CANADA-NEWFOUNDLAND and LABRADOR OFFSHORE PETROLEUM BOARD

DECISION 2005.01

RESPECTING

THE AMENDMENT TO THE TERRA NOVA DEVELOPMENT PLAN

JUNE, 2005

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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 Proponent had provided little documentation in support of a proposed Far East exploitation scheme. Also, the Board observed that resolution of uncertainties affecting the geological and geophysical interpretations may change the proposed well locations and estimated number of wells required to deplete the oil reserves, particularly in the Far East, and the Board acknowledged the Proponent's stated intention to acquire information to assist in resolution of the uncertainties early in the life of the field. However, the Board observed that "it is likely that more than one well will be required to acquire sufficient information to adequately support a comprehensive development plan for the Far East region". The Board stated that it considered the Proponent's Far East exploitation scheme to be preliminary, given the absence of drilling in the area. Condition 11 of Decision 97.02 required "that 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".

On December 1, 2004 Petro-Canada (the Proponent), on behalf of its partners, submitted the document "***Updated (2004) Exploitation Scheme for the Far East Area of the Terra Nova Field***". On January 21, 2005 the Proponent submitted the documents "***Updated (2004) Exploitation Scheme for the Far East Area of the Terra Nova Field Addendum***" and "***Terra Nova Far East Concept Screening (2004)***" which contained further information requested by the Board. On May 10, 2005, following discussion with the Board's technical staff, the Proponent submitted the document "***Updated (2004) Exploitation Scheme for the Far East Area of the Terra Nova Field Addendum 2***". For the purpose of this report, the Board has considered the information included in the December 1, 2004 application and the information included in the January 21, 2005 and May 10, 2005 submissions to constitute "the Application" under consideration.

In order to determine the best development configuration for the Far East area of the Terra Nova field, the Proponent undertook a concept screening. Six reservoir outcomes were selected and evaluated with four development options. The two leading development options investigated included:

1. Option 3, a separate subsea template located in the existing Far East glory hole and
2. Option 4, extended reach drilling from the Northeast and Southeast drill centers

The Proponent is seeking approval for the latter approach. The only portion of the Far East area proposed for development, at this time, is the Far East central area, which will be developed using extended reach drilling from the Northeast and Southeast drill

centers. Drilling in the Far East area of the field is scheduled to commence in 2005 with the drilling of the first producer-injector pair in the FEC1 block. The second producer-injector pair of wells for the FEC3 fault block will be drilled as sidetracks from well slots as they become available. The timing of these sidetrack wells is dependent upon slot availability or expansion of existing drill centers.

The Proponent notes that the proposed approach results in substantial economic value to both the Proponent and the governments. According to the Proponent, by not proceeding with Option 4, for the refined cost case which considers potential cost reductions, the after tax value loss for the Terra Nova owners is estimated to range from $30 to $100 million, while the loss in royalties and taxes ranges from $40 to $130 million.

Pending approval, production from the Far East area of the field will begin in 2005 with an immediate increase in field production from 16,000 Sm^3/d to 20,000 Sm^3/d (88,000 bbl/d to 126,000 bbl/d). In 2006, production from the Far East will account for 30% of the total field production. The central area of the Far East is estimated to contain P50 reserves of 6.9 10^6 Sm^3 (43 million barrels).
In the Proponent's submission of May 10, 2005, the Proponent also made the following commitments:

- A delineation well shall be drilled in the FES "Drill or Relinquish Area" or the FEC2 "Drill Commitment Area". Should this well not be spudded by the end of Q2 2008, the Proponents will relinquish the lands within this FES "Drill or Relinquish Area";

- A delineation well shall be drilled within the FEN3, FEE or the Terrace areas. Should this well not be spudded by the end of Q2 2008, the Proponent will relinquish the lands within the FEN3 fault block.

The Board believes that if resources are to be exploited to their full potential, it is important that information, particularly from delineation wells, be acquired early to provide for proper planning and exploitation of the resources within the life cycle of the production facilities. The Board considered the Proponent's proposed strategy for delineation drilling and the commitment to drill or relinquish selected areas. The Board concurs with the Proponent's proposal to drill or relinquish in the FEN3 area. However, in respect of the FES and FEC2 areas, the Board's technical staff concluded that there is a low chance of encountering hydrocarbons in the FEC2 fault block and believes that the southern delineation well should target the FES area only, and not the FEC2 area proposed by the Proponent. The Board does not accept the Proponent's proposed drill or relinquishment plan for the Far East south. According to information presented by the Proponent, the Far East south has the greatest chance of encountering additional oil reserves in the Far East area. The economic analysis presented by the Proponent, in support of the alternate exploitation schemes, provided for a well to be drilled prior to

2008. The Board believes that a delineation well is necessary to resolve the technical uncertainty in the Far East southern area and this well should be drilled earlier than 2008.

The technical staff of the Board reviewed the Proponent's Application and concur that from an economic perspective, the proposed approach of developing the Far East FEC1 and FEC3 fault blocks through the Northeast and Southeast drill centers is the best solution. However, with no commitment to install a Far East drill centre, this approach is putting at risk development of further reserves in the Far East area. The Board's technical staff note that the Far East south region has the best potential for additional reserves. With the proposed approach to Far East development, the Proponent has provided for the possible installation of a Far East drill center. However, the Proponent has put at risk a significant volume of reserves, up to 4 million Sm^3 (25 million barrels), that may not be exploited in the future, and has established a threshold reserve level of 5.6 million Sm^3 (35 million barrels) to justify installation of the Far East drill center. Also, without a Far East drill center, the Far East development, in conjunction with North Graben development, will use the remaining six drill slots in the field, thus eliminating flexibility to take advantage of development opportunities or deal with problems with the exploitation scheme in a timely manner should they arise.

