells have produced satisfactorily, with occasional peaks and declines. The last production showed a rate decline hence the 1P DCA was based on the last rate of 85bbl/day, which assumes that production does not return to its pre-decline rate. The 2P DCA assumes that production returns to the pre-decline rate of ~105bbl/day. Hence, 1P and 2P developed reserves estimates of 9.30 * 10^3m^3 and 11.57 * 10^3m^3, at the same exponential decline of 43.37% per year (Figures 405 – 406)

10.2 Lower Amaranth J (07_29J)

A total of 13 wells have been drilled in the pool; 4 of them were COOP (all vertical) in 2009. First oil production from the pool was in July 1990. The pool's total cumulative oil production was 9.68 * 10^3m^3 at year end 2009 (Fig. 407). The wells have historically recorded an average rate of >10bbl/day. Due to this low rate, the 1P = 2P developed reserves estimates is 1.41 * 10^3m^3 using exponential decline of 23.26% per year (Fig. 408).

10.3 Lower Amaranth – Mission Canyon 3b A (07_35A)

A total of 243 wells have been drilled, 163 of which were COOP (152 vertical and 11 horizontal) in 2009; 65 of the wells were water injectors. First oil production was in December 1985. Water flooding commenced in October 1992, boosting the pool's average yearly production from 816bbl/day (1992) to 1114bbl/day. With horizontal well technology in 1993, the pool's average yearly production was boosted to 1626bbl/day in 1994. Total cumulative production was 1.10 * 10^6m^3 at year end 2009 (Fig. 409). 1P and 2P developed reserve estimates are 174.74 * 10^3m^3 and 395.33 * 10^3m^3.

10.3.1 Lower Amaranth – Mission Canyon 3b A (Non-Unitized)

This non-unitized wells had a COOP well count of 86 (78 vertical and 8 horizontal) out of a total of 100, and a total cumulative production of 373.32 $*10^3m^3$ at year end 2009. The vertical wells recorded first production in September 1986, and had cumulative production of >297 $*10^3m^3$ at year end 2009 (Fig. 410). The wells have produced satisfactorily, with water cut stable at ~80% between 1987 and 2007. A decrease in water cut was subsequently noticed due dry oil from new wells. 1P and 2P developed reserves estimates are 49.95 * 10^3m^3 and

105.65 * 10^3m^3 using exponential declines of 27.45 and 13.09 percent per year respectively (Figures 411 - 412).

The horizontal wells recorded first production in July 1993, and had cumulative production of >73 *10^3m^3 at year end 2009 (Fig. 413). There was a recent increase in the production of the wells from ~40bbl/day to ~150bbl/day, and at satisfactory water cut levels. The DCA assumed that the sustainable rate was 120bbl/day. Hence, the 1P and 2P developed reserves estimates are 17.73 * 10^3m^3 and 33.92 * 10^3m^3 at exponential declines of 31.44 and 18.09 percent per year respectively (Figures 414 – 415)

10.3.2 Lower Amaranth – Mission Canyon 3b A (Unit 1)

The unit no. 1 wells had a COOP well count of 77 (74 vertical and 3 horizontal) out of a total of 143, and a total cumulative oil production of 723.23 *10^3m^3 at year end 2009. The vertical wells recorded first production in March 1993, and had a cumulative production of >484 *10^3m^3 at year end 2009 (Fig. 416). The wells have produced with a stable production averaging ~400bbl/day, between 1996 and 2005. Thereafter, production spiked to ~1050bbl/day with further drilling, and has since been declining gently. The 1P and 2P developed reserves estimates are 105.42 * 10^3m^3 and 252.48 * 10^3m^3 at exponential declines of 21.52 and 9.28 percent per year respectively (Figures 417 - 418).

The horizontal wells recorded first production in December 1993, and had cumulative production of >15 *10^3m^3 at year end 2009 (Fig. 419). The wells have produced at an average of ~10bbl/day till 2007, when production spiked to ~150bbl/day and dropped sharply to ~60bbl/day followed by a more realistic decline. The 1P and 2P developed reserves estimates are 1.64 * 10^3m^3 and 3.27 * 10^3m^3 at exponential declines of 41.19% and 22.47% per year respectively (Figures 420 – 421)

10.4 Lower Amaranth – Mission Canyon 3b C (07_35C)

A total of 4 wells have been drilled in the pool, 3 of which were COOP (2 vertical and 1 horizontal) in 2009. The pool's total cumulative oil production was 10.83 * 10^3m^3 at year end 2009. The 1P = 2P developed reserve estimates is 2.0 * 10^3m^3. The first vertical well in this pool was brought on stream in January 1963, and died eight months later. The second was brought on stream in July 1985. Its total cumulative production was 9.91 *10^3m^3 at year end 2009 (Fig. 422). The 1P and 2P developed reserves estimates are 1.42 * 10^3m^3 and 1.43 * 10^3m^3 at exponential declines of 13.11 and 12.54 percent per year respectively (Figures 423 - 424).

The sole horizontal well recorded first production in August 2008 at ~60bbl/day. Its rate declined to ~10bbl/day, with cumulative production of 1.93 *10^3m^3 at year end 2009 (Fig. 425). Due to sparsity of data, the 1P DCA was equated the 2P. Hence, 1P = 2P developed reserves estimates of 0.57 * 10^3m^3, at exponential decline of 38.71% per year (Figures 425 – 426).

