CANADA-NEWFOUNDLAND and LABRADOR OFFSHORE PETROLEUM BOARD

# DECISION 2005.02

## RESPECTING

## THE AMENDMENT TO THE TERRA NOVA DEVELOPMENT PLAN

**AUGUST, 2005**

**Disponible en français**

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## 1.0 Summary:

In Decision 97.02 approving the Terra Nova field Benefits and Development Plan, the Canada-Newfoundland and Labrador Offshore Petroleum Board (the Board) noted that the potential of the North Graben area would be assessed early in the field life, and if commercial quantities of oil are confirmed in the area, the Board would require the Proponent to submit a revision to its development plan. Condition 13 of Decision 97.02 stated that "*The Proponent submit for the Board's approval an updated exploitation scheme for the North Graben no later than eighteen months following termination of the first well drilled into this area, as scheduled in the June 1997 Update to the Application*".

On December 17, 2004, Petro-Canada (The Proponent), on behalf of its partners, submitted the document "***Updated Exploitation Scheme for the North Graben Area of the Terra Nova Field***". On January 20, 2005, the Proponent submitted the document "***Updated Exploitation Scheme for the North Graben Area of the Terra Nova Field Addendum***" which contained further information requested by the Board's technical staff. On June 14, 2005, subsequent to the drilling of the F-100 3 well, the Proponent submitted the document "***Updated Exploitation Scheme for the North Graben Area of the Terra Nova Field Addendum, Post F-100 3 (A2)***". The current Application from Petro-Canada proposes development of two fault blocks in the North Graben area utilizing new subsea wells drilled from the Northwest and Northeast drill centers. Each fault block will be exploited with a producer and water injector pair. The Proponent also proposes to allow pressure depletion prior to initiation water injection.

In January 2005, the Proponent was granted approval to drill the first well in the North Graben, F-100 3, with the understanding, that other than for extended production testing purposes, this well would not be allowed to be placed into normal production service until the exploitation scheme has been approved by the Board. In addition to the F-100 3 production well already drilled, an additional injection well will be drilled in the North Graben area in 2005. Pending approval, first oil from the North Graben area is expected in 2005.

The Board's technical staff noted that there is a considerable difference between the geological model carried by the Board and that of the Proponent, particularly for the E sands. However, given the nature of the depositional environment, it is possible to have several reasonable interpretations of distribution of the sandstone reservoirs within the Terra Nova field. The technical staff of the Board accepts that the Proponent's model is a reasonable interpretation. The first well drilled in the North Graben area, F-100 3, indicated poor porosity development within the E sands. The Proponent therefore believes that the E sand trend in the North Graben is farther north than originally identified in the geological model. The Board's technical staff agree with the Proponent's interpretation that this has increased the risk of finding porous E sand across the North Graben area.

The technical staff of the Board reviewed the Proponent's Application and concur with the proposed approach of developing the North Graben area. It is possible that all of the fault blocks in the North Graben area could contain sufficient oil reserves to justify development. In this case, if all of the North Graben fault blocks are developed, as many as 16 development wells may be required to deplete the reserves which would likely require a substantial capital investment to upgrade existing facilities and possibly install a new drill center. The Board considered all factors, including the technical issues, and concluded that the development approach proposed by the Proponent is the best solution.

The Board has therefore approved the following:

**Terra Nova Development Plan Amendment**
**Decision 2005.02**

The Board approves the Proponent's proposed North Graben exploitation scheme to develop the NGSE and NGCE fault blocks, subject to Condition 2005.02.01 and the conditions contained in its Decision Reports 97.02 and 2002.02. The outstanding conditions are summarized in Appendix C.

**Condition 2005.02.01**
The Proponent provide a delineation plan, acceptable to the Board, for the North Graben area by September 30, 2008.

# 2.0 Present Application

## 2.1 Background

On August 5, 1996, Petro-Canada (the Proponent) on behalf of the Terra Nova partners submitted a Development Application for the Terra Nova Field. In the original Development Plan for the Terra Nova field, the Proponent stated that it believed the quantity of oil-in-place in the North Graben was insufficient to justify its development, and therefore the North Graben area was not included as part of the original development. The Proponent stated that it planned to drill a pilot hole in the North Graben area early in the field life prior to production.

The C-NOPB approved the Terra Nova Development Plan in Decision 97.02 with several conditions. In its decision, the Board noted that the potential of the North Graben would be assessed early in the field life, and if commercial quantities of oil are confirmed in the area, the Board would require the Proponent to submit a revision to its development plan. Decision 97.02 Condition 13 stated that "The Proponent submit for the Board's approval an updated exploitation scheme for the North Graben no later than eighteen months following termination of the first well drilled into this area, as scheduled in the June 1997 Update to the Application".

Prior to initiating development drilling in the field, the Proponent re-interpreted its seismic data and identified faults that could potentially isolate a production well from a gas injection well to be drilled in the southern area of the C09 fault block. Therefore, the Proponent selected a drilling location for a development well further to the south. Subsequent development wells drilled in the vicinity of the North Graben area confirmed the existence of oil bearing reservoir sands that may extend into the North Graben area. For this reason, rather than drilling a throw-away pilot hole, the Proponent elected to drill a development well, F-100 3, to evaluate the North Graben area and also use the well for production if oil was encountered. The Proponent has since drilled the F-100 3 well in the North Graben area and confirmed the existence of oil.

On December 17, 2004, Petro-Canada, on behalf of its partners, submitted the document "***Updated Exploitation Scheme for the North Graben Area of the Terra Nova Field***". On January 20, 2005 the Proponent submitted the document "***Updated Exploitation Scheme for the North Graben Area of the Terra Nova Field Addendum***" which contained further information requested by the Board's technical staff. On June 14, 2005, subsequent to the drilling of the F-100 3 well, the Proponent submitted the document "***Updated Exploitation Scheme for the North Graben Area of the Terra Nova Field Addendum, Post F-100 3 (A2)***". These documents include Petro-Canada's latest interpretation of the North Graben area of the field and outline the Proponent's current development plans for this area. The current Application from Petro-Canada proposes development of two fault blocks in the North Graben area utilizing new subsea wells located in the Northwest and Northeast drill centers. In addition to the F-100 3 production well, a water injection well will be drilled in the North Graben area in 2005. First oil from the North Graben area is expected in 2005.

The following section of the report presents an overview of the Proponent's Application.

## 2.2 Proponent's December 2004 Application

### 2.2.1 Geological Model

The current geologic model being used by the Proponent is their 2003A model. This model is based on 46 wellbores, 37 of which have penetrated the Jeanne d'Arc sands in the Terra Nova field. All wells up to and including the F-100 1 well have been included. The model is an alluvial / fluvial to marginal marine deposition within a braidplain / braid delta setting. The Proponent's Jeanne d'Arc stratigraphy identifies five major and three minor oil bearing sands (Figure 1). An isochore of each of the oil bearing intervals for the Terra Nova field is shown in Appendix A.

Wells that have been drilled since the F-100 1 well (L-98 10, L-98 9, F-88 2, F-100 2 and F-100 3) have not substantially affected the correlations or interpretations used. However, the F-100 3 well has changed the Proponent's interpretation of the E sand within the North Graben area. The F-100 3 well encountered a thin E sand with no porosity development which has led the Proponent to the interpretation that the E sand trend across the North Graben is farther north than identified in the previous geological model.

***Figure 1: Jeanne d'Arc Formation Stratigraphy (Source: After Petro-Canada 2004)***

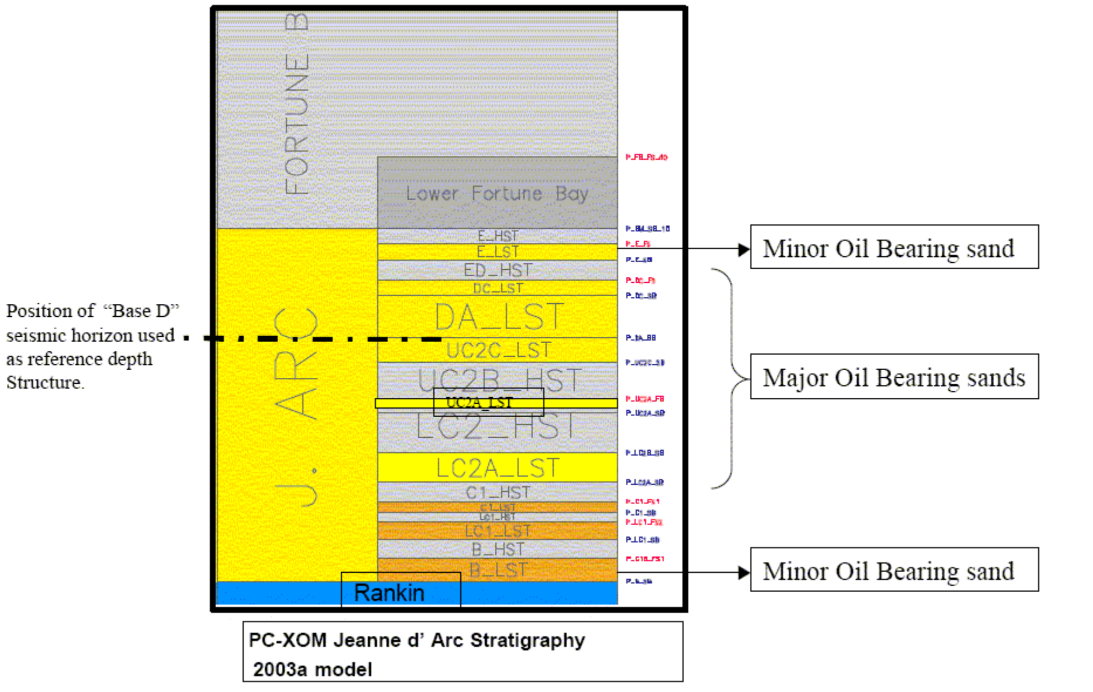



Figure 3.2: Schematic stratigraphic column used to subdivide Jeanne d'Arc reservoir, Terra Nova Field

## 2.2.2 Oil-in-Place and Reserve Estimates

In its application, the Proponent presented volumetric assessments of original oil-in-place for the North Graben area of the field. According to the Proponent, the structurally highest blocks in the North Graben are the NGSE and NGCE blocks (Figure 2). These two fault blocks are the only blocks proposed for development in the North Graben area at this time. Table 1 presents the Proponent's deterministic original oil-in-place volumes for the North Graben area, prior to the drilling of the F-100 3 well. The NGSE and NGCE blocks, currently proposed for development, are estimated to contain 2.27 $10^6$ $Sm^3$ (14 million barrels) and 3.43 $10^6$ $Sm^3$ (22 million barrels) original oil-in-place, respectively. Prior to the drilling of the F-100 3 well, the Proponent estimated that 88% (18.38 $10^6$ Sm3, 116 million barrels) of the total oil-in-place for the North Graben area was contained within the E sand.

An oil-water contact of -3,560 mSS was assumed for the North Graben area, based on the oil down to encountered in the F-100 1 well. The F-100 3 well encountered an actual oil-water contact of -3,568 mSS. The F-100 3 well confirmed the predicted reservoir trends for the LC2A, UC2A and DA sands, however the E sand development was thinner than prognosed without any porosity development. Updated volumetrics based on the results of the F-100 3 well are not yet finalized, however the Proponent estimates that the only significant change will be within the E sand in the NGSE fault block, where there may potentially be a loss of 1.16 $10^6$ $Sm^3$ (7.3 million barrels) of oil-in-place.

A probabilistic estimate of the original oil-in-place volumes was also undertaken by the Proponent. The purpose of the probabilistic approach was to determine the range of outcomes for the original oil-in-place that could be expected in the North Graben area, and to evaluate the risk associated with encountering this range of oil-in-place. Each of the inputs included in the probabilistic approach were modeled as distributions. The resulting stock tank original oil-in-place (STOOIP) distributions are shown in Table 2. The P50 STOOIP volumes for the NGSE and NGCE blocks in the North Graben are 2.45 $10^6$ $Sm^3$ (15.4 million barrels) and 2.61 $10^6$ $Sm^3$ (16.4 million barrels), respectively. The P50 STOOIP for the total North Graben area is 12.52 x $10^6$ $Sm^3$ (78.7 million barrels).