Section 29 (1) of the Newfoundland Offshore Area Petroleum Production and Conservation Regulations states "***An operator shall provide for maximum recovery of oil and gas from a pool or field***". Both approaches considered by the Proponent are economic, albeit according to the Proponent the proposed option results in substantial economic value to both the Proponent and the government. The legislation requires that the approach that maximizes oil recovery should be employed. However, in considering "waste", a reduction in the quantity of petroleum that could be ultimately recovered, Section 154 of the Act, which addresses waste, makes reference to "having regard to sound engineering and economic principles". The Board's technical staff reviewed the economic analysis conducted by the Proponent. The staff also conducted its own economic analysis and confirmed the Proponent's view that there may be substantial economic benefit to all stakeholders by proceeding with the proposed approach. This factor must be considered when assessing the development alternatives for the Far East area.
In assessing the proposed exploitation scheme, the following factors should be considered:

- Option 4 allows production to begin earlier, improving the economic benefit and reducing the economic risk if the reserves prove to be lower than expected.
- Proceeding with Option 4 may lead to a reduction in reserves; however, there is an equal chance that sufficient reserves will be identified to support installation of a drill center in the Far East.
- Improvements in drilling capabilities and production technology could reduce the risk of stranding reserves. The Proponent has already made a significant

investment to improve the extended reach capability of the Terra Nova drilling unit. However, even with the improved extended reach capability, it is still not possible to reach the Far East south area from the Northeast drill center.

- While the legislation requires that an operator provide for maximum recovery of oil and gas from a pool, it also requires that the Board have regard for sound economic principles.
- Using sound economic principles, Option 4 is the preferred choice since in most cases it has a substantive economic benefit to the Proponent and governments, particularly if the reserves are lower than anticipated.
- As there are limited production facilities and they have a limited life, it is important that the Terra Nova field be fully delineated in a timely manner to allow for proper planning.

The Board considered requiring a delineation well to be drilled prior to making a decision (i.e. the Board require a well prior to allowing the Proponent to proceed with Option 4). However according to the Proponent, a delineation well in the Far East south will take about 65 days to drill and cost $30.4 million. In addition, the delay in production caused by implementing this option could reduce after tax cash flow to the Proponent by $19 to $28 million and royalties and taxes to the governments by $61 to $67 million. The Board's technical staff conducted its own economic analysis and concur with the Proponent's estimates.

The Board considered all factors, including the technical issues and waste provisions of the legislation, and concluded that given the substantial economic benefits to all stakeholder and the technical risks, it is prudent to proceed with Option 4. Also the Board notes, according to the information provided by the Proponent that the Southern area of the Far East has the best chance of encountering significant oil reserves. The Board believes that a delineation well is required in the Southern area of the Far East, earlier than proposed by the Proponent, to resolve the technical uncertainties and acquire the necessary information to assess the development potential of this area.

The Board has therefore approved the following:

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.

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.

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.

2.0 Present Application

2.1 Background

On August 5, 1996, Petro-Canada (The Proponent), on behalf of its partners, submitted a Development Application for the Terra Nova Field. The original Development Plan for the Terra Nova field presented a preliminary development schedule for the Far East area of the field. The second well to be drilled following first oil production was to be a production well in the Far East area. The Proponent also proposed to drill a water injection well to support production from the area. Based on these results, the Far East development would then be incorporated into the overall depletion strategy for the Terra Nova Field. The preliminary development plan for the Far East area of the field included 6 producers and 6 injectors, with production from the Far East beginning in 2005.

The Board approved the Terra Nova Development Plan in Decision 97.02 with several conditions. In Decision 97.02, approving the Terra Nova field Benefits and Development Plan, the Board noted that the Proponent had provided little documentation in support of a proposed Far East exploitation scheme. Also, the Board observed that resolution of uncertainties affecting the geological and geophysical interpretations may change the proposed well locations and estimated number of wells required to deplete the oil reserves, particularly in the Far East, and the Board acknowledged the Proponent's stated intention to acquire information to assist in resolution of the uncertainties early in the life of the field. However, the Board observed that "it is likely that more than one well will be required to acquire sufficient information to adequately support a comprehensive development plan for the Far East region". The Board stated that it considered the Proponent's Far East exploitation scheme to be preliminary, given the absence of drilling in the area. Condition 11 of Decision 97.02 required "that 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".

In November 2001, the Proponent finished drilling the first well, C-69 1, in the Far East area of the field. In July, 2003 the Proponent submitted the document "***Updated Exploitation Scheme for the Far East Area of the Terra Nova Field***" to satisfy Condition 11 of Decision 97.02. The exploitation scheme described in this submission was conditional upon favorable drilling results in the Far East area to prove up threshold reserves necessary for the Far East development to proceed. Later in 2003, following disappointing results from the C-69 3 well drilled in the Far East area of the field, Petro-Canada withdrew this application and undertook a reassessment of the Far East area potential reserves and development options.

On December 1, 2004 Petro-Canada, on behalf of its partners, submitted the document "***Updated (2004) Exploitation Scheme for the Far East Area of the Terra Nova Field***".

On January 21, 2005 the Proponent submitted the documents "***Updated (2004) Exploitation Scheme for the Far East Area of the Terra Nova Field Addendum***" and "***Terra Nova Far East Concept Screening (2004)***" which contained further information requested by the Board. On May 10, 2005, following discussion with the Board's technical staff, the Proponent submitted the document "***Updated (2004) Exploitation Scheme for the Far East Area of the Terra Nova Field Addendum 2***" which contained the Proponent's commitments related to delineation drilling in the Far East area of the field. The current Application from Petro-Canada proposes to utilize existing drilling slots located in the Northeast and Southeast drill centers in the East Flank area of the field. The only portion of the Far East area proposed for development, at this time, are the Far East central blocks which will be developed using extended reach drilling from the Northeast and Southeast drill centers.