10.5 Lower Amaranth – Mission Canyon 3 C (07_41C)

A total of 9 wells have been drilled on this pool, 6 of which were COOP (all horizontal) in 2009; 1 of the wells was a water injector. First oil production from the pool was in August 1995. Water flooding commenced in September 1998. Total cumulative oil production was 91.84 * 10^3m^3 at year end 2009 (Fig. 427). The 1P and 2P developed reserve estimates are 4.92 * 10^3m^3 and 10.16 * 10^3m^3, at exponential declines of 23.39 and 12.32 percent per year respectively (Figures 428 - 429).

10.6 Lower Amaranth – Mission Canyon 3b B (07_42B)

A total of 27 wells have been drilled in the pool, 11 of which were classified as COOP (4 vertical and 7 horizontal) in 2009. The pool's total cumulative oil production was 188.26 * 10^3m^3 at year end 2009. The vertical wells recorded first production in November 1993. The wells have produced satisfactorily. The last drilling campaign in 1994 resulted in a spike in production to ~80bbl/day followed by a sharp decline about a year later. Production in the last 5 years has averaged ~5bbl/day. The total cumulative production was 81.6 *10^3m^3 at year end 2009 (Fig. 430). The 1P and 2P developed reserves estimates are 1.62 * 10^3m^3 and 2.40 * 10^3m^3 at exponential declines of 13.35% and 9.41% per year respectively (Figures 431 - 432).

The horizontal wells recorded first production in August 1994. A drilling campaign in 1998 saw production jump from ~150bbl/day to ~340bbl/day. Another increase in well count in 2006 resulted in production boost from ~55bbl/day to ~200bbl/day. Production is currently averaging ~70bbl/day; with a cumulative production of 106.7 *10^3m^3 at year end 2009 (Fig. 433). 1P and 2P developed reserves estimates are 18.04 * 10^3m^3 and 65.22 * 10^3m^3 at exponential declines of 17.15 and 5.05 percent per year respectively (Figures 434 - 435).

10.7 Lower Amaranth – Mission Canyon 3b C (07_42C)

A total of 2 vertical wells have been drilled on this pool, both of which were COOP in 2009. First oil production from the pool was in March 1986; total cumulative oil production was 10.84 * 10^3m^3 at year end 2009 (Fig. 436). The 1P and 2P developed reserve estimates are 1.72 * 10^3m^3 and 2.33 * 10^3m^3, at exponential declines of 11.52 and 7.88 percent per year respectively (Figures 437 - 438).

10.8 Lower Amaranth – Mission Canyon 3b E (07_42E)

A total of 17 wells have been drilled in this pool; 9 of them were COOP (2 vertical and 7 horizontal) in 2009. The pool's total cumulative oil production was 113.23 * 10^3m^3 at year end 2009. The vertical wells recorded first production in January 1988. The wells produced satisfactorily, averaging ~42bbl/day between 1988 and 2001. Production has declined to an average of ~10bbl/day since then owing to an increase in water cut. Total cumulative production was 69.5 *10^3m^3 at year end 2009 (Fig. 439). The 1P and 2P developed reserves estimates are 1.69 * 10^3m^3 and 2.45 * 10^3m^3 at exponential declines of 12.02 and 8.58 percent per year respectively (Figures 440 - 441).

The horizontal wells recorded first production in August 2001. Further drilling in 2008, saw production jump from ~35bbl/day to ~300bbl/day. Production declined sharply decline to the current ~115bbl/day after a cumulative production of 43.73 *10^3m^3 at year end 2009 (Fig. 442). 1P and 2P developed reserves estimates are 29.15 * 10^3m^3 and 29.29 * 10^3m^3 at exponential declines of 20.04 and 20.01 percent per year respectively (Figures 443 - 444).

10.9 Lower Amaranth – Mission Canyon 3b F (07_42F)

A total of 3 wells have been drilled in the pool, (2 vertical and 1 horizontal) in 2009. Only the horizontal well was COOP in 2009. First production in this pool was in July 1961, and total cumulative oil production was 7.08 * 10^3m^3 at year end 2009. The sole producing horizontal well commenced production in March 2009. Production has declined from the initial ~24bbl/day to the current ~2bbl/day (Fig. 445). Due to the observed recent sharp decline, and the uncertainty about how long the wells can sustain production afterwards, the 1P has been set equal to 2P. Hence, the 1P =2P developed reserves estimates are 0.14 * 10^3m^3 using exponential decline of 62.81% per year (Fig. 446). No reserves are assigned by the Operator to these wells.

10.10 Lower Amaranth – Mission Canyon 3b L (07_42L)

A total of 3 wells have been drilled in the pool, all of which were COOP (1 vertical and 2 horizontal) in 2009. The pool's total cumulative oil production was 3.43 * 10^3m^3 at year end 2009. The vertical well recorded first production in August 2008, and peaked at 13.3bbl/day a month later. Production has since declined to ~2bbl/day after a cumulative production of 0.43 *10^3m^3 at year end 2009 (Fig. 447). There is no discernible decline for DCA; the attempted DCA (Fig. 448) resulted in an unrealistically low EUR of 0.52 *10^3m^3 (reserve of 0.09 *10^3m^3) at an exponential decline of 55.91% per year. Hence the Operator advised 1P and 2P developed reserves estimates of 0.42 * 10^3m^3 and 0.78 * 10^3m^3 are carried for the well.