***Figure 2: North Graben Development Scheme***
***(Source: After Petro-Canada 2004)***

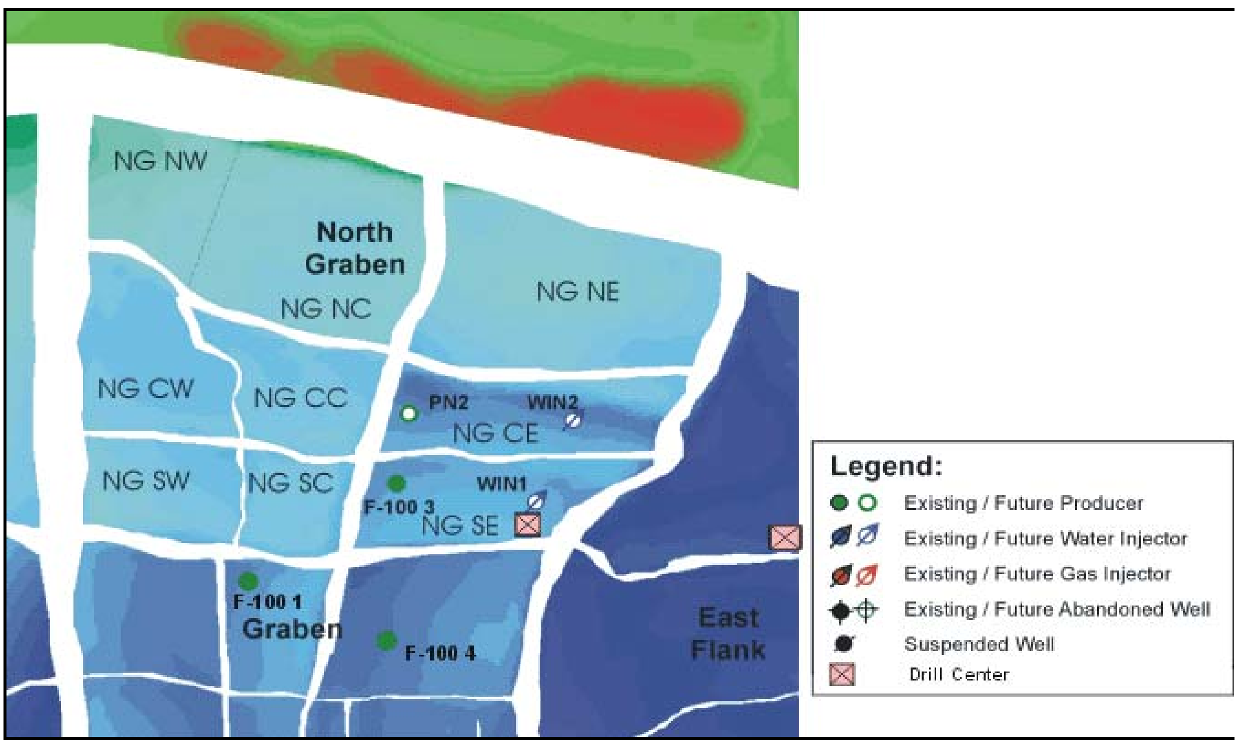


***Table 1: North Graben Deterministic Volumes ($10^6$ $Sm^3$)***
***(Source: After Petro-Canada 2004)***

| Fault Block | E Sand | D Sand | C Sand | Total |
|---|---|---|---|---|
| NGSE | 1.16 | 0.10 | 1.01 | 2.27 |
| NGSC | 0.97 | 0.01 | 0.00 | 0.98 |
| NGSW | 1.69 | 0.00 | 0.05 | 1.74 |
| NGCW | 2.15 | 0.00 | 0.00 | 2.15 |
| NGCC | 2.52 | 0.00 | 0.00 | 2.52 |
| NGCE | 2.17 | 0.00 | 1.26 | 3.43 |
| NGNE | 4.93 | 0.00 | 0.07 | 5.00 |
| NGNC | 0.00 | 0.00 | 0.00 | 0.00 |
| NGNW | 2.75 | 0.00 | 0.00 | 2.75 |
| **Total:** | **18.34** ***(115.4 million bbls)*** | **0.11** ***(0.7 million bbls)*** | **2.39** ***(15.0 million bbls)*** | **20.84** ***(131.08 million bbls)*** |

The Chance of Success (COS) for the North Graben opportunities was also examined, since there is still a high degree of uncertainty remaining in the area. To determine the COS, all of the contributing factors including source, seal, reservoir and structure were evaluated by the Proponent. The main risk in the North Graben area of the field is the risk of low quality sand and cementation. The estimated COS for encountering the reserves for the NGSE and NGCE blocks was estimated to be 63%. Various components were also modeled to determine a distribution for the recovery factors. The resulting recovery factor distribution was used for all formations. The P50, P90 and P10 recovery factors were 0.35, 0.25 and 0.45 respectively. The final results from the probabilistic modeling of reserves were combined with the chance of success to determine the risked reserves for the North Graben area. A summary of the Proponent's risked reserves for the NGSE and NGCE fault blocks is shown in Table 3. According to the Proponent, the NGSE and NGCE fault blocks each carry risked reserves of 0.6 $10^6$ $Sm^3$ (4.0 million barrels).

*Table 2: North Graben Probabilistic STOOIP Results (Source: After Petro-Canada 2004)*

| | STOOIP $10^6$ $m^3$ | | |
|---|---|---|---|
| | **NGSE** | **NGCE** | **NG Total** |
| **Minimum** | 0.24 | 0.34 | 1.27 |
| **Maximum** | 12.08 | 23.71 | 99.43 |
| **Mean** | 2.76 | 2.98 | 15.04 |
| **Standard Deviation** | 1.51 | 1.72 | 10.11 |
| **Variance** | 2.28 | 2.95 | 102.18 |
| **Skewness** | 1.20 | 1.57 | 1.71 |
| **Kurtosis** | 5.06 | 9.31 | 7.88 |
| **Number of Errors** | 0.00 | 0.00 | 0.00 |
| **Mode** | 1.99 | 2.37 | 9.14 |
| 95% | 0.91 | 0.96 | 3.87 |
| 90% | **1.13** | **1.18** | **4.94** |
| 85% | 1.31 | 1.37 | 5.96 |
| 80% | 1.47 | 1.55 | 6.96 |
| 75% | 1.64 | 1.71 | 7.83 |
| 70% | 1.79 | 1.88 | 8.73 |
| 65% | 1.95 | 2.06 | 9.73 |
| 60% | 2.11 | 2.25 | 10.59 |
| 55% | 2.27 | 2.41 | 11.49 |
| 50% | **2.45** | **2.61** | **12.52** |
| 45% | 2.62 | 2.82 | 13.68 |
| 40% | 2.83 | 3.03 | 14.88 |
| 35% | 3.03 | 3.26 | 16.25 |
| 30% | 3.29 | 3.54 | 17.72 |
| 25% | 3.56 | 3.86 | 19.70 |
| 20% | 3.90 | 4.22 | 21.59 |
| 15% | 4.30 | 4.64 | 24.31 |
| 10% | **4.84** | **5.24** | **28.19** |
| 5% | 5.63 | 6.27 | 34.48 |
| **Coeff of Variation** | 55% | 58% | 67% |

*Table 3: North Graben Risked Reserves (Source: After Petro-Canada 2004)*

| Opportunity | Det. ML MMbbl | P90 MMbbl | P50 MMbbl | P10 MMbbl | COS % | Risked Reserves MMbbl |
|---|---|---|---|---|---|---|
| NGSE | 8 | 2 | 5 | 11 | 63 | 4 |
| NGCE | 8 | 2 | 6 | 12 | 63 | 4 |

### 2.2.3 Development Strategy

In the current application, the Proponent is proposing to develop the North Graben NGSE and NGCE fault blocks, using water injection for pressure support and existing facilities at the Northwest and Northeast drill centers. A producer-injector pair will be required in each fault block. To date, the Proponent has drilled one well, F-100 3, a production well in the NGSE fault block (Figure 2).

The base case drilling schedule for the Terra Nova field, including the North Graben area, is presented in Figure 3. The Proponent proposes to induce pressure depletion prior to the initiation of water injection. The NGSE and NGCE blocks will be depleted to 25,000-30,000 kPa (above the saturation pressure) which will allow the communication with other adjacent blocks to be assessed. The supporting water injection well, WIN1, in the NGSE fault block is proposed to be drilled and completed in Q3 2005. First oil from the North Graben is projected for Q3 2005.

***Figure 3: Base Case Drilling Schedule***
***(Source: After Petro-Canada 2004)***

**Terra Nova Base Well Schedule**
**Full Field Development**
**Graben + East Flank + North Graben + Far East**

| Well # | Well Name | Host/ Slot | RMT Common Name | DC | Time (Est) | Schedule: Start Drilling | Schedule: Finish Drilling |
|---|---|---|---|---|---|---|---|
| 20 | L-98 11Y | C4-P | PE7 | SW | 93 | 8-Aug-04 | 9-Nov-04 |
| | compl WIE2 | | | NE | 21 | 9-Nov-04 | 30-Nov-04 |
| 21 | | E4-W | WIE6 | SE | 47 | 30-Nov-04 | 16-Jan-05 |
| 22 | | A2-P | PN1 | NW | 33 | 16-Jan-05 | 18-Feb-05 |
| | Rig Inspection/Upgrade | | | | 35 | 18-Feb-05 | 25-Mar-05 |
| | compl PN1 | | | NW | 29 | 25-Mar-05 | 23-Apr-05 |
| 24 | | F2-P | PF1 | NE | 82 | 23-Apr-05 | 14-Jul-05 |
| 25 | | F1-W | WIN1 | NE | 58 | 14-Jul-05 | 10-Sep-05 |
| 26 | | E3-W | WIF1 | SE | 73 | 10-Sep-05 | 22-Nov-05 |
| | | F3-W | WIE8 | NE | 49 | 22-Nov-05 | 10-Jan-06 |
| 27 | | D4-GST | GIG1 | SW | 87 | 10-Jan-06 | 7-Apr-06 |
| | 2006 Interventions | | | | 33 | 7-Apr-06 | 10-May-06 |
| 28 | | G1-P | PG7 | NE | 62 | 10-May-06 | 11-Jul-06 |
| 29 | | A1-P | PG6 | NW | 80 | 11-Jul-06 | 29-Sep-06 |
| 30 | | C1-GST | GIG4 | SW | 97 | 29-Sep-06 | 4-Jan-07 |
| 31 | | B2-PST | PE8 | SW | 126 | 4-Jan-07 | 10-May-07 |
| 32 | | G3-PST | PE2 | NE | 68 | | 1-Jul-11 |
| 33 | | C4-PST | PE9 | SW | 101 | | 10-Oct-11 |
| 34 | | A2-PST | PN2 | NW | 101 | | 1-Jul-12 |
| 35 | | F1-WST | WIN2 | NE | 79 | | 18-Sep-12 |
| 36 | | F2-PST | PF3 | NE | 103 | | 1-Jul-14 |
| 37 | | E2-WST | WIF2 | SE | 82 | | 21-Sep-14 |

**Note:** The timing of sidetrack wells (including PN2 and WIN2) is dependent on slot availablity and/or expansion of existing Drill Centers. The results from North Graben and Far East production performance, ongoing resource assessments (PSDM/RCA/etc) may result in subsea expansion of the existing Drill Centers, resulting in an acceleration of the sidetrack wells.

The production and injection wells required for the NGCE fault block are proposed to be drilled as sidetracks of the initial production and injection wells. It is assumed that these sidetracks will be drilled in 2012 after the first producer-injector pair is abandoned. Alternatively, the second North Graben producer and injector may be sidetracked from other well slots as they become available.