For the purpose of this Decision Report, the Board has considered the information included in the December 1, 2004 application and the information included in the January 21, 2005 and May 10, 2005 submissions to constitute "the Application" under consideration. The following section of the report presents an overview of the Proponent's Application provided December 1, 2004 and the further submissions provided on January 21, 2005 and May 10, 2005.

2.2 Proponent's Application

On December 1, 2004, the Proponent submitted the document "***Updated (2004) Exploitation Scheme for the Far East Area of the Terra Nova Field***" to satisfy Condition 11 of Decision 97.02. The Application includes Petro-Canada's latest interpretation of the Far East area of the Terra Nova field and outlines the Proponent's current development plans for the Far East.

On December 17, 2004 the Proponent met with the Board's technical staff to discuss the Application and on January 21, 2005, the Proponent submitted the documents "***Updated (2004) Exploitation Scheme for the Far East Area of the Terra Nova Field Addendum***" and "***Terra Nova Far East Concept Screening (2004)***" which contained further information requested by the Board. On May 10, 2005, following discussion with the Board's technical staff, the Proponent submitted the document "***Updated (2004) Exploitation Scheme for the Far East Area of the Terra Nova Field Addendum 2***".

2.2.1 Geological Model

The current geological model being used by the Proponent is the 2003A model. This model has been updated to include all wells up to F-100 1. Wells drilled subsequent to F-100 1 have not substantially affected the geological interpretation in the Far East. The geological interpretation is based on an alluvial / fluvial to marginal marine deposition within a braidplain / braid delta setting. The Proponent's Jeanne d'Arc stratigraphy for this depositional system is provided in Figure 1. The Proponent's isochores for each of the oil-bearing sands is included in Appendix A.

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

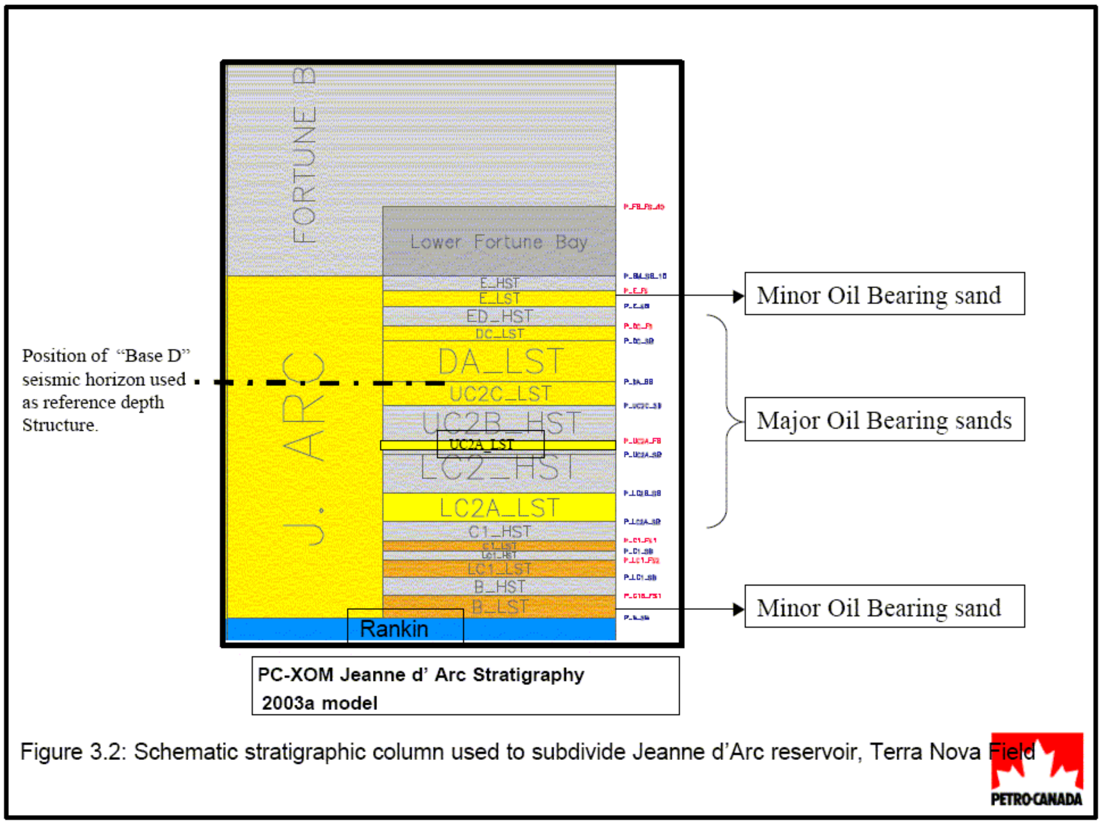


Figure 3.2: Schematic stratigraphic column used to subdivide Jeanne d'Arc reservoir, Terra Nova Field

2.2.2 Basic Reservoir Data

Three wells have been drilled in the Far East area of the field to date. Pressure data acquired from these wells indicates that the Far East region is approximately 6,500 kPA higher than that seen in the Graben and East Flank areas. The reference pressure for the Far East area of the field is 41.3 MPaa at -3,300 mTVDss. The C-69 1 well, drilled in the FEC1 fault block, encountered 80 m of oil bearing sand with an oil-down-to of -3,443 mss. The C-69 2Z well, which was drilled in the FEC2 fault block, encountered a thick reservoir section with limited porosity. The C-69 3 well, drilled into the FEN1 block, encountered 61 m of net porous sand, which was all water bearing. A consistent water gradient of 9.94 kPa/m was calculated over the sand intervals in the C-69 3 well. This water gradient intersects the oil gradient from the C-69 1 well at -3,473 mss, suggesting a common fluid gradient in the Far East.