The horizontal wells recorded first production in August 2009, and peaked at 195bbl/day a month later. Production has since declined to ~75bbl/day after a cumulative production of 3.0 *10^3m^3 at year end 2009 (Fig. 449). There is no discernible decline for DCA. Hence the Operator advised 1P and 2P developed reserves estimates of 23.59 * 10^3m^3 and 31.89 * 10^3m^3 are carried for the wells.

10.11 Lower Amaranth – Mission Canyon 3a A (07_43A)

A total of 13 wells have been drilled in the pool; 4 of them were COOP (all vertical) in 2009. There has been water flooding in the pool through one well since July 1993. The pool's total cumulative oil production was 56.94 * 10^3m^3 at year end 2009. Production from the pool commenced in January 1955, and lasted for only 9 months. Production resumed in August 1974, and increased to a peak of ~130bbl/day, before declining to a low of 1.74bbl/day in February 1983, due to a drop in producing well count from 5 to 2. The well count was restored in late 1984, thus restoring production to an average of 45bbl/day by 1985 (Fig. 450). A new well in 1990 boosted production from ~40bbl/day to ~70bbl/day before decline set in again, with production averaging ~3.63bbl/day in 2009, owing to increase in water cut. 1P and 2P developed reserves estimates are 1.27 * 10^3m^3 and 1.97 * 10^3m^3 at exponential declines of 12.33% and 8.21% per year respectively (Figures 451 - 452).

10.12 Lower Amaranth – Mission Canyon 3a B (07_43B)

A total of 57 wells have been drilled in the pool, 28 of which were COOP (14 vertical and 14 horizontal) in 2009. There has been water flooding in the pool through two wells since July 1979. The pool's total cumulative oil production was 408.36 * 10^3m^3 at year end 2009. The vertical wells commenced production in November 1965, and peaked at ~305bbl/day in November 1968 (Fig. 453). The wells have recorded satisfactory performance. The 1P and 2P developed reserves estimates are 3.83 * 10^3m^3 and 4.60 * 10^3m^3 at exponential declines of 12.09 and 8.41 percent per year respectively (Figures 454 - 455).

The horizontal wells recorded first production in March 1996. Further drilling in 2007 brought production to a peak of ~470bbl/day. Production has been satisfactory since after leading a cumulative production of >123 *10^3m^3 at year end 2009 (Fig. 456). 1P and 2P developed reserves estimates are 35.22 * 10^3m^3 and 52.95 * 10^3m^3 at exponential declines of 29.72 and 20.03 percent per year respectively (Figures 457 - 458).

10.13 Lower Amaranth – Mission Canyon 3a C (07_43C)

A total of 16 wells have been drilled in the pool, 6 of which were COOP (2 vertical and 4 horizontal) in 2009. One well served as injector since December 1958. The pool's total cumulative oil production was 408.36 * 10^3m^3 at year end 2009. The vertical wells commenced production in January 1954, and had a peak of 105bbl/day after a few months (Fig. 459). Production declined, and averaged 15bbl/day, from 1962 to 1984, and declined further to an average of ~10bbl/day till end of 2009. The wells have experienced frequent down time. The 1P and 2P developed reserves estimates are 3.83 * 10^3m^3 and 4.60 * 10^3m^3 at exponential declines of 5.49% and 4.98% per year respectively (Figures 460 - 461).

The horizontal wells recorded first production in September 1995. Further drilling in 1998 brought production to a peak of ~350bbl/day. Production has been satisfactory since after leading a cumulative production of >70 *10^3m^3 at year end 2009 (Fig. 462). 1P and 2P developed reserves estimates are 6.83 * 10^3m^3 and 13.97 * 10^3m^3 at exponential declines of 20.47 and 10.36 percent per year respectively (Figures 463 - 464).

10.14 Lower Amaranth – Mission Canyon 3a E (07_43E)

There is only one well (COOP) completed in this pool. Its cumulative production was 2.07 * 10^3m^3 at year end 2009; production commenced in February 1997 (Fig. 465). There is a fair degree of frequent down time associated with the well. The 1P and 2P developed reserves estimates are 0.43 * 10^3m^3 and 0.62 * 10^3m^3 at exponential declines of 20.47 and 10.36 percent per year respectively (Figures 466 – 467).

11 Kirkella Field

The Kirkella field commenced oil production in July 1955 (Fig. 468). A total of 86 wells have been drilled / completed in the field; 39 of them were classified as COOP wells and 13 as water injectors in 2009. The commencement of water flooding in April 1958 resulted in a boost in production from a yearly average of ~70bbl/day in 1957 to ~290bbl/day in 1959 before production decline set in. Increase in producing well count resulted in a production boost from a yearly average of ~174bbl/day in 1979, to ~450bbl/day in 1982. Further field development again yielded a production boost from a yearly average of ~160bbl/day in 1998 to ~620bbl/day in 2000. The field's cumulative production at year end 2009 was 487.56 $*10^3m^3$ of oil. 1P and 2P developed reserves estimates are 44.24 * 10^3m^3 and 59.91 * 10^3m^3 respectively.