### 2.2.4 Delineation Strategy

The Proponent has developed a North Graben delineation strategy to determine how North Graben opportunities can be progressed through delineation and possible development. The Proponent’s strategy involves reducing the uncertainty and improving the viability of North Graben opportunities. According to the Proponent, the results from the first well drilled in the area, F-100 3, will help to reduce the uncertainty surrounding sand distribution and oil-in-place and will be used to direct further development. Also, long-term production from a successful first well will test reservoir compartmentalization issues, reduce uncertainty around recovery and help in selecting the location of the supporting water injection well. The Proponent believes that North Graben development should be approached in a step-wise manner, since the remaining North Graben opportunities carry considerable risk.

The F-100 3 well, drilled in North Graben NGSE fault block, tested several geological uncertainties including reservoir quality, the presence of the E sand and the oil-water contact. The Proponent states that for North Graben development to extend beyond the two proposed fault blocks, two factors would have to be positive in the first two wells: good sand development and hydrocarbon pay. Also, an upward shift in the structure or a downward shift in the oil-water contact would be necessary in order to place more oil-in-place in the other North Graben fault blocks.

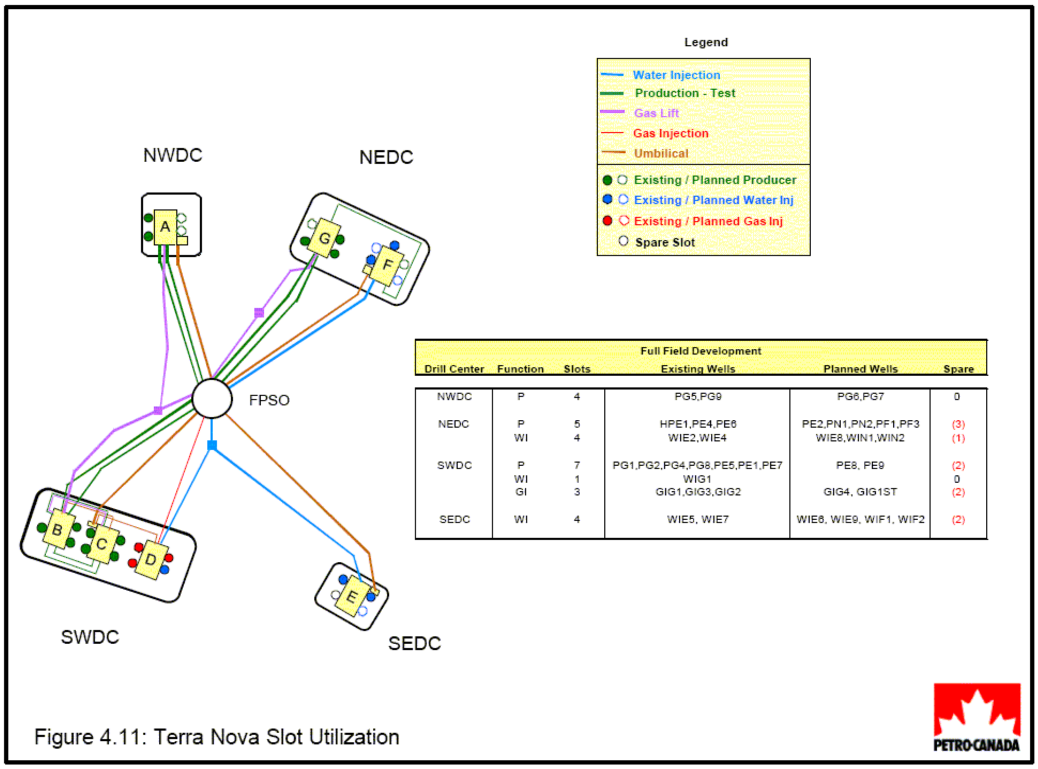
In terms of improving viability of North Graben opportunities, the Proponent installed an upgraded top drive on the Terra Nova drilling unit in Q1 2005. This will enable all remaining undeveloped North Graben blocks to be drilled from the Northwest and Northeast drill centers. Both drill centers contain sufficient space for installation of new well slots via satellite systems.

### 2.2.5 Drill Centre Expansion Capabilities

Based on the current drilling schedule, the current slot utilization at the Terra Nova field suggests that an additional 3 production slots and 1 water injection slot would be required in the Northeast drill centre and an additional 2 water injection slots would be required in the Southeast drill centre (Figure 4). Since these additional slots are not available, this would represent the number of sidetracks that would be required. The Proponent states, that as the number of required sidetracks increase, it may become more attractive to drill these wells earlier through the use of additional subsea infrastructure. This can be accomplished by either expanding the existing drill centers or by adding new drill centers. Since the submission of the Proponent's Application, the two remaining production slots shown in Figure 4 in the Northwest drill center have also been used for the F-100 3 and F-100 4 wells, and there are currently no drill slots remaining in the Northwest drill center.

The Proponent has conducted a preliminary investigation of expansion capability of the current drill centers. This investigation suggests that up to 8 additional producers, 6 water injectors and 1 gas injector could be added to the existing glory holes. In the Northeast drill center, there may be sufficient space to add another production template, which could accommodate 4 additional production wells. The Northeast drill center could also accommodate 3 satellite water injection wells, as is shown in Figure 5. If additional wells are required beyond the expansion capabilities of the current drill centers, the Proponent has indicated that a new drill center would also be considered. The FPSO has the capacity to handle a new drill center that would be tied directly back to the FPSO or tied back through an existing drill center. The Proponent believes that through the use of sidetracks, drill center expansion and the use of new drill centers, the upside potential for the North Graben area of the field can be accommodated.

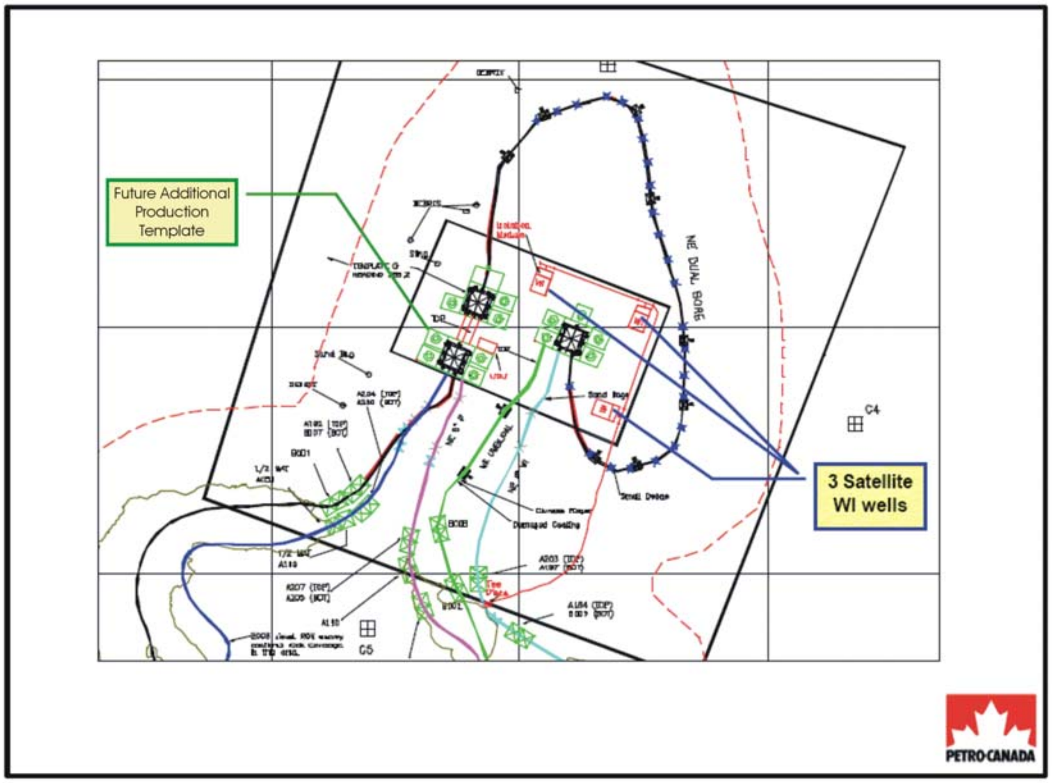
***Figure 4: Terra Nova Field Slot Utilization (Source: After Petro-Canada 2004)***




| Full Field Development | | | | | |
|---|---|---|---|---|---|
| Drill Center | Function | Slots | Existing Wells | Planned Wells | Spare |
| NWDC | P | 4 | PG5,PG9 | PG6,PG7 | 0 |
| NEDC | P | 5 | HPE1,PE4,PE6 | PE2,PN1,PN2,PF1,PF3 | (3) |
| | WI | 4 | WIE2,WIE4 | WIE8,WIN1,WIN2 | (1) |
| SWDC | P | 7 | PG1,PG2,PG4,PG8,PE5,PE1,PE7 | PE8, PE9 | (2) |
| | WI | 1 | WIG1 | | 0 |
| | GI | 3 | GIG1,GIG3,GIG2 | GIG4, GIG1ST | (2) |
| SEDC | WI | 4 | WIE5, WIE7 | WIE6, WIE9, WIF1, WIF2 | (2) |

Figure 4.11: Terra Nova Slot Utilization

***Figure 5: Potential Northeast Drill Center Expansion (Source: After Petro-Canada 2005)***



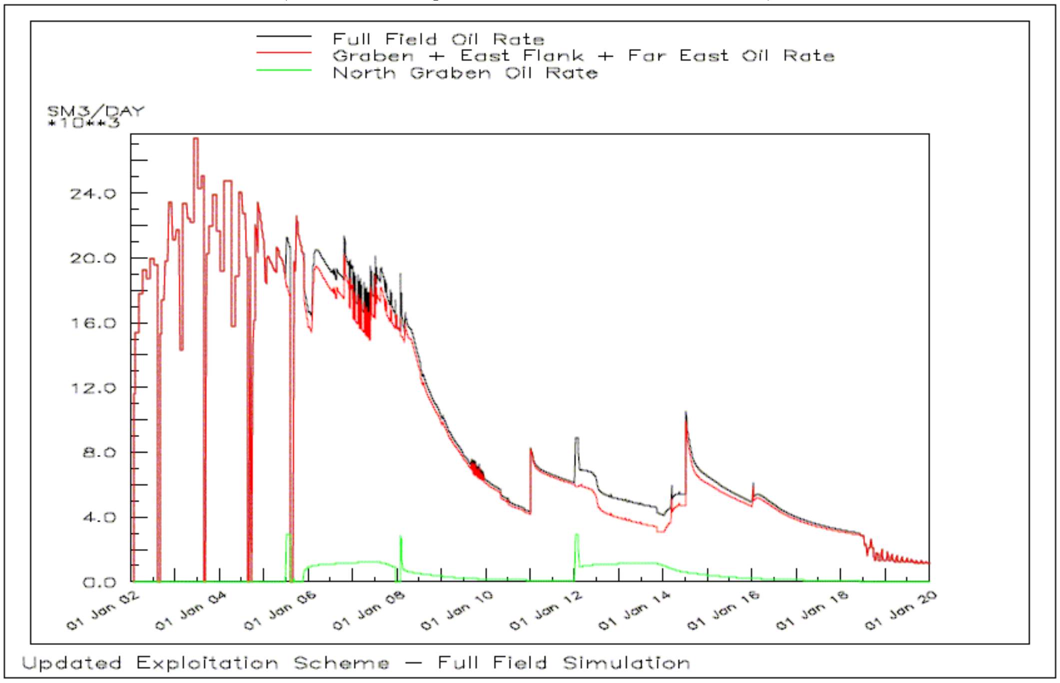

## 2.2.6 Reservoir Simulation Model and Production Forecast

The Proponent has constructed a full field reservoir simulation model to continue optimization of the Graben and East Flank areas and also to evaluate the North Graben development strategy. The simulation model is based on the 2003A geological model which was updated with the results of all wells up to and including F-100 1. The simulation model has been history matched up to the end of June, 2004.