Bottomhole fluid samples were acquired from the C-69 1 and C-69 2Z wells. The samples were all subject to contamination since they were taken under open hole conditions. Decontamination exercises were conducted and samples taken from the C-69 1 well were chosen for full PVT analysis. According to the Proponent, the fluid sample acquired from the Da sand in the C-69 1 well is considered the most representative for the Far East area. A water analysis was also conducted from a formation water sample taken from the C-69 2Z well in the lower UC2 sand interval. The water analysis indicated that the level of calcium and sulfate was significantly higher in the Far East formation water. A summary of the Far East PVT properties is shown in Figure 2, along with the PVT properties for the Graben and East Flank areas of the field.

2.2.3 Oil-in-Place and Reserve Estimates

In its Application, the Proponent presented volumetric assessments of stock tank original oil-in-place (STOOIP) that are based on the 2003A geological model for the Jeanne d'Arc reservoirs. The Proponent's original oil-in-place estimate for the entire Far East area is 28.4 x 10^6 Sm^3 (179 million barrels).The two central fault blocks, FEC1 and FEC3, are the only two fault blocks currently proposed for development, as seen in Figure 3. Table 1 presents the Proponent's deterministic original oil-in-place volumes for the Far East area. The two fault blocks proposed for development, FEC1 and FEC3, contain 11.70 10^6 Sm^3 (74 million barrels) and 2.99 10^6 Sm^3 (19 million barrels) original oil-in-place, respectively.

The Far East has an inferred oil-water-contact of -3,473 mss based on the intersection of the C-69 1 oil gradient and the C-69 3 water gradient. This oil-water contact has been used to calculate the original oil-in-place estimates presented in Table 1.

An assessment of the potential opportunities to increase oil reserves in the Far East area was undertaken by the Proponent. According to the Proponent, further potential exists in the Far East south area in the Jeanne d'Arc and Upper and Lower Hibernia formations, the Terrace block in the Jeanne d'Arc formation and the Horst block in the Jeanne d'Arc formation. The Proponent has also conducted an unrisked probabilistic assessment of the reserve volumes for each of the prospective reservoirs. A summary of this assessment is presented in Table 2. The central area of the Far East that is proposed for development, is estimated to contain P50 reserves of 6.9 10^6 Sm^3 (43 million barrels). The P50 reserve estimate for the entire Far East area is estimated to be 30.3 10^6 Sm^3 (190 million barrels).

The chance of success (COS) was also thoroughly evaluated for all of the Far East opportunities. The contributing chance factors that were examined included source, seal, reservoir and structure. Because the Far East central area has been proven by drilling the C-69 1 well, the chance of success for this area is 100%. Based on the chance of success and the reserves distribution, risked reserves for each of the Far East opportunities were calculated. Table 3 presents a summary of the risked reserves for the different Far East opportunities. The Far East central area proposed for development contains risked reserves of 7.94 10^6 Sm^3 (50 million barrels). Most of the remaining Far East opportunities carry a low chance of success, and therefore have lower risked reserves.

Figure 2: Terra Nova PVT Properties (Source: After Petro-Canada 2004)

General Terra Nova PVT Properties (Full-Compression)

Property	Units	PVT Region 1	PVT Region 2	PVT Region 3
Sample		PG2 S36 MEAN	E792-32	D249-11
Depth	mSS	3456	3209	3361
Pres	bara	358.14	340.87	417.39
Pb	bara	231.6	227.8	310.00
Tres	C	96	90	93.7
Bo @ Pres	rm3/Sm3	1.398	1.375	1.502
Bo @ Pb	rm3/Sm3	1.436	1.407	1.536
Bg @ Pres	rm3/Sm3	0.00368	0.00373	0.00336
Bg @ Pb	rm3/Sm3	0.00505	0.00504	0.00404
Bw @ Pres	rm3/Sm3	1.032	1.029	1.030
Rs	Sm3/Sm3	141.57	133.70	186.43
deno @ Pres	kg/m3	711.89	716.97	675.96
Oil Gradient	bar/m	0.06981	0.07031	0.066
deno @ Pb	kg/m3	692.97	700.26	659.39
deno @ ST	kg/m3	852.89	856.78	840.23
API		34.41	33.65	36.91
deng @ Pb	kg/m3	181.39	176.48	234.38
deng @ ST	kg/m3	1.0077	1.0059	0.9489
gas gravity		0.824	0.822	0.776
Salinity	ppm	72500	72500	72500
denw @ ST	kg/m3	1051.9	1051.9	1051.9
cw	bar^{-1}	4.295E-05	4.263E-05	4.245E-05
uo @ Pres	cp	0.6920	0.7602	0.5059
uo @ Pb	cp	0.4627	0.5346	0.4131
ug @ Pres	cp	0.0255	0.0234	0.0409
ug @ Pb	cp	0.0229	0.0215	0.0347
uw @ Pres	cp	0.364	0.379	0.367

PVT-1 (Graben & N. Graben)
PVT-2 (East Flank)
PVT-3 (Far East)

Figure 3: Far East Fault Block Identification (Source: After Petro-Canada 2004)