11.1 Lodgepole Daly A (09_54A)

There have been a total of 26 well verticals completed in this pool (13 COOP in 2009); two of them were water injectors. Total cumulative production was 217.43 * 10^3m^3 at year end 2009. Production commenced in January 1957 (Fig. 469). The 2009 average performance of the wells was 13bbl/day and water cut was >99%. 1P and 2P developed reserves estimates are 23.58 * 10^3m^3 and 21.36 * 10^3m^3 at exponential declines of 19.18 and 13.34 percent per year respectively (Figures 470 – 471).

11.2 Lodgepole Daly B (09_54B)

A total of 15 wells have been completed in this pool; 8 of them were COOP (all vertical) and 2 water injectors in 2009. The pool's total cumulative oil production was 59.47 * 10^3m^3 at year end 2009. Production commenced in July 1955, and lasted for only 16 months (Fig. 472). Production resumed in June 1978, and increased to a peak of ~22bbl/day in May 1980, before declining till all 5 remaining producers quit in August 2006. Production was restored in October 2006, but all 5 wells died again in March 2007. One well was restored to production in July 2007, but it quit in April 2009 and has not produced since then, hence no reserves are assigned to these wells as there is yet no clear plan to restore them back to production

11.3 Lodgepole Daly C (09_54C)

A total of 19 wells have been completed in this pool; 10 of them were COOP wells (all vertical), and 4 water injectors, in 2009. The pool's total cumulative oil production was 95.52 * 10^3m^3 at year end 2009. Production from the pool commenced in November 1980, and increased to a peak of ~440bbl/day in February 1982 (Fig. 473). The 2009 average performance of the wells was ~19bbl/day and water cut was >99%. 1P and 2P developed reserves estimates are 3.21 * 10^3m^3 and 6.48 * 10^3m^3 at exponential declines of 21.44 and 12.56 percent per year respectively (Figures 474 – 475).

11.4 Lodgepole Crinoidal B (09_55B)

Two wells (both COOP) have been completed in this pool, with total cumulative production of 40.95 * 10^3m^3 at year end 2009. Production commenced in October 1999, and increased to a peak of ~560bbl/day within two months (Fig. 476) before declining till the single producer at the time, quit production in March 2003. Production was restored a year later, and increased to another peak of ~290bbl/day in July 2006 before declining again. The 2009 average performance of the wells was ~100bbl/day and water cut was ~20%, with a recent increase in production from ~80bbl/day to >100bbl/day. As this recent increase in production is yet to be established with sustained production, the 1P DCA assumed that the 100bbl/day was not sustainable, while the 2P DCA assumed that jump in rate to >100bbl/day was sustained. This resulted in 1P and 2P developed reserves estimates of 12.71 * 10^3m^3 and 15.66 * 10^3m^3 at the same exponential decline of 31.36% per year (Figures 477 – 478).

11.5 Lodgepole Crinoidal B (09_55B)

Three wells (2 COOP) have been completed in this pool, with total cumulative oil production of 50.37 * 10^3m^3 at year end 2009. Water flood (1 injector) commenced in July 2000, and lasted for two months. Production from the pool commenced in November 1999, and increased to a peak of ~100bbl/day in October 1959 (Fig. 479) before declining till the single producer at the time quit production in January 1969. Production was restored three months later, and remained fairly stable till it quit production again in September 1998. Production was again restored in November 2001, and remained at a yearly average of ~40bbl/day until 2007, and declined to ~16bbl/day at end 2009. 1P and 2P developed reserves estimates are 3.73 * 10^3m^3 and 4.0 * 10^3m^3 at exponential declines of 21.51% and 19.31% per year (Figures 480 – 471).

12 Souris Hartney Field

The Souris Hartney field commenced oil production in November 1993 (Fig. 485). A total of 15 wells have been completed in the field, 11 of which were counted as COOP wells in 2009. There has been no water flooding in this field. The field performance is characterized by repeated cycles of peaks and declines. Further field development yielded a production boost from a yearly average of ~169bbl/day in 2005 to ~273bbl/day in 2006. The field's cumulative production at year end 2009 was 138.24 $*10^3m^3$, while 1P and 2P developed reserves estimates are 40.50 * 10^3m^3 and 53.69 * 10^3m^3 respectively.

12.1 Lodgepole Virden A (10_53A)

Eleven wells (all COOP) have been completed in this pool, with total cumulative oil production of 70.71 * 10^3m^3 at year end 2009. Production from the pool commenced in March 2003, and increased to a peak of ~483bbl/day in 2006 (Fig. 486). The pool performance has historically been repeated peaks and declines, and averaged ~30bbl/day in 2009. The 1P and 2P developed reserves estimates are 32.65 * 10^3m^3 and 35.01 * 10^3m^3 at exponential declines of 19.27% and 18.18% per year (Figures 487 – 488).