The model consists of 150 by 100 grids with 57 layers for a total of 940,500 cells. Three PVT regions have been defined including the Graben / North Graben, East Flank and Far East. Water saturation was assigned in the grid based on the results of capillary pressure tests. An average water saturation of 12% is used in the model above the oil-water contact. An oil down to -3,560 mSS from the F-100 1 well was adopted as the most likely oil-water contact for the Graben and North Graben areas. The F-100 3 well encountered an oil-water contact of -3,568 mSS. The oil-water and gas-oil relative permeability curves have remained unchanged since the "Reservoir Basis for the Terra Nova Development" was submitted to the Board in March 1998.

The full field production forecast, including the contribution from the North Graben area, is shown in Figure 7. Each of the North Graben producers is capable of producing at rates of 1,000 to 3,000 $Sm^3/d$. When the North Graben first begins production, an immediate increase in the production is observed in 2005. A second jump in production is seen in 2012 after the second production well in the North Graben begins production.

***Figure 6: Terra Nova Field Production Forecast (Source: After Petro-Canada 2004)***



## 2.3 Board's Review

The Board's technical staff have reviewed the documents submitted in support of the application including "***Updated Exploitation Scheme for the North Graben Area of the Terra Nova Field***" submitted in December, 2004, "***Updated Exploitation Scheme for the North Graben Area of the Terra Nova Field Addendum***" submitted on January 20, 2005 and "***Updated Exploitation Scheme for the North Graben Area of the Terra Nova Field Addendum, Post F-100 3 (A2)"*** submitted June 14, 2005. Staff have also reviewed the Proponent's reservoir simulation model and geological information and conducted a review of reservoir, geological and production data acquired to date. As of May 31, 2005, twenty-six development wells have been drilled and 23.0 million $m^3$ (144.7 million barrels) of oil have been produced from the Terra Nova field. This has provided a substantial quantity of new information to assess reservoir and facility performance and construct geological and reservoir simulation models. The Board acknowledges that the Proponent has conducted a comprehensive assessment of the information available in support of its application.

### 2.3.1 Geological Model Review

The Board's technical staff has conducted a comprehensive review of geological information and constructed a geologic model of the Jeanne d'Arc formation sandstone reservoirs. The staff concur with the Proponent that the depositional environment is an alluvial / fluvial to marginal marine deposition within a braidplain / braid delta setting. Isopachs of the main intervals mapped by the Board's staff are provided in Appendix B. It is noted that there is a considerable difference between the geological model carried by the Board and that of the Proponent, particularly for the E sands. However, given the nature of the depositional environment, it is possible to have several reasonable interpretations of distribution of the sandstone reservoirs within the Terra Nova field.

The results of the F-100 3 well indicated poor porosity development within the E sands and therefore the Proponent's current interpretation is that the E sand trend in the North Graben is farther north than originally identified in the geological model. The Board's technical staff has not mapped E Sands in the North Graben area, however, they recognize the possibility for E Sands to be present in the North Graben. It is the view of the Board's technical staff that if reservoir quality sands are present to the north, they will likely be structurally lower than those encountered in the F-100 3 well and potentially at or below the mapped oil-water contact of -3,568 mSS. However, the technical staff of the Board accepts that the Proponent's model is a reasonable interpretation

Both the Proponent and the Board's technical staff have analyzed the open hole logs from the F-100 3 well. Petrophysical analysis by the Board's technical staff indicates that the F-100 3 well had an oil down to of -3,567 mSS before encountering approximately two meters of non-porous sandstone above a definitive water zone at -3,569 mSS. This interpretation is aligned with the Proponent's submission that an oil-water contact exists at -3,568 mSS. Analysis of wireline pressure data by Board technical staff indicates a slight pressure depletion in the F-100 3 well, possibly caused by pressure communication with other producers in the nearby Graben area.

The first well drilled in the NGSE fault block, F-100 3, has reduced some of the uncertainty surrounding the oil-water contact in the North Graben area and has provided important information regarding the potential of E Sands in the area.

### 2.3.2 Reservoir Simulation Model Review

The Board's technical staff reviewed the data and assumptions used to construct the reservoir simulation model. The Board's staff notes that the two production wells in the North Graben are only perforated within the D and C sands in the simulation model while the F-100 3 well encountered no hydrocarbon bearing reservoir in the D sands. The reservoir simulation model needs to be updated to reflect the information from the F-100 3 well. However, the staff believe that considering all the factors, it is not necessary to update the simulation model prior to completing a review of this Application.

### 2.3.3 Oil-in-Place and Reserve Estimates

The Board's technical staff has conducted an assessment of the oil-in-place for the North Graben area of the field based on the Board's geological model. A comparison of the Proponent's and the Board's volumetric oil-in-place estimates by sand is shown in Table 4.

The largest difference in the Proponent's and the Board's volumetric oil-in-place estimates is within the E Sand. While the Proponent originally attributed 88 % of the volumetric oil-in-place estimates to the E Sands in the North Graben, the Proponent has stated that updated volumetric analysis, which will include the results of the F-100 3 well, will likely result in a loss of 1.16 $10^6$ $Sm^3$ within the E sand in the NGSE fault block. The Board's technical staff believe that the oil-in-place in the North Graben area is mainly in the D and C sands.

***Table 4: Comparison of C-NLOPB's and Proponent's Volumetric Original Oil-in-Place Estimates(million $Sm^3$)***

| Fault Block | E Sand | | D Sand | | C Sand | | Total | |
|---|---|---|---|---|---|---|---|---|
| | C-NOPB | Proponent | C-NOPB | Proponent | C-NOPB | Proponent | C-NOPB | Proponent |
| NGSE | 0.00 | 1.16 | 0.44 | 0.10 | 1.58 | 1.01 | 2.02 | 2.27 |
| NGSC | 0.00 | 0.97 | 0.34 | 0.01 | 0.00 | 0.00 | 0.34 | 0.98 |
| NGSW | 0.00 | 1.69 | 0.77 | 0.00 | 0.10 | 0.05 | 0.87 | 1.74 |
| NGCW | 0.00 | 2.15 | 1.72 | 0.00 | 0.58 | 0.00 | 2.30 | 2.15 |
| NGCC | 0.00 | 2.52 | 0.17 | 0.00 | 0.00 | 0.00 | 0.17 | 2.52 |
| NGCE | 0.00 | 2.17 | 0.22 | 0.00 | 1.69 | 1.26 | 1.91 | 3.43 |
| NGNE | 0.00 | 4.93 | 0.10 | 0.00 | 0.42 | 0.07 | 0.53 | 5.00 |
| NGNC & NGNW | 0.00 | 2.75 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 2.75 |
| **Total ($10^6$ $Sm^3$)** | **0.00** | **18.34** | **3.77** | **0.11** | **4.38** | **2.39** | **8.15** | **20.84** |
| **Total (million barrels)** | **0.00** | **115.35** | **23.69** | **0.69** | **27.56** | **15.03** | **51.25** | **131.08** |

The technical staff of the Board conducted a reserve assessment of the North Graben area in March 2004. All geological and production information available up to December 31, 2003 was considered in the assessment. Based on this assessment, the staff assigned no proven or probable reserves to the North Graben, since no well was drilled in this area, however the Board assigned possible reserves as shown in Table 5.

***Table 5: C-NLOPB's North Graben Reserve Estimates***

| Fault Block | Proven ($10^6$ $Sm^3$) | Proven plus Probable ($10^6$ $Sm^3$) | Proven plus Probable plus Possible ($10^6$ $Sm^3$) |
|---|---|---|---|
| NGSE | 0 | 0 | 0.87 |
| NGSC | 0 | 0 | 0 |
| NGSW | 0 | 0 | 0 |
| NGCW | 0 | 0 | 0 |
| NGCC | 0 | 0 | 0 |
| NGCE | 0 | 0 | 0.88 |
| NGNE | 0 | 0 | 0 |
| NGNC & NGNW | 0 | 0 | 0 |
| **Total ( $10^6$ $Sm^3$)** | **0** | **0** | **1.75** |
| **Total (million barrels)** | **0** | **0** | **11.00** |

Since this reserve estimate was conducted, the Terra Nova F-100 1 , F-100 2 and F-100 3 wells were drilled. It would be appropriate based on the information gained from these wells, to assign total proven plus probable oil reserves of 1 million $Sm^3$ (6.3 million barrels) to the NGSE and NGCE fault blocks. In comparison, the Proponent has assigned risked reserves of 1.2 million $Sm^3$ (8 million barrels) to these blocks.

### 2.3.4 Delineation Strategy

The Proponent notes that due to the overall uncertainty in the North Graben, it is important to approach a development in this area as a staged development. Uncertainty still exists around the geological model which indicates that the Jeanne d'Arc sands become progressively more distal to the north. Also, the southern edge of the E sand trend across the North Graben is seismically unresolvable and difficult to predict. The wells drilled to date in the North Graben and Graben areas support this interpretation.

The Proponent has developed a delineation strategy for the North Graben area to address how identified opportunities can be progressed to the point of delineation and possible development. The strategy is comprised of reducing the uncertainty and improving the viability of the North Graben opportunities. The Proponent notes that the two key risk factors are the sand distribution and oil-in-place.

The Proponent has not committed to any delineation drilling in the North Graben area. The Board will require the Proponent to reflect on their delineation plans following an assessment of information acquired from the wells drilled in the NGSE fault block.

### 2.3.5 Development Strategy

The technical staff of the Board concur with the Proponent's proposal to develop the North Graben NGSE and NGCE fault blocks, using water injection for pressure support and existing facilities at the Northwest and Northeast drill centers. Also, the Board's technical staff concur with the Proponent's proposal to allow pressure depletion prior to implementing water injection.

The Proponent was granted approval to drill the F-100 3 well in the NGSE fault block with the understanding, that other than for extended production testing purposes, this well would not be allowed to be placed into normal production service until the exploitation scheme has been approved by the Board. The F-100 3 well has determined the oil-water contact in the North Graben and also reduced the structural and geologic uncertainty in the area which was essential information required to assess the development potential of the North Graben.

The technical staff of the Board acknowledge the significant geological and structural uncertainty in respect of the North Graben area. It is possible that oil reserves could be confined to the NGSE and NGCE fault blocks or, alternatively, all the fault blocks in the North Graben area could contain sufficient oil reserves to justify development. In the latter case, if all of the North Graben fault blocks are developed, up to 16 development wells may be required to deplete the reserves which would likely require a substantial capital investment to upgrade existing facilities and possibly install a new drill center.

Considering the uncertainty, the Board's technical staff concur with the development strategy proposed by the Proponent for the North Graben area. Should the results of drilling indicate any significant change in the premises upon which the present Development Plan is approved, the Proponent will be required to submit for the Board's approval an amended plan that takes this new information into account.

The development wells required to exploit the NGSE and NGCE fault blocks will be drilled through the existing Northeast and Northwest drill centers. Given the proposed drilling schedule, all of the drilling slots within the four existing drill centers will have been used by the end of 2006 and the field will become slot constrained. After that point, future wells will be drilled as sidetracks as other wells are abandoned and slots become available. Without expansion of existing centers or the addition of new centers, the Proponent has no flexibility to deal, in a timely manner, with opportunities or problems that may arise in the field. This must be considered in the context that the FPSO and subsea facilities have a design life beyond which substantial capital investments to extend the service life of the facilities may be required. If reserves are not developed within the current service life of the facilities, it is possible they may not be developed. The Board's technical staff will pursue these factors with the Proponent, which should be drawn to a conclusion in advance of the delineation plan required by Condition 2005.01.02.