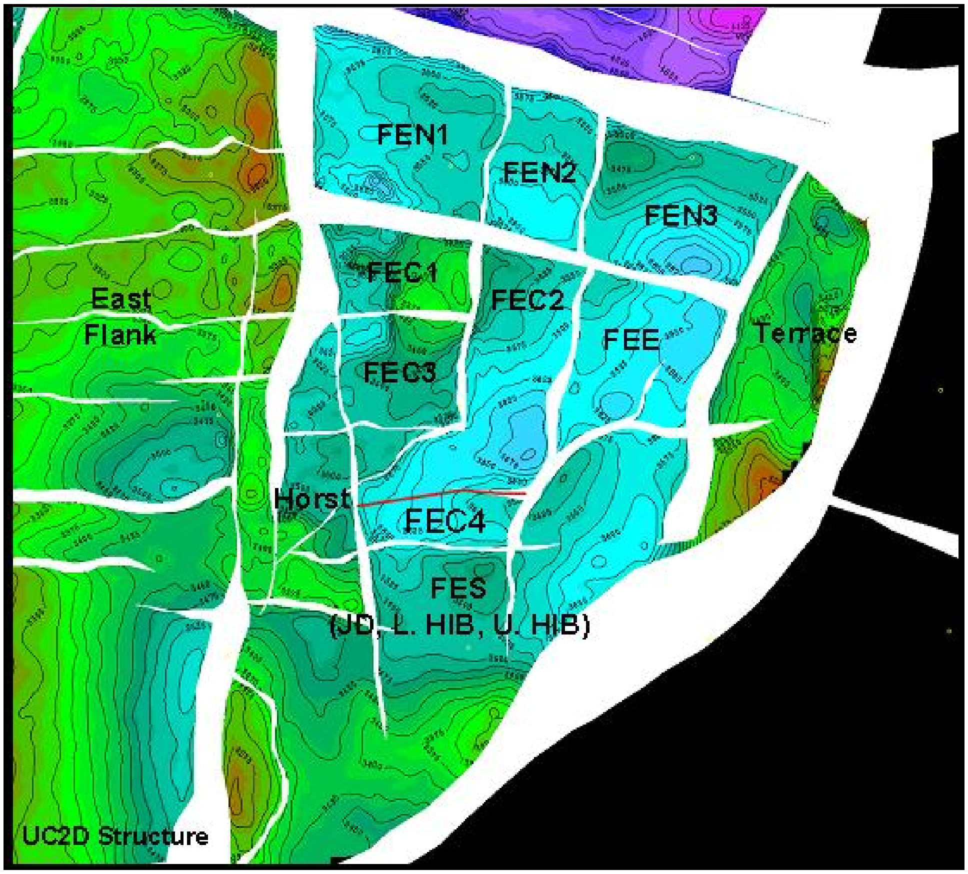


Table 1: Proponent's Far East Deterministic STOOIP Volumes (Source: After Petro-Canada 2004)

Fault Block	E sand	D sand	C sand	Total
FEC1	1.26	8.37	2.07	11.70
FEC2	0.10	0.74	0.00	0.84
FEC3	0.06	2.59	0.34	2.99
FEC4	0.00	0.00	0.00	0.00
FEN1	2.28	4.20	0.00	6.48
FEN2	1.67	0.24	0.00	1.91
FEN3	1.62	0.62		2.24
FEE	0.00	0.00	0.00	0.00
Horst				2.25
Total (million Sm^3) **Total (million barrels)**	**6.99** **43.97**	**16.76** **105.42**	**2.41** **15.16**	**28.41** **178.69**

Table 2: Proponent's Probabilistic Reserve Distributions (Source: After Petro-Canada 2004)

Reserves $10^6 m^3$	FEC	HORST	TERRACE	FEN1	FEN3	FEN2	FEE	FES JDA	FES UHIB	FES LHIB
Minimum	1.1	0.3	2.1	0.1	0.1	0	0	0.1	0.1	0
Maximum	40.1	21.3	40.1	348.6	13.2	21.3	3490.3	9275.3	122.8	80.8
Mean	7.5	1.7	9	3.2	1	0.2	2.9	9.4	4.7	3.3
Standard Deviation	4	1.4	4.2	5.7	0.7	0.4	35.2	93.9	4.9	4.8
Variance	16.2	1.8	17.6	31.7	0.5	0.1	1229.6	8738.2	23.3	22.9
Skewness	1.8	5.8	1.6	32.8	2.9	21.48	96.93	96	4.5	5.5
Kurtosis	8.9	59	7.8	1778.2	22.93	988.27	9589.89	9462.3	54.8	54.3
Number of Errors	0	0	0	0	0	0	0	0	0	0
Mode	5.3	1.1	6.5	1.1	1.1	0.1	0.4	7.3	3	2.5
95%	2.8	0.8	4.3	0.5	0.3	0	0.1	0.9	0.7	0.2
90%	3.4	0.9	5.1	0.7	0.4	0	0.2	1.3	1	0.4
85%	3.9	1	5.6	0.8	0.4	0	0.3	1.6	1.3	0.5
80%	4.3	1	6	1	0.5	0.1	0.4	1.9	1.5	0.7
75%	4.8	1.1	6.5	1.1	0.5	0.1	0.5	2.3	1.8	0.8
70%	5.2	1.2	6.8	1.3	0.6	0.1	0.6	2.6	2.1	1
65%	5.6	1.2	7.2	1.4	0.6	0.1	0.7	3	2.3	1.2
60%	6	1.3	7.6	1.6	0.7	0.1	0.8	3.5	2.6	1.4
55%	6.4	1.4	8.1	1.8	0.7	0.1	1	3.9	2.9	1.6
50%	6.9	1.4	8.5	2	0.8	0.1	1.1	4.4	3.3	1.8
45%	7.3	1.5	8.9	2.3	0.9	0.2	1.3	5.1	3.7	2.1
40%	7.8	1.6	9.4	2.6	1	0.2	1.6	5.8	4.1	2.4
35%	8.4	1.7	10	2.9	1	0.2	1.8	6.6	4.6	2.8
30%	9.1	1.8	10.6	3.3	1.1	0.2	2.2	7.6	5.1	3.3
25%	9.9	1.9	11.4	3.8	1.3	0.3	2.6	8.9	5.8	3.9
20%	10.8	2.1	12.1	4.4	1.4	0.3	3.3	10.9	6.7	4.6
15%	12.1	2.3	13.2	5.2	1.6	0.4	4.1	13.7	7.8	5.7
10%	13.9	2.7	14.7	6.6	1.8	0.5	5.8	18.2	9.7	7.3
5%	17.3	3.6	17.2	9.2	2.3	0.7	9.2	28	13.5	11
Coeff of Variation	54%	81%	47%	177%	72%	167	1216%	999%	104%	147%