12.2 Lodgepole Virden A - 10_53A (Unit 1)

Four wells (all COOP) have been completed in this pool/unit, with total cumulative oil production of 67.53 * 10^3m^3 at year end 2009. Production from the pool commenced in November 1993, and has been repeated peaks and declines with peak production of ~240bbl/day in 2006 (Fig. 489) and average 2009 production of ~26bbl/day. The 1P and 2P developed reserves estimates are 7.95 * 10^3m^3 and 18.68 * 10^3m^3 from exponential declines of 12.2% and 5.6% per year (Figures 490 – 491).

13 Coulter Field

The Coulter field commenced production in November 1952 (Fig. 492), and produced till February 1958. A total of 18 wells have been completed in the field, 5 of which were counted as COOP wells in 2009 and 3 as water injectors. Production resumed in December 1982. The average 2009 calendar day production was 1.8bbl/day. The field's cumulative production at year end 2009 was 17.54 $*10^3m^3$, while 1P and 2P developed reserves estimates is 0.43 * 10^3m^3.

13.1 Lower Amaranth A (11_29A)

Eleven wells (3 COOP) have been completed in this pool, with total cumulative oil production of 9.98 * 10^3m^3 at year end 2009. Production from the pool commenced in December 1982 (Fig. 493). The average 2009 calendar day production was 1.8bbl/day and ~95% water cut, indicative that the wells are near end of life. The 1P = 2P developed reserves estimates is 0.43 * 10^3m^3 using the exponential declines of 15.18% per year (Fig. 494).

13.2 Mission Canyon 3b A (11_42A)

Three wells (2 COOP) have been completed in this pool, with total cumulative oil production of 3.12 * 10^3m^3 at year end 2009. Production from the pool commenced in July 1983, and has been erratic with the wells quitting repeatedly (Fig. 495). Production was restored in 2005 after quitting in October 1997. Final production from the pool was in December 2008, hence there are no 1P and 2P developed reserves assigned to the pool, as all the wells have quit production.

14 Regent Field

The Regent field commenced production in January 1955 (Fig. 496), and produced till November 1956. A total of 56 wells have been completed in the field, 33 of which were counted as COOP wells in 2009 and 3 as water injectors. Production resumed in July 1966, and lasted till November 1977, before it was again restored in April 1980. With increasing well count and the introduction of horizontal wells, average yearly production increased from ~42bbl/day (2006) to ~340bbl/day (2007) and ~530bbl/day (2008) before decline set in again. The field's cumulative production at year end 2009 was 117.46 $*10^3m^3$, while 1P and 2P developed reserves estimates are 32.40 $* 10^3m^3$ and 42.62 $* 10^3m^3$ respectively.

14.1 Lodgepole WL A (13_52A)

A total of 17 wells have been drilled / completed in this pool, 10 of which were classified as COOP (7 vertical and 3 horizontal) in 2009. There has been no water flooding in the pool. The pool's total cumulative oil production was 48.49 $* 10^3m^3$ at year end 2009. The vertical wells commenced production in September 1987, and peaked at 160bbl/day a year later (Fig. 497). Current production and 2009 average is ~12bbl/day. The 1P and 2P developed reserves estimates are 2.89 $* 10^3m^3$ and 5.82 $* 10^3m^3$ at exponential declines of 18.62 and 9.42 percent per year respectively (Figures 498 - 499).

The horizontal wells recorded first production in March 2001, and peaked at ~75bbl/day a few months later. Production declined afterwards, and has since been stable at an average of ~12bbl/day till 2008 when further drilling brought production back to ~75bbl/day. Production has been satisfactory since after with a gentle decline to 50bbl/day at end of 2009 leading to cumulative production of 31.50 $*10^3m^3$ (Fig. 500). The 1P and 2P developed reserves estimates are 16.04 $* 10^3m^3$ and 23.05 $* 10^3m^3$ at exponential declines of 51.82 and 38.28 percent per year respectively (Figures 501 - 502).

14.2 Lodgepole WL B (13_53B)

A total of 23 wells have been drilled / completed in this pool, 17 of which were classified as COOP (3 vertical and 14 horizontal) in 2009. The pool's total cumulative oil production was 51.39 $* 10^3m^3$ at year end 2009. The vertical wells have a total cumulative oil production of 3.80 $* 10^3m^3$ at year end 2009 (Fig. 503). The average 2009 calendar day production was <10bbl/day and ~95% water cut, both indicative that the wells are at end of life. Hence, the 1P = 2P developed reserves estimates is 0.61 $* 10^3m^3$ at the exponential declines of 30.03% per year (Fig. 504).

The horizontal wells commenced production in November 2006 and had peak production of ~700bbl/day in March 2008, before declining to 140bbl/day by year end 2009. The total cumulative oil production was 45.96 $* 10^3m^3$ at year end 2009 (Fig. 505). Due to sparse production data, and the inability to impose a decline rate in GEOSCOUT, the 1P was set equal to 2P. Hence, developed reserves estimates is 11.84 $* 10^3m^3$ at exponential declines of 47.37% per year (Fig. 506).