The Board has therefore approved the following:

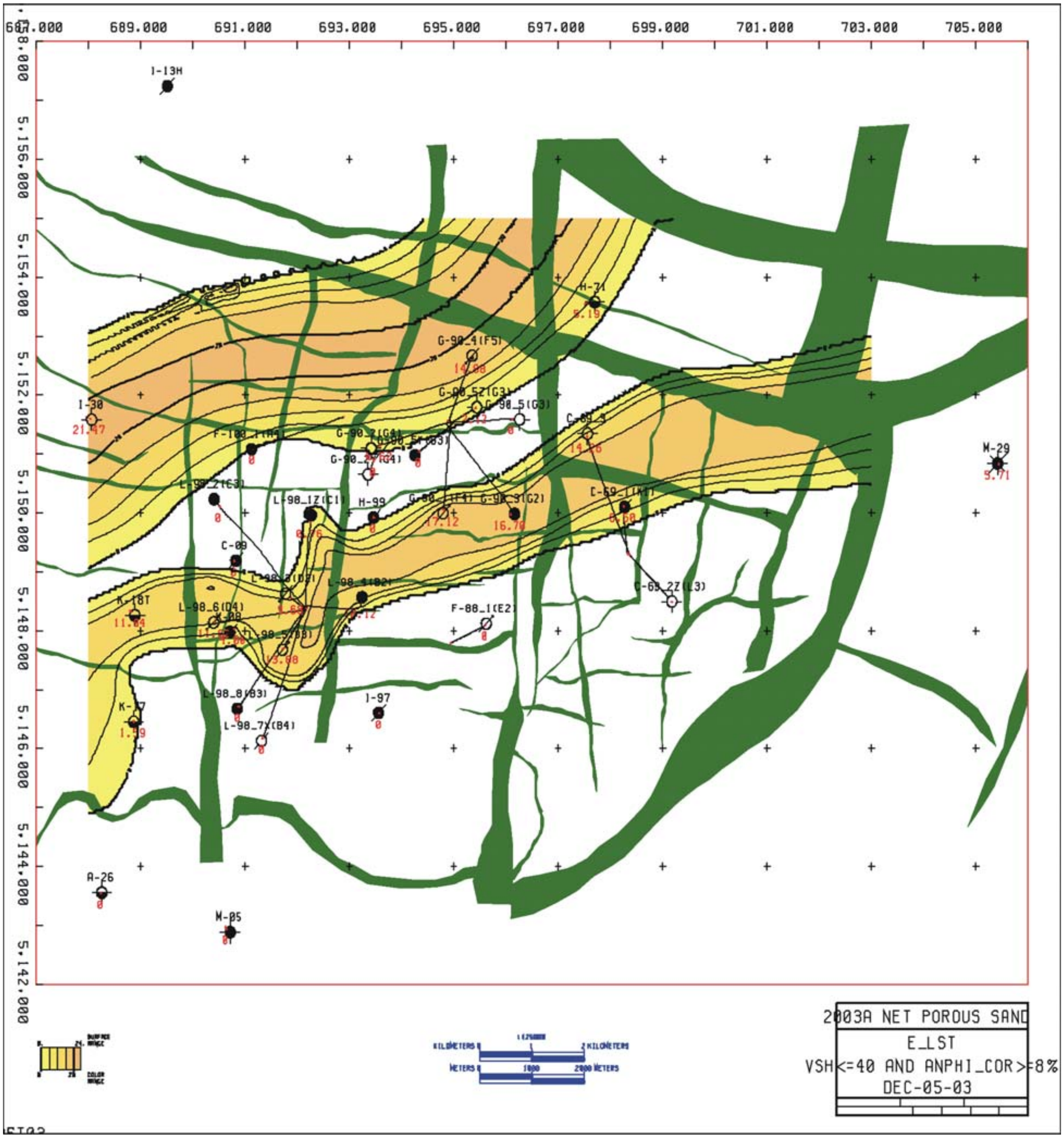
**Terra Nova Development Plan Amendment**
**Decision 2005.02**

The Board approves the Proponent's proposed North Graben exploitation scheme to develop the NGSE and NGCE fault blocks, subject to Condition 2005.02.01 and the conditions contained in its Decision Reports 97.02 and 2002.02. The outstanding conditions are summarized in Appendix C.

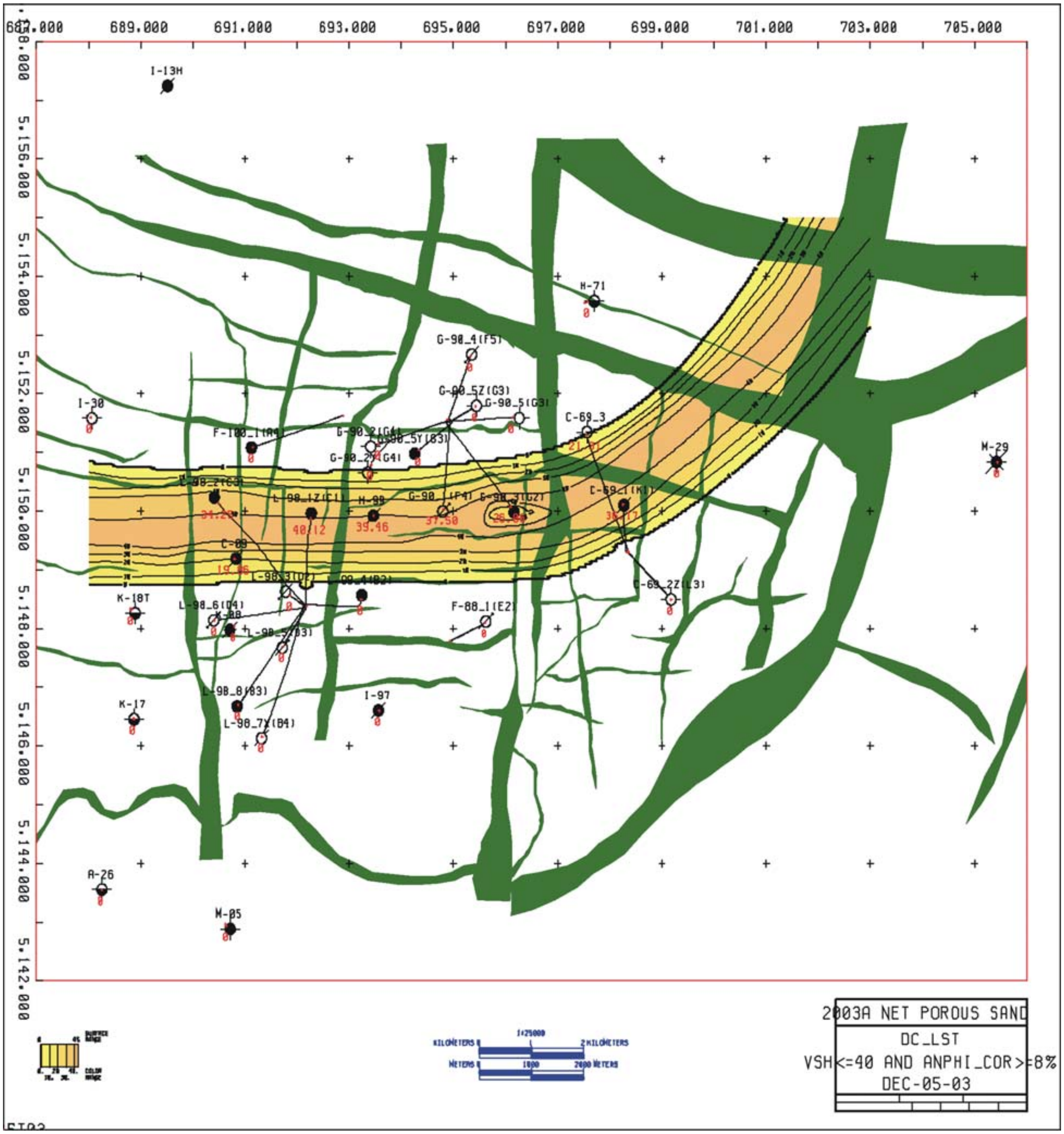
**Condition 2005.02.01**
The Proponent provide a delineation plan, acceptable to the Board, for the North Graben area by September 30, 2008.