Table 3: Far East Risked Reserves (Source: After Petro-Canada 2004)

Opportunity	Det. ML MMbbl	P90 MMbbl	P50 MMbbl	P10 MMbbl	COS %	Risked Reserves MMbbl
FEC	40	21	**43**	87	100	**50**
FEN1	14	4	**13**	41	72	**13**
FEN2	4	0	**1**	3	72	**1**
FEN3	5	2	**5**	11	28	**2**
TERRACE	41	32	**53**	92	8	**5**
FEE	1	1	**7**	36	3	**0**
HORST	7	5	**9**	17	36	**4**
FES J'DARC	43	8	**28**	114	11 - 29	**5 - 14**
FES UHIB	18	6	**21**	61	32 - 41	**9 - 12**
FES LHIB	18	2	**11**	46	38 - 48	**7 - 9**

2.2.4 Far East Concept Screening

To determine the best development configuration for the Far East area of the Terra Nova field, the Proponent completed a concept screening study. Six reservoir outcomes were selected and evaluated with four development options. The six reservoir outcomes considered are shown in Figure 4. Figure 5 presents the two leading development options investigated, labeled "Option 3" and "Option 4". Option 3 includes a separate subsea template located in the existing Far East glory hole. Option 4 would use extended reach drilling from the Northeast drill center to develop the Far East central area. Remaining Far East opportunities would then be developed through a new Far East drill center. Other development options were also considered, including a new drill center located in the Far East south area and expansion of the Northeast drill center. The Proponent found the option of locating a new drill center in the Far East south to be technically, economically and strategically inferior to the centrally located drill centre (i.e. Options 3 and 4). According to the Proponent, the option to expand the Northeast drill center is still under consideration as it fits well with the preferred option; but is considered a future initiative and has not been studied in detail. The Far East area reservoir scenarios and configurations evaluated by the Proponent are provided in Table 4.

The two main development options in Figure 4 are illustrated with the reservoir "c" scenario. With this reservoir scenario, both development options would require a separate Far East drill center, which would be tied back to the FPSO. With Option 4, the Far East central opportunities would be developed using the Northeast drill center, allowing acceleration of the FEC block development. The facility costs for the two development options are approximately equal, however the drilling costs are higher for Option 4. This is because the FEC1 block would require a re-drill of the C-69 1 well, and the drilling costs would be higher due to the need for extended reach drilling from the Northeast drill center.

The Proponent states that concept screening evaluation demonstrates that Option 4, development of the Far East central block from the Northeast drill center, is the preferred solution economically. Option 4 allows for accelerated development of the Far East central area and provides long term production, which is deemed necessary in order to reduce the uncertainty in the remaining opportunities and justify installation of the Far East drill center. According to the Proponent, there is significant value loss to all stakeholders associated with not proceeding with this recommended strategy and delaying development of the Far East by 1-2 years. The after tax value loss, for the unrefined cost case which does not consider potential cost reductions, can range from between \$6 to \$85 million for the owners (Figure 6) and \$12 to \$123 million for the governments (Figure 7). For the refined cost case, which considers potential cost reductions, the after tax value loss for the Terra Nova owners is estimated to range from \$30 to \$100 million (Figure 8), while the loss in royalties and taxes ranges from \$40 to \$130 million (Figure 9). The Proponent notes that this value loss is primarily due to the delay in development of the Far East Central fault block and the impact that has on the production profile. The break-even reserve size for the Far East South to offset the added value from proceeding with Option 4 was assessed by the Proponent by comparing Case 3c to Case 4a over the range of reserves. The Proponent states that this assessment determined the break-even reserve size to be approximately 4.0 million Sm^3 (25 million barrels).

The Proponent has also assessed the threshold reserves necessary to justify a new subsea development (i.e. a separate drill center in the Far East). To establish the threshold reserves, a rate of return of 20% and a DPI (discounted profit to investment ratio) of 0.30 were used. For the Far East south opportunity, the Proponent stated that a threshold reserve level of 5.5 million Sm^3 (35 million barrels) would be necessary in order for the development to be economic. For reserve outcomes greater than 5.5 million Sm^3 (35 million barrels), the development would be economic on a stand-alone basis, however at reserves levels less than 4.0 million Sm^3 (25 million barrels) the development would be uneconomic. According to the Proponent, given the current risked reserve distribution for the Far East south area, there is a greater than 90% probability that the Far East south area can be incorporated into the development strategy proposed. Also, the results from the concept screening evaluation show that the recommended development strategy for the Far East central block is not dependent on delineation drilling in the Far East south.

Figure 4: Proponent's Far East Reservoir Scenarios (Source: After Petro-Canada 2005)