14.3 Lodgepole WL D (13_53D)

Two wells (1 vertical and 1 horizontal - both COOP) have been drilled / completed in this pool, with total cumulative oil production of 2.65 $* 10^3m^3$ at year end 2009. The vertical well commenced production in December 2006. Its cumulative production was 2.0 $* 10^3m^3$, and production had declined to a 2009 average of 4.48bbl/day (Fig. 507). Hence, the 1P = 2P developed reserves estimates is 0.26 $* 10^3m^3$ using the exponential declines of 40.73% per year (Fig. 508). The horizontal well quit production in March 2009; hence no reserves are assigned to it.

14.4 Lodgepole WL E (13_53E)

A total of 3 wells (all COOP) have been drilled / completed in this pool. The pool’s total cumulative oil production was 2.13 * 10^3m^3 at year end 2009.

The two vertical wells commenced production in September 2007 at ~16bbl/day, and had a total cumulative oil production of 0.49 * 10^3m^3 at year end 2009 (Fig. 509). The last two year’s production was an average of ~3bbl/day and a healthy water cut of <60%. The 1P and 2P developed reserves estimates are 0.3 * 10^3m^3 and 0.57 * 10^3m^3 respectively at exponential declines of 26.66% and 15.14% per year respectively (Figures 510 - 511).

The single horizontal well commenced production in March 2008 at ~36bbl/day, and had a cumulative oil production of 1.64 * 10^3m^3 at year end 2009 (Fig. 512). The 2009 production averaged ~9bbl/day and healthy water cut of 80%. Due to the recent low production rates, and the inability to impose a decline rate in GEOSCOUT, the 1P was set equal to 2P. Hence, developed reserves estimates is 0.46 * 10^3m^3 using the exponential declines of 51.07% per year (Fig. 513).

15 Mountainside Field

The Mountainside field commenced production from the Lodgepole WL (14_52A) pool in July 1982 (Fig. 514). A total of 18 wells have been drilled / completed in the field, 10 of which were COOP wells (8 vertical and 2 horizontal) in 2009 and 1 was a water injector. The field's cumulative production at year end 2009 was 127.26 $*10^3m^3$, while 1P and 2P developed reserves estimates are 11.57 $* 10^3m^3$ and 15.41 $* 10^3m^3$.

Production from the vertical wells commenced in July 1982, and peaked at 150bbl/day in July 1985 (Fig. 515). Production remained relatively stable thereafter, until an increase in producing well count from 3 to 8 boosted average yearly production from ~75bbl/day in 1996 to ~270bbl/day in 1997. Current production and 2009 average was ~20bbl/day, hence a cumulative production of 103.48 $*10^3m^3$. The 1P and 2P developed reserves estimates are 9.76 $* 10^3m^3$ and 12.33 $* 10^3m^3$ at exponential declines of 15.78 and 12.73 percent per year respectively (Figures 516 - 517).

The horizontal wells recorded first production in June 1997 at a peak of ~75bbl/day. Production declined afterwards, and has since been stable at an average of ~20bbl/day; leading to a cumulative production of 23.78 $*10^3m^3$ (Fig. 518). The 1P and 2P developed reserves estimates are 1.81 $* 10^3m^3$ and 3.07 $* 10^3m^3$ at exponential declines of 23.75 and 13.43 percent per year respectively (Figures 519 - 520).

16 Birdtail Field

The Birdtail field commenced production in September 1996 (Fig. 521). A total of 29 wells have been completed in the field, 18 of which were COOP wells (17 vertical and 1 horizontal) in 2009 and 4 were water injectors. The field's cumulative production at year end 2009 was 127.26 *10^3m^3, while 1P and 2P developed reserves estimates are 15.18 * 10^3m^3 and 19.51 * 10^3m^3.

16.1 Bakken A - 15_60A (Non-unitized)

Two non-unitized COOP wells were drilled and completed in this pool. The wells commenced production in February 2001, and have a total cumulative oil production of 4.61 * 10^3m^3 at year end 2009. The wells have had erratic production due to repeated downtime in the well performances. The 2009 average daily production was 6.79bbl/day (Fig. 522). The 1P and 2P developed reserves estimates are 1.33 * 10^3m^3 and 1.61 * 10^3m^3 respectively at exponential declines of 14.17% and 11.97% per year respectively (Figures 523 - 524).

16.2 Bakken A - 15_60A (Unit 1)

Six COOP wells were drilled and completed in this pool, in unit no. 1. The wells commenced production in September 1996, and have a total cumulative oil production of 35.28 * 10^3m^3 at year end 2009. The wells recorded peak production (~80bbl/day) in 1997, but the 2009 average daily production was ~24bbl/day (Fig. 525). The 1P and 2P developed reserves estimates are 11.48 * 10^3m^3 and 14.61 * 10^3m^3 respectively at exponential declines of 10.71% and 8.41% per year respectively (Figures 526 -527).

16.3 Bakken C - 15_60C (Non-unitized)

Two non-unitized COOP wells were drilled and completed in this pool. The wells commenced production in January 2001, and have a combined cumulative oil production of 3.47 * 10^3m^3 at year end 2009. One of the wells died in 2002, and the other has produced satisfactorily, with an increase in production thereafter. Its 2009 average daily production was 10bbl/day (Fig. 528). The 1P and 2P developed reserves estimates are 2.37 * 10^3m^3 and 3.28 * 10^3m^3 at the exponential declines of 17.87% and 12.91% respectively per year (Figures 529 -530).