# Appendix A

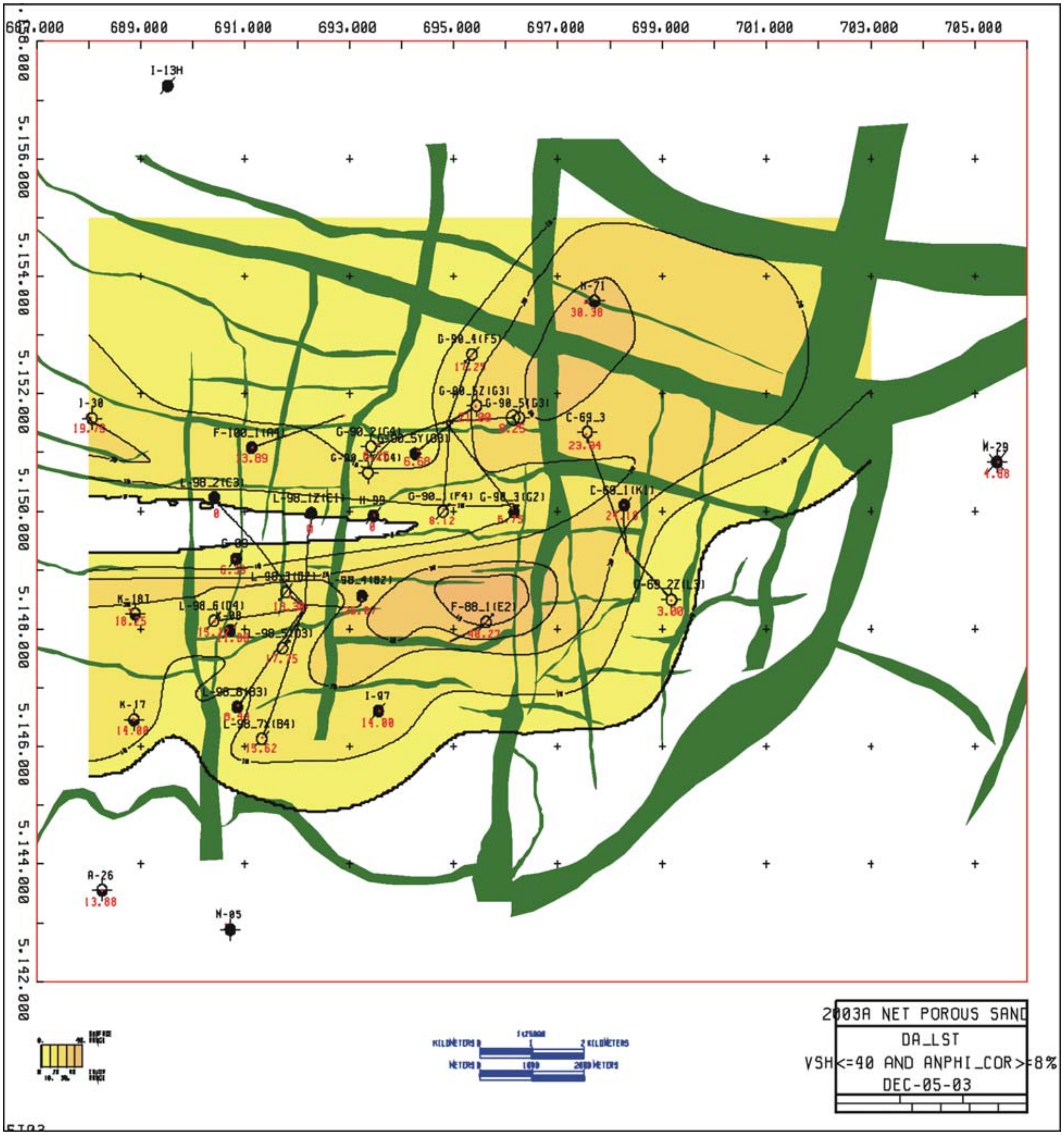
Proponent's Isochores



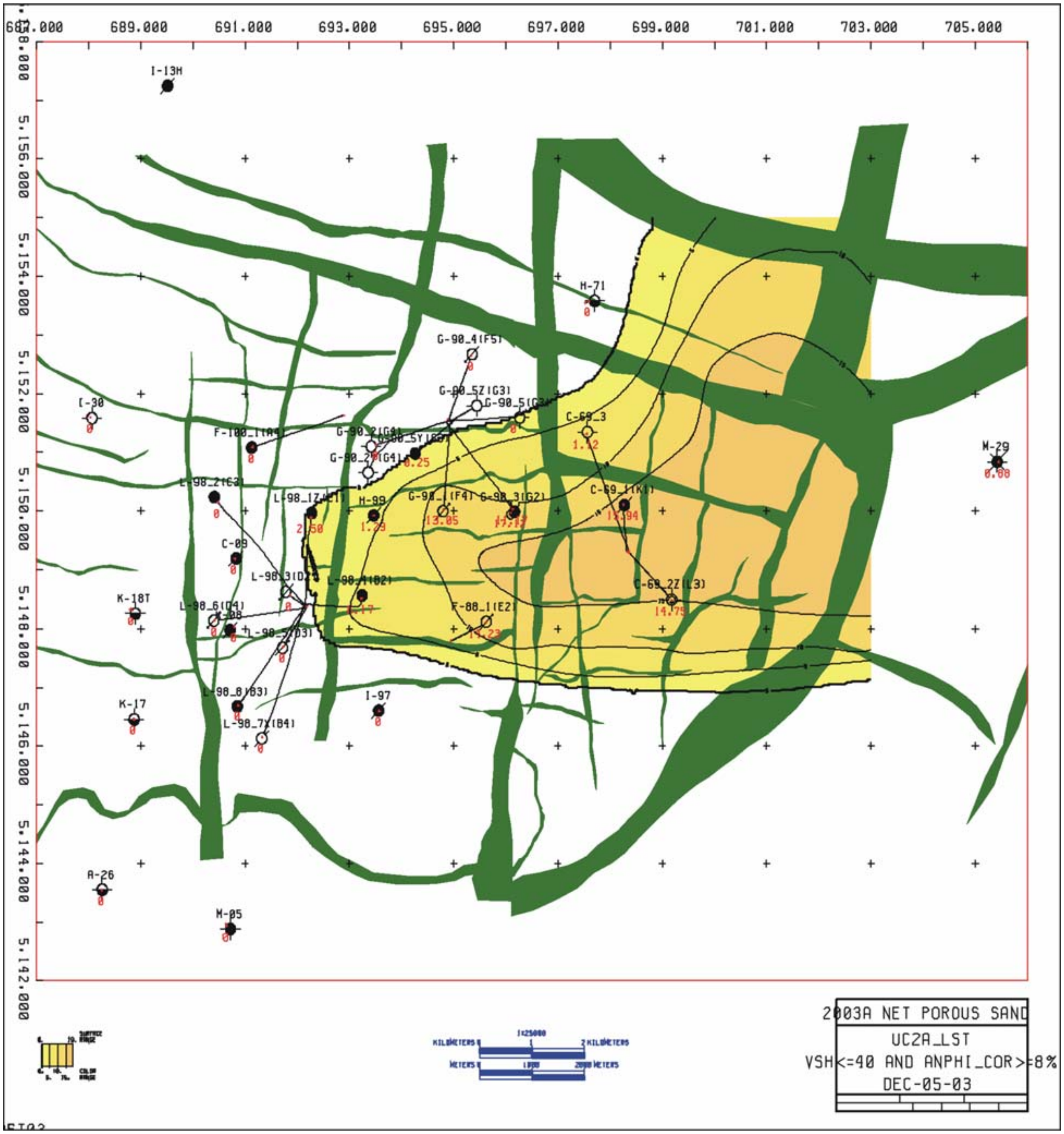

**Proponent's E Sand Isochore**



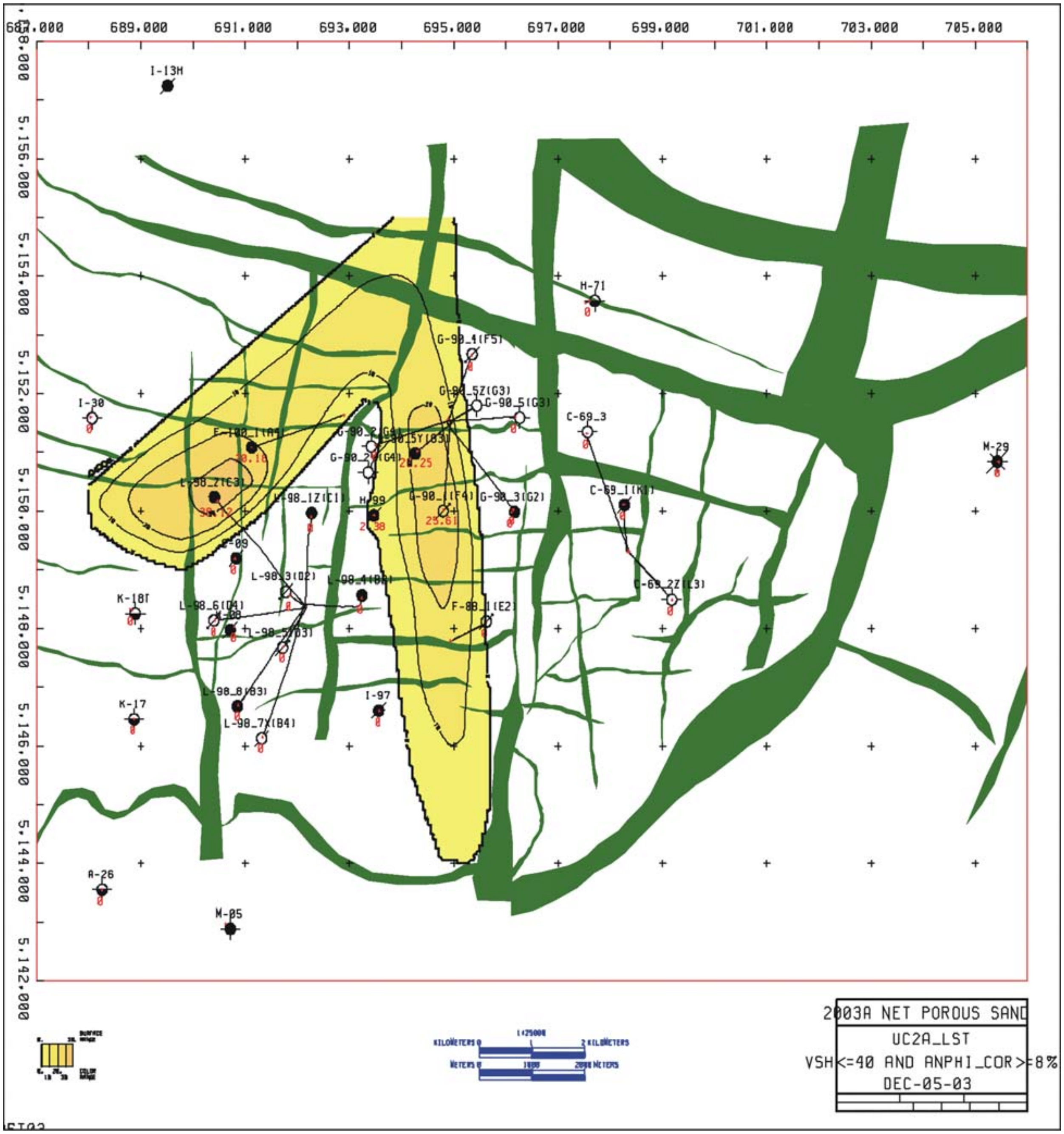

**Proponent's DC Sand Isochore**



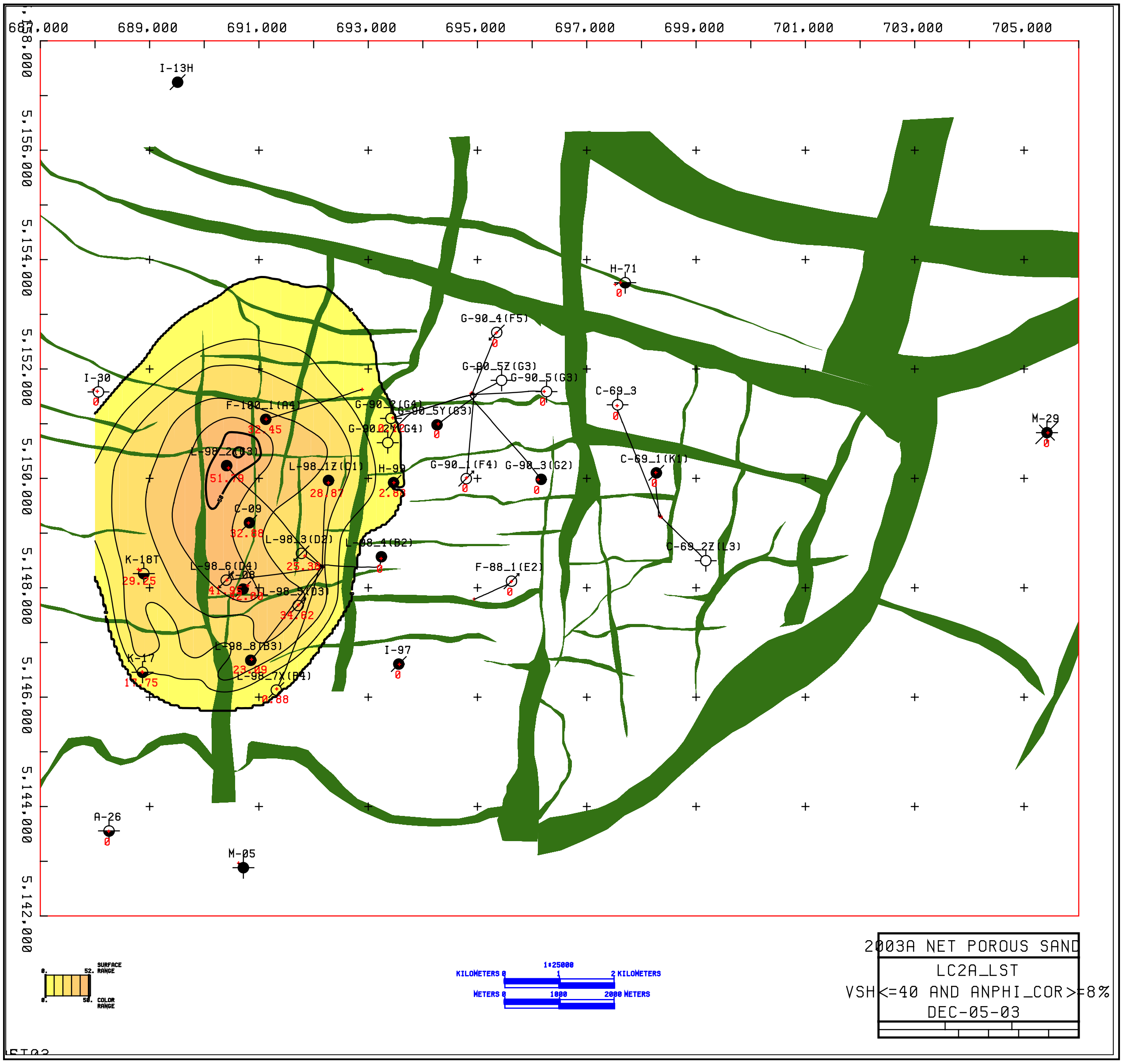

**Proponent's DA Sand Isochore**




**Proponent's UC2C Sand Isochore**



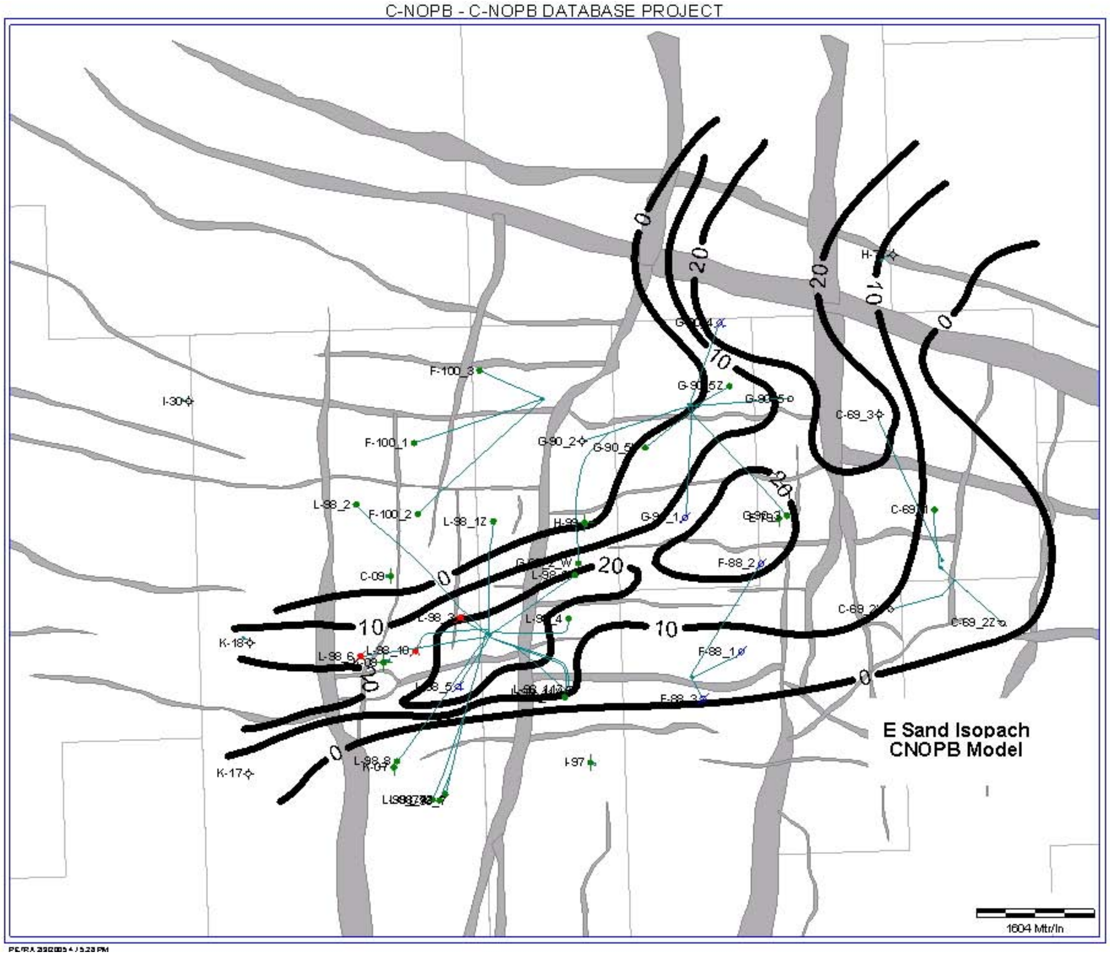

**Proponent's UC2A Sand Isochore**




**Proponent’s LC2A Sand Isochore**

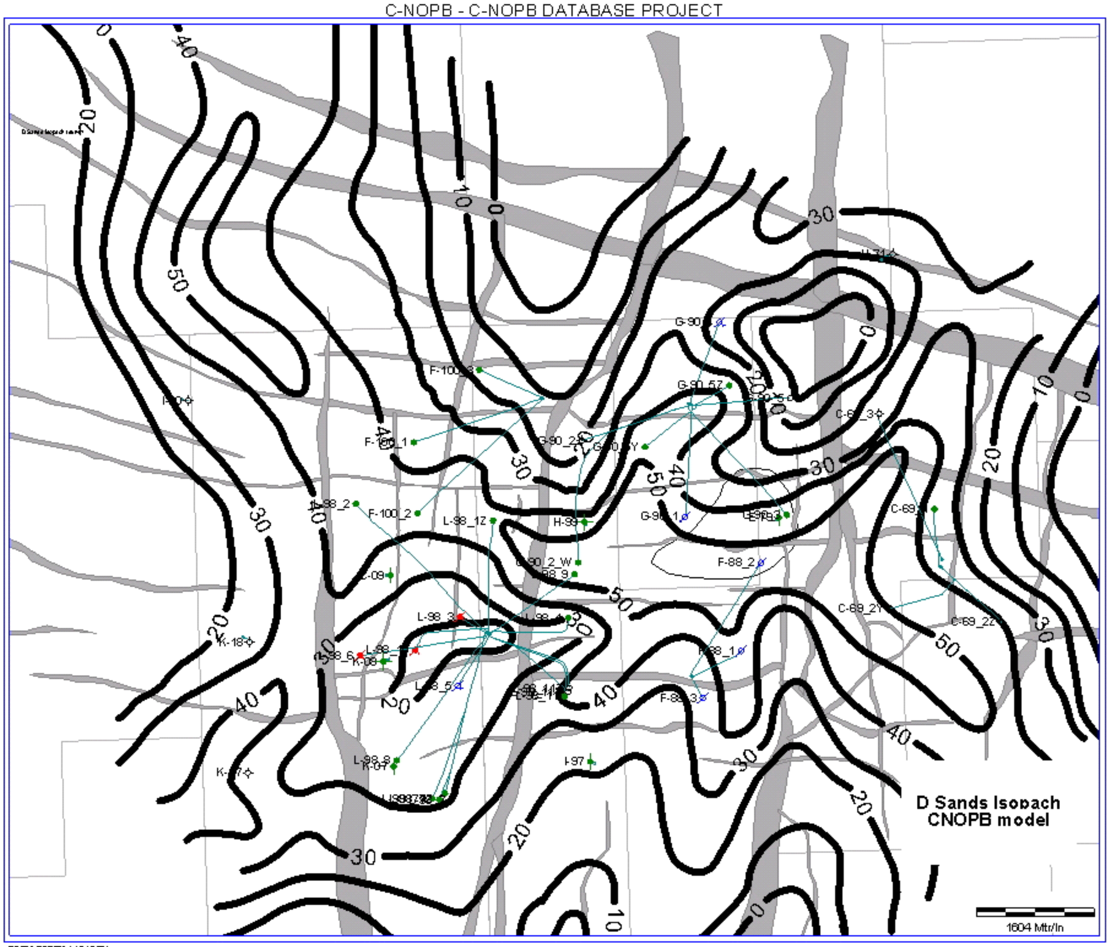
# Appendix B

C-NLOPB's Sand Isopachs