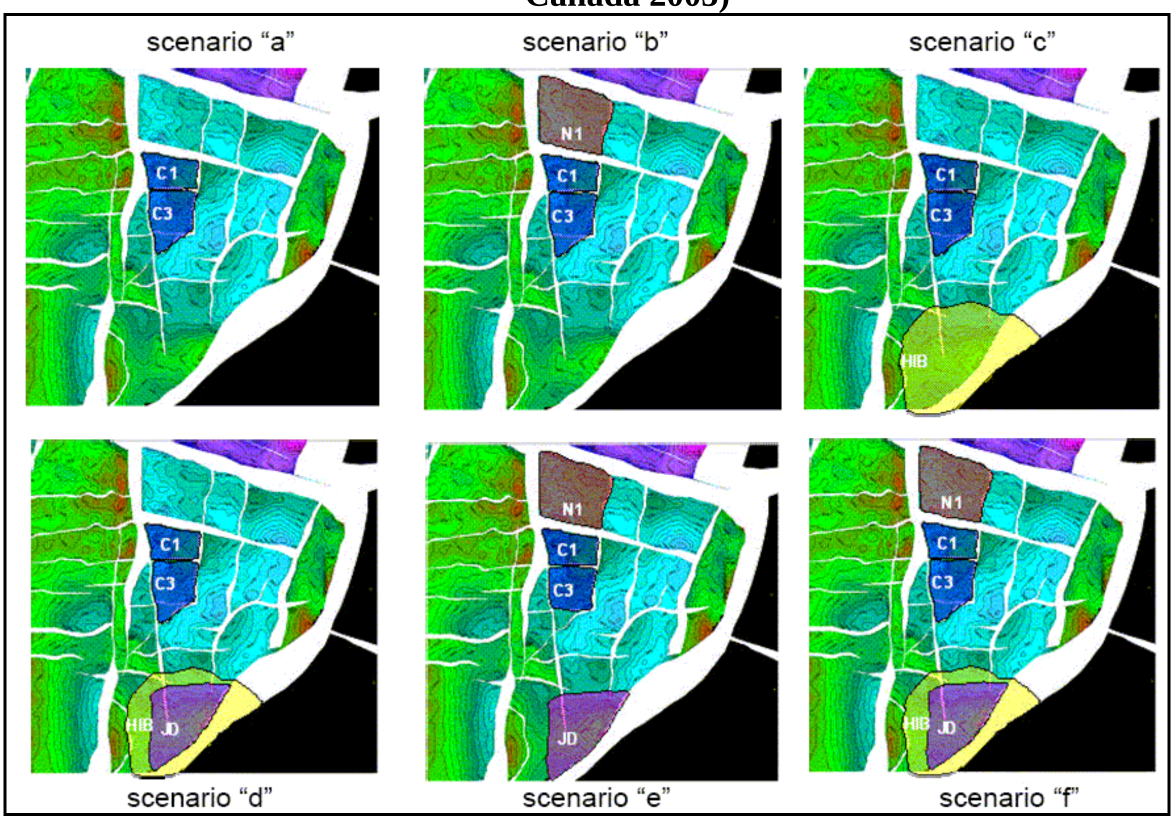


Figure 5: Proponent's Far East Development Configurations (Source: After Petro-Canada 2005)

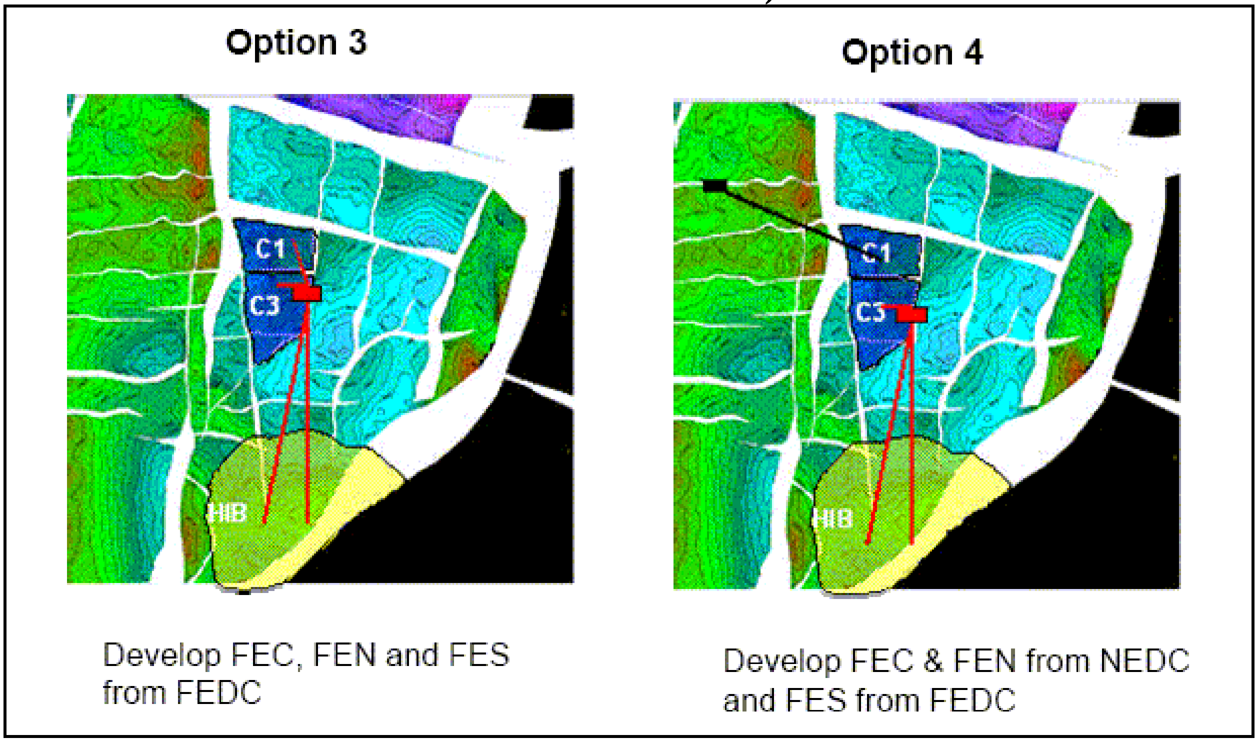


Table 4: Far East Scenarios and Configurations Concepts Screening (Source: After Petro-Canada 2004)