16.4 Bakken C - 15_60C (Unit 2)

Seven COOP wells were drilled and completed in this pool, in unit no. 2. The wells commenced production in September 1996, and have a total cumulative oil production of 35.28 * 10^3m^3 at year end 2009. The wells recorded peak production (~80bbl/day) in 1997, but the 2009 average daily production was ~24bbl/day (Fig. 531). The 1P and 2P developed reserves estimates are 16.82 * 10^3m^3 and 18.04 * 10^3m^3 respectively at exponential declines of 10.71% and 8.41% per year respectively (Figures 532 -533).

The single horizonatl well commenced production in November 2009. Due to insufficient production data, no DCA was done for the well, and hence no reserves are assigned at this time.

17 Other Fields

17.1 Mission Canyon 1 A (99_44A)

A total of 9 wells have been drilled and completed in this pool, 6 of which (4 vertical and 2 horizontal) were COOP and 1 was a water injector. The pool's total cumulative oil production was 64.88 * 10^3m^3 at year end 2009. Water flooding commenced in July 2001.

The group of vertical wells commenced production in November 1981, and died in December 1986. Production was restored in July 1988. Average yearly production increased in 2001 due to increase in producing well count from 3 to 5. Production has since declined and the 2009 average daily production was ~6bbl/day, and a total cumulative oil production of 25 * 10^3m^3 at year end 2009 (Fig. 534). The 1P and 2P developed reserves estimates are 1.08 * 10^3m^3 and 1.66 * 10^3m^3 respectively at exponential declines of 19.14% and 15.76% per year respectively (Figures 535 - 536).

Production from the horizontal wells commenced in November 2000 and peaked at ~380bbl/day. Its cumulative oil production was 38 * 10^3m^3 at year end 2009 (Fig. 537), with average daily production of ~20bbl/day in 2009. The 1P and 2P developed reserves estimates are 2.81 * 10^3m^3 and 7.26 * 10^3m^3 respectively at exponential declines of 30.29% and 10.82% per year respectively (Figures 538 - 539).

17.2 Mission Canyon 1 E (99_44E)

A total of 4 wells (2 vertical and 2 horizontal) have been drilled and completed in this pool. All the wells had died by July 2009 at a total cumulative oil production of 22.49 * 10^3m^3, hence no reserves are assigned to the wells at this time.

17.3 Mission Canyon 1 G (99_44G)

A total of 13 wells have been drilled and completed in this pool, 4 of which (1 vertical and 3 horizontal) were COOP in 2009. The horizontal wells have quit production, hence no reserve. The pool's total cumulative oil production was 34.44 * 10^3m^3 at year end 2009.

The sole vertical COOP well commenced production in February 2002. The well's performance is characterized by high down time. Production has declined and the 2009 average daily production was 2.19bbl/day, and a total cumulative oil production of 2.13 * 10^3m^3 at year end 2009 (Fig. 540). Due to the recent low production rates, and the inability to impose a decline rate in GEOSCOUT, the 1P was set equal to 2P. Hence, developed reserves estimate is 0.18 * 10^3m^3 at the exponential declines of 42.54% per year (Fig. 541).

17.4 Mission Canyon 1 H (99_44H)

A total of 9 wells have been drilled and completed in this pool, 6 of which (all horizontal) were COOP in 2009. The last of the vertical producers quit production in November 2008, hence no reserve assigned for the vertical wells. The pool's total cumulative oil production was 65.75 * 10^3m^3 at year end 2009.

The horizontal COOP wells commenced production in February 1997, and peaked at ~180bbl/day a few months after before declining to ~35bbl/day in 2002. Production peaked again to ~190bbl/day, with increase in producing wells. The cycle was repeated again in 2007. Production had declined to ~85bbl/day and a total cumulative oil production of 56.4 * 10^3m^3 at year end 2009 (Fig. 542). The 1P and 2P developed reserves estimates are 11.26 * 10^3m^3 and 21.30 * 10^3m^3 at the exponential declines of 31.78% and 17.66% respectively per year (Figures 543 - 544).

17.5 Mission Canyon 1 M (99_44M)

A total of 6 wells (all COOP) have been drilled and completed in this pool (3 vertical and 3 horizontal). The pool's total cumulative oil production was 24.27 * 10^3m^3 at year end 2009.

The vertical wells commenced production in October 2004, and have recorded satisfactory performance to date. Production has declined and the 2009 average daily production was ~14bbl/day, and a total cumulative oil production of 8.63 * 10^3m^3 at year end 2009 (Fig. 545). The 1P and 2P developed reserves estimates are 2.02 * 10^3m^3 and 2.69 * 10^3m^3 respectively at exponential declines of 27.03% and 20.36% per year respectively (Figures 546 - 547).