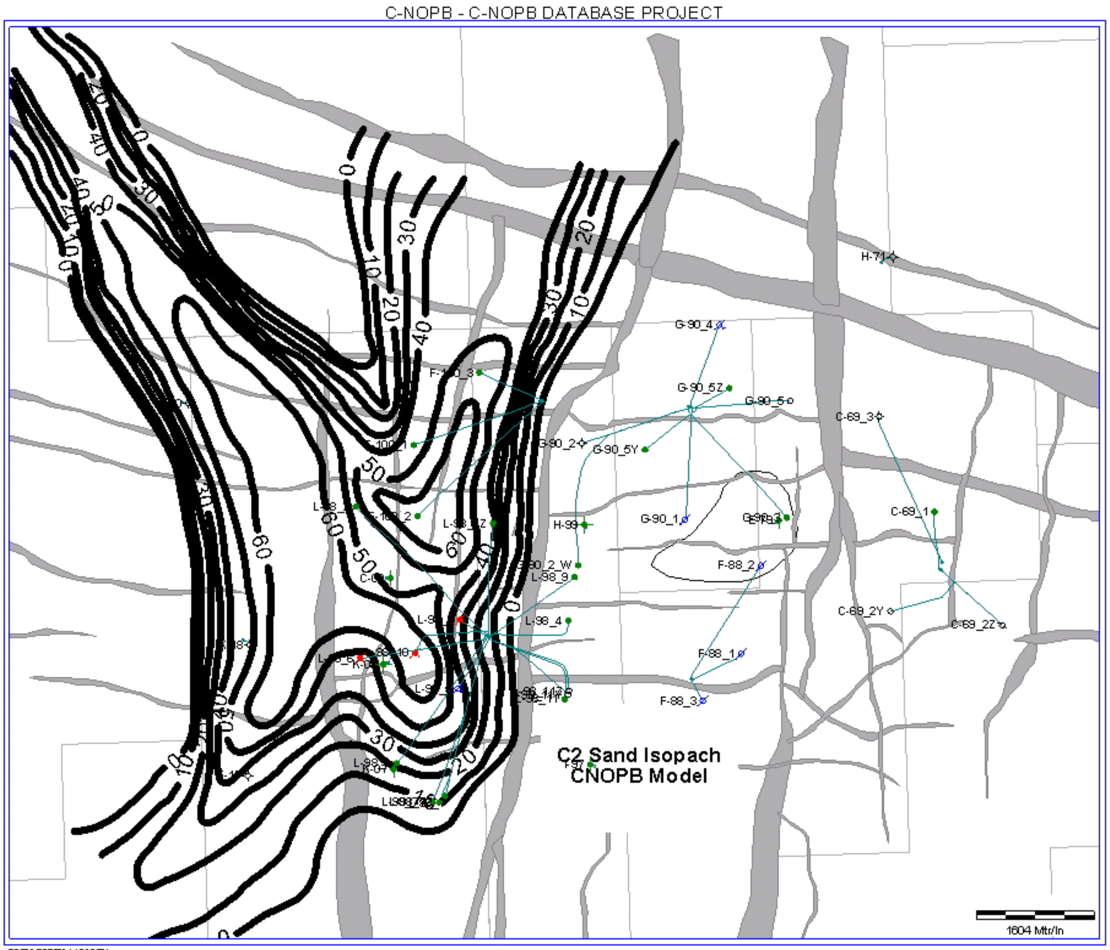



***C-NLOPB's E Sand Isopach***

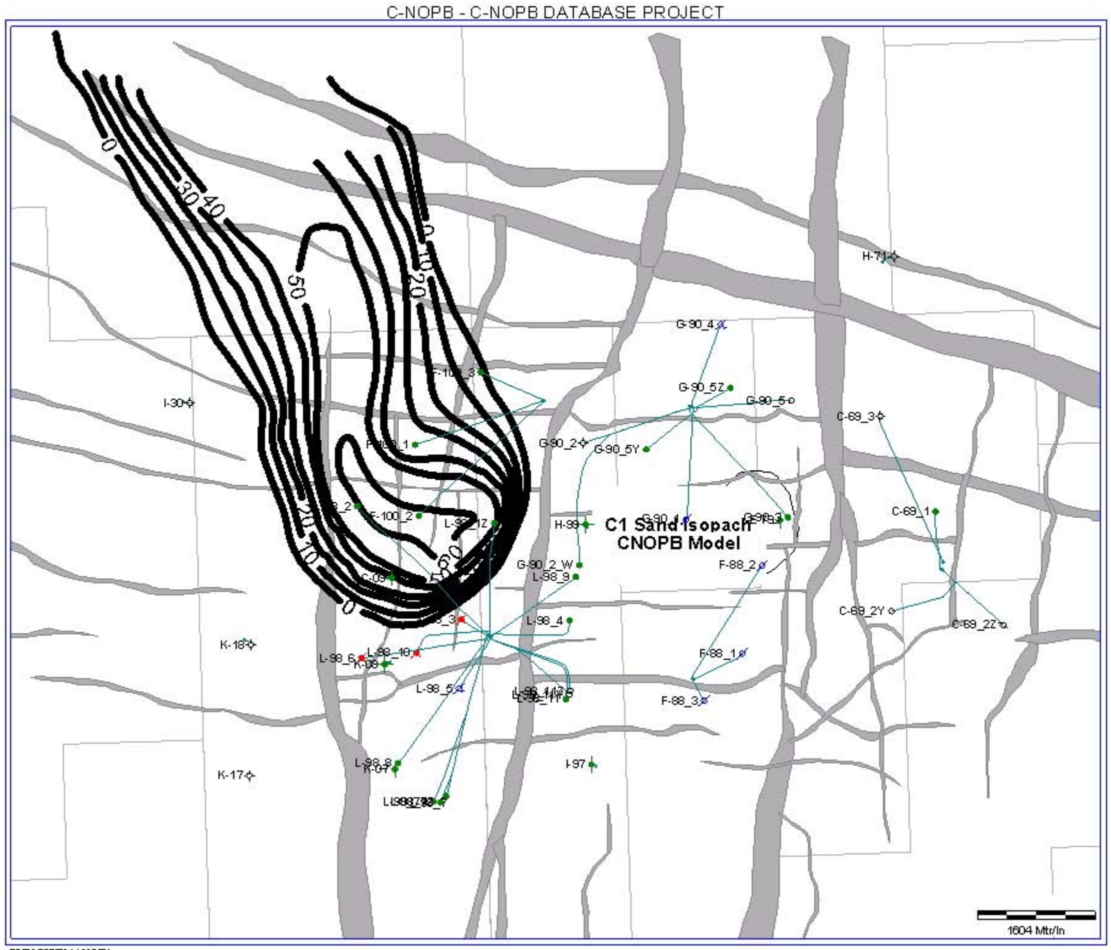
C-NOPB - C-NOPB DATABASE PROJECT




***C-NLOPB's D Sand Isopach***




*C-NLOPB's C2 Sand Isopach*




***C-NLOPB's C1 Sand Isopach***

# Appendix C

## Outstanding Conditions

# Appendix C  Outstanding Conditions

## Terra Nova Development Plan
## Decision 97.02 Status of Conditions

The Board attached twenty-three conditions to its 1997 approval of the Terra Nova Development Plan. The following conditions have not been satisfied:

**Condition 11**
The Proponent submit for the Board's approval an updated exploitation scheme for the Far East portion of the field no later than eighteen months following termination of the first well drilled into this area, as scheduled in the June 1997 *Update to the Application*.

**Status:**

The Proponent submitted an updated exploitation scheme for the Far East on December 1, 2004.

**Condition 12**
The Proponent conduct a study to investigate the effects of gas injection into its alternative site in the Ben Nevis Formation in the area around the King's Cove A-26 and Terra Nova K-17 wells, and report the results to the Board prior to first oil production.

**Status: Rescinded**

On January 19, 1999 the Board considered new information, based on the Proponent's geoscience and engineering studies, that suggested Condition 12 no longer applies, and a requirement to carry out the specified evaluations before first oil is not necessary. The Board concurred with the Proponent's view and rescinded Condition 12 and replaced it with Condition 12a.

**Condition 12a**
Where production information indicates that gas injection may be detrimental to oil recovery, the Proponent present to the Board for approval a plan for gas disposal to ensure maximum recovery of the oil and gas reserves.

**Status: Ongoing**

**Condition 13**
The Proponent submit for the Board's approval an updated exploitation scheme for the North Graben no later than eighteen months following termination of the first well drilled into this area, as scheduled in the June 1997 *Update to the Application*.

**Status:**

> A submission was submitted to the Board on December 21, 2004. Review of this submission has been suspended pending results of the F-100 3 well which is currently being drilled in the North Graben area.

**Condition 14**
The Proponent, prior to initiating construction on the FPSO and its turret, provide confirmation to the Board that it has made provision in its design for an additional test separator and for a second swivel pass in the turret for testing.

**Status: Rescinded**

> On April 21, 1998 the Board considered a request from the Proponent to rescind Condition 14 and determined that further information was required. Proponent subsequently requested to provide additional information. On June 24, 1998, the Board rescinded existing Condition 14 and replaced it with the following:
>
> > The Proponent shall at all times during the operation of the field provide facilities and equipment that, to the satisfaction of the Chief Conservation Officer of the Board, are suitable and adequate to meet the well test requirements set out in the *Newfoundland Offshore Area Production and Conservation Regulations*.
>
> Board's Chief Conservation Officer is monitoring the Proponent's performance with respect to this Condition.

**Condition 21**

i. The Proponent provide in the design of its facilities for the re-injection of produced water, should this be required in the future.
ii. The Proponent undertake and submit to the Board an analysis of the feasibility of produced water re-injection, following the recovery of sufficient volumes of produced water to permit the conduct of such an analysis.
iii. The Proponent proceed with re-injection of produced water if, in the opinion of the Board, it is technically and economically feasible.

**Status:**

i. Satisfied
ii. Awaiting submission
iii. Pending, the Board's decision will depend upon disposition of Conditions 21 (i) and(ii)

**Terra Nova Development Plan Amendment**
**Decision 2002.01 Status of Conditions**

**Condition 2002.01.02**
The Board's Chief Conservation Officer may at any time reduce the production rate if reservoir performance differs significantly from that predicted in the documents entitled ***Application to Increase the Annual Average Oil Production Rate for the Terra Nova Field*** and ***Supplemental Information to Application to Increase the Annual Average Oil Production Rate for the Terra Nova Field*** and the Chief Conservation Officer has reason to believe that production at the approved rate may cause waste.

**Status: Ongoing**

**Condition 2002.01.03**
If substantial modification or additions to the production facilities are necessary to accommodate additional oil production capacity, the Proponent must submit an amendment to the development plan.

**Status: Ongoing**

**Terra Nova Development Plan Amendment**
**Decision 2005.01**

The Board approves the Proponent's proposed Far East exploitation scheme subject to conditions 2005.01.01, 2005.01.02 and 2005.01.03, set out below and the conditions contained in its Decision Reports 97.02 and 2002.02. The outstanding conditions are summarized in Appendix C.

**Condition 2005.01.01**
A delineation well be commenced by December 31, 2008 in the FEN3 area or the land relinquished as proposed the Proponent.

**Status: Ongoing**

**Condition 2005.01.02**
Unless otherwise approved by the Board, a delineation well be commenced by December 31, 2006 and diligently pursued in the Far East south FES fault block.

**Status: Ongoing**

**Condition 2005.01.03**
Within three months of termination of the well in the FES fault block, the Proponent submit a report of the results of the well and an assessment of the development potential of any oil resources encountered.

**Status: Ongoing**

# Appendix D

# Glossary

# Appendix D
# Glossary

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|---|---|
| **Associated gas** | Gas that is in contact with oil. Associated gas may exist as a gas cap which overlays an oil accumulation or as solution gas which is dissolved in the oil under initial reservoir pressure and temperature conditions and released from the oil during normal processing of the oil at surface or when the pressure in an oil reservoir is reduced. |
| **Bg** | Gas formation volume factor |
| **Bo** | Oil formation volume factor |
| **Bw** | Water formation volume factor |
| **bopd** | Barrels of oil per day |
| **bpd** | Barrels per day |
| **clastic** | Pertaining to a rock or sediment composed principally of individual fragments or grains |
| **C-NLOPB** | Canada-Newfoundland and Labrador Offshore Petroleum Board |
| **completion** | The activities necessary to prepare a well for the production of oil and gas or the injection of a fluid |
| **conglomerate** | A clastic sedimentary rock composed of fragments larger than 2 mm in diameter; the consolidated equivalent of gravel |
| **core** | A cylindrical boring of rock from which composition and stratification may be determined |
| **cuttings** | Chips and small fragments of rock that are brought to the surface by drilling mud as it circulates |
| **cw** | Compressibility of water |
| **delineation well** | A well that is drilled to assess the aerial extent of an accumulation of petroleum |

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| **deltaic** | Pertaining to, or like a delta |
| **deno** | Density of oil |
| **development** | "Development" refers to all phases of the Project, from the decision to proceed with construction to abandonment of the field |
| **development well** | Well drilled for the purpose of production of oil or gas or for the injection or disposal of fluid into or from a petroleum reservoir |
| **discovery well** | An exploratory well that encounters a new and previously untapped petroleum deposit; a successful wildcat well |
| **exploration well** | A well drilled to find an oil- or gas-bearing formation |
| **fault** | In the geological sense, a break in the continuity of rock types |
| **FE** | Far East |
| **FF** | Full Field (Graben + East Flank + Far East) |
| **flowline** | (a) A pipeline that takes fluids from a single well or a series of wells to a gathering centre. (b) Seabed piping that connects field components such as wells, manifolds and riser bases |
| **fluvial** | Of or pertaining to a river |
| **formation flow test** | An operation to induce the flow of formation fluids to the surface of a well for the purpose of procuring reservoir fluid samples and determining reservoir flow characteristics |
| **FPSO** | Floating Production Storage Offloading vessel |
| **GEF** | Graben + East Flank |
| **glory hole** | A seabed excavation into which subsea equipment is installed |
| **graben** | A fault-bounded elongate crustal block that is lower in |

| | |
|---|---|
| | elevation relative to adjacent crustal blocks |
| **injection** | The process of pumping gas or water into an oil-producing reservoir to provide a driving mechanism for increased oil production |
| **injection water** | Water pumped into the Formation to maintain reservoir pressure; offshore, injection water is filtered seawater treated with biocides, oxygen scavenging and scale inhibiting agents |
| **logging** | The systematic recording of data using a variety of specialized tools during and after the drilling of a well in order to ascertain the properties of the rocks and fluids of the formation through which the well is drilled |
| **mD** | Millidarcies of permeability |
| **MSRC** | Maximum Safety Related Capacity |
| **NEDC** | North east drill center |
| **non-associated gas** | Gas which is not in contact with oil |
| **NPV** | Net present value |
| **NWDC** | North west drill center |
| **NGSE** | North Graben South East Fault Block |
| **NGCE** | North Graben Central East Fault Block |
| **OIM** | Offshore Installation Manager |
| **permeability** | The capacity of a rock to transmit a fluid |
| **petrophysics** | The study of reservoir properties using data obtained from various logging methods |
| **Pb** | Bubble point pressure- the pressure at which solution gas (gas dissolved in oil) will start to be released from oil |
| **porous** | Used to describe a rock that contains void spaces |

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|---|---|
| **Pres** | Reservoir pressure |
| **Prod** | Production |
| **production platform** | An offshore structure equipped to receive oil or gas from offshore wells where primary processing, compression and pumping are carried out before transportation of the oil or gas to shore |
| **produced water** | Water associated with oil and gas reservoirs that is produced along with the oil and gas. |
| **proponent** | Petro-Canada on behalf of all participating Terra Nova interest holders. |
| **recoverable reserves** | That part of the hydrocarbon volumes in a reservoir that can be economically produced |
| **reservoir** | A subsurface, porous, permeable rock body in which oil or gas has accumulated; most reservoir rocks are limestones, dolomites, sandstones, or a combination of these |
| **sandstone** | Sedimentary rock composed of sand-sized particles. |
| **SBF** | Synthetic-based drilling fluid |
| **SEDC** | South east drill center |
| **SWDC** | South west drill center |
| **sediment** | Solid material, both mineral and organic, that is being or has been transported from its site of origin by air, water or ice |
| **sedimentary rock** | Rocks formed by the accumulation of sediment. The sediment may consist of rock fragments or particles, the remains of animals or plants, the product of chemical action or evaporation, or of mixtures of these materials |
| **seismic** | Pertaining to or characteristic of earth vibration. Also, process whereby information regarding subsurface geological structures may be deduced from sound signals transmitted through the earth |

| | |
|---|---|
| **separator** | A cylindrical or spherical vessel used to separate the components in mixed streams of fluids |
| **shale** | Sedimentary rock consisting dominantly of clay-sized particles, an appreciable amount of which are clay minerals |
| **tcf** | Trillion cubic feet |
| **template** | A design pattern with built-in guides for specific equipment and structures to assure their usefulness |
| **topside (or topsides) facilities** | The oil- and gas-producing and support equipment located on the top of an offshore structure |
| **Tres** | Reservoir temperature |
| **ug** | Gas viscosity |
| **uo** | Oil viscosity |
| **uw** | Water viscosity |
| **wellbore** | The hole drilled by the drill bit |
| **wellhead** | The equipment installed at the top of the wellbore used to support the casing strings installed in the well and the rate of flow of fluids from the well |
| **WI** | Water Injection |