The horizontal wells commenced production in July 2006, and have recorded satisfactory performance to date. Production has declined and the 2009 average daily production was ~45bbl/day, and a total cumulative oil production of 15.65 * 10^3m^3 at year end 2009 (Fig. 548). Recent production has seen a sharp decline from ~42bbl/day to ~25bbl/day. Since the sudden drop in production has not been established with consistency, this thus formed the basis of sensitivity for the 1P and 2P cases, using the same decline trend (13.29% per year). In the 1P case (Fig. 549), it was assumed that the sudden decline was indeed sustained; hence 25bbl/day was used as the forecast start rate. The 2P case DCA (Fig 550) assumed that the sudden decline was not sustained, thus ~42bbl/day was used as the forecast start rate. The 1P and 2P developed reserves estimates are 8.95 * 10^3m^3 and 12.18 * 10^3m^3.

17.6 Mission Canyon 1 O (99_44O)

The sole well (vertical) completed on this pool was brought on stream in December 2005; its performance has been less than satisfactory as its cumulative production at end 2009 was 0.2 * 10^3m^3. Due to scanty production data, the attempted DCA (Fig. 552) resulted in an unrealistic developed reserve estimate of 0.01 * 10^3m^3, at an exponential decline of 50.19% per year. As a result, the 1P and 2P reserves assignment was based on 2 and 3 years production at the current producing rate, resulting in 0.38 * 10^3m^3 and 0.57 * 10^3m^3 respectively.

17.7 Lodgepole Virden C (99_53C)

The sole well (vertical) completed on this pool was brought on stream in October 1998 at ~42bbl/day, and declined to <10bbl/day by July 1998; its performance has been less than satisfactory as its cumulative production at end 2009 was 2.26 * 10^3m^3. The 2009 average daily production was ~2.27bbl/day (Fig. 553). The 1P and 2P developed reserves estimates are 0.34 * 10^3m^3 and 0.72 * 10^3m^3 at exponential declines of 23.97 and 10.92 percent per year respectively (Figures 554 – 555).

17.8 Lodgepole I (99_59I)

The sole well (vertical) completed on this pool was brought on stream in September 2005 at ~260bbl/day. Production declined to <60bbl/day by December 2006, and has been fairly stable since after. The 2009 average daily production was ~32bbl/day (Fig. 556). The 1P and 2P developed reserves estimates are 6.10 * 10^3m^3 and 7.40 * 10^3m^3 at exponential declines of 22.04% and 17.14% per year respectively (Figures 557 – 558).

17.9 Bakken Three Forks N – 99_62N

The group of 5 wells (vertical) completed on this pool was brought on stream in July. The wells have produced on and off due to repeated downtime in the wells' performances. The 2009 calendar day average daily production was ~9bbl/day (Fig. 559). Due to the erratic production history, there are no discernible declines for the DCA. Hence, its estimated 1P =

2P developed reserves is 2.55 * 10^3m^3 (Fig. 560) representing exponential declines of 68.58% per year.

17.10 Bakken Three Forks O – 99_62O

This group of 7 vertical/deviated wells was brought on production in January 2009. Total cumulative oil production was 5.0 *10^3m^3 at year end 2009 (Fig. 561). The wells are yet to commence full decline in performance. The DCA estimates of 1P and 2P DCA were based on the same exponential decline of 26.11% per year. The well's current rate of 188.5bbl/day was applied as the initial forecast rate for the 1P case, while the 2P case assumed a higher forecast rate of 195.6bbl/day (Figures 562 - 563). These yielded 1P and 2P developed reserves of 35.43 * 10^3m^3 and 36.66 * 10^3m^3 respectively.

Operator's reserve estimates were ~194,000 bbl (30.08 * 10^3m^3) and ~314,000 bbl (49.92 * 10^3m^3) respectively. But, the DCA reserve estimates were retained, as they fall within the band of the Operator's estimates.

17.11 Bakken –Three Forks Q (99_62Q)

The sole well (vertical) completed on this pool was brought on stream in September 2009, at ~14bbl/day; its performance has been satisfactory as it is still being ramped up to potential. It had a cumulative production of 0.13 * 10^3m^3 at end 2009. Due to scanty production data, the 1P and 2P reserves assignment were based on 2 and 3 years production at the current rate, resulting in 1.24 * 10^3m^3 and 1.86 * 10^3m^3 respectively.

18 CONCLUSIONS/RECOMMENDATIONS

1) The proved (1P) and Proved + Probable (2P) EUR/DUR for the province are ~313 MMstb (~49.7 * 10^3m^3) and ~330 MMstb (~52.6 * 10^3m^3) of oil respectively, at year end 2009.

2) This represents proved (1P) and Proved + Probable (2P) developed reserves of ~41.64 MMstb (~6.62 * 10^3m^3) and ~59.76 MMstb (~9.5 * 10^3m^3) of oil respectively, at year end 2009.

3) These reserve estimates represent a reserves life index of 4.4 years and 6 years respectively for the 1P and 2P cases respectively.

4) Undeveloped reserves have historically not been reported. To present a complete picture of reserves reporting, it is recommended to always report undeveloped reserves in future reserves review.

5) These estimates do not cover undeveloped (or developed) reserves associated with approved or ongoing activities at end of 2009. These will be considered in the 2010 reserves review.

6) Like in this review, associated gas reserves have historically not been reported. This is because of the uncertainties associated with gas measurements/metering, and the fact that the produced gas for sale are currently either being flared/vented or used to power the oil facilities. Efforts should be made to encourage produced gas gathering for sale, at which time the gas may reported as reserves.

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