Ref #	Case	Configuration	FEC	FEN	FES JD	FES HIB	FE Wells	Scenario	Reserves MMbbl
	3a	FEDC FPSO Tieback	4				4	FEC	43
	3b	(2007)	4	2			6	FEC + N1	56
	3c	"	4			4	8	FEC + FES(HIB)	75
	3d	"	4		2	4	10	FEC + FES(JD + HIB)	103
	3e	"	4	2	2		8	FEC + N1 + FES(JD)	84
	3f	"	4	2	2	4	12	FEC + N1 + FES(JD + HIB)	116
	4a	NEDC Drilling	4				4	FEC	43
	4b	"	4	2			6	FEC + N1	56
	4c	+ FEDC (2007)	4			4	8	FEC + FES(HIB)	75
	4d	"	4		2	4	10	FEC + FES(JD + HIB)	103
	4e	"	4	2	2		8	FEC + N1 + FES(JD)	84
	4f	"	4	2	2	4	12	FEC + N1 + FES(JD + HIB)	116

***Figure 6:* Concept Screening and Economics: After Tax Cash Flow Difference (Source: After Petro-Canada 2005)**

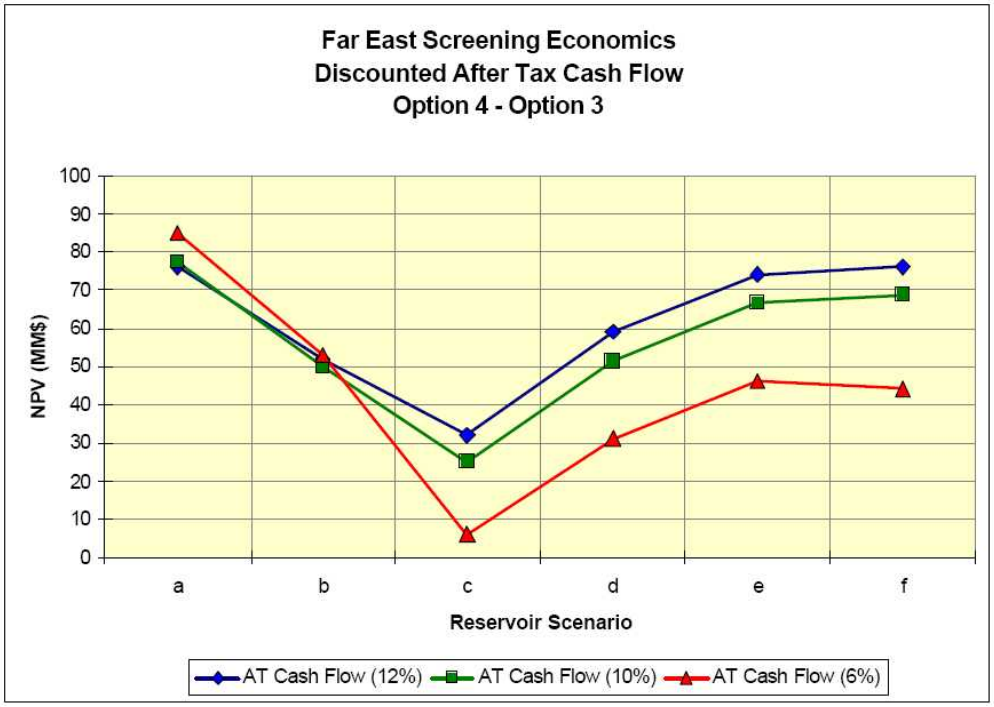


Figure 7: Concept Screening and Economics: Royalties and Tax Difference (Source: After Petro-Canada 2005)

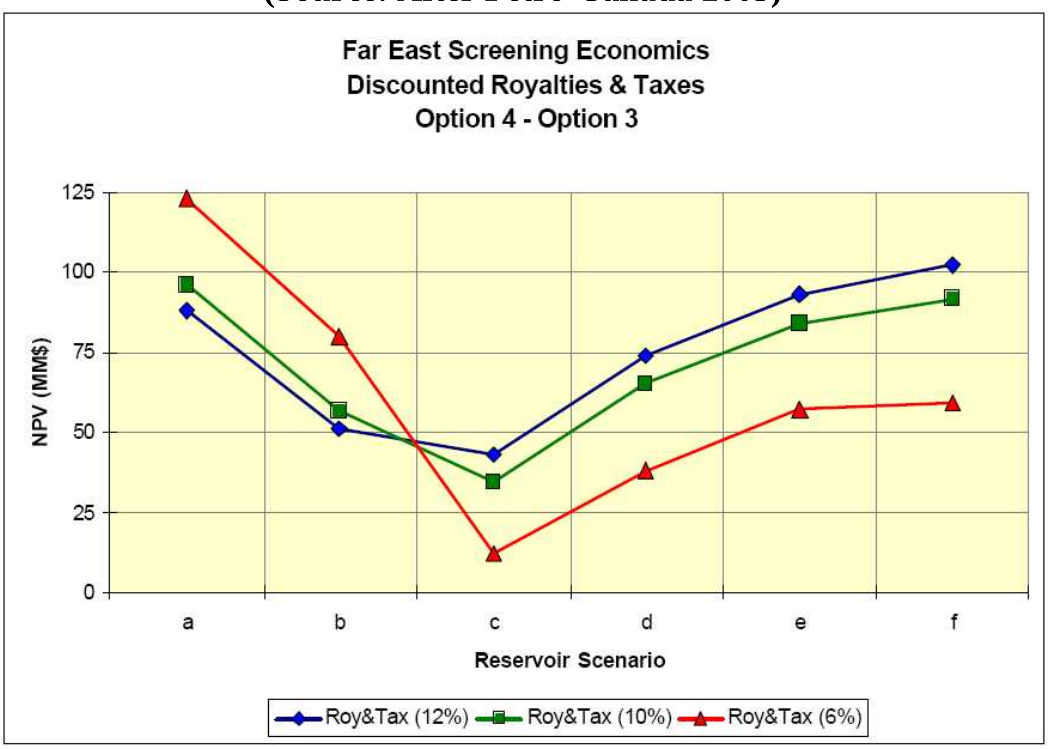


Figure 8: Concept Screening and Economics With Cost Refinement: After Tax Cash Flow Difference (Source: After Petro-Canada 2005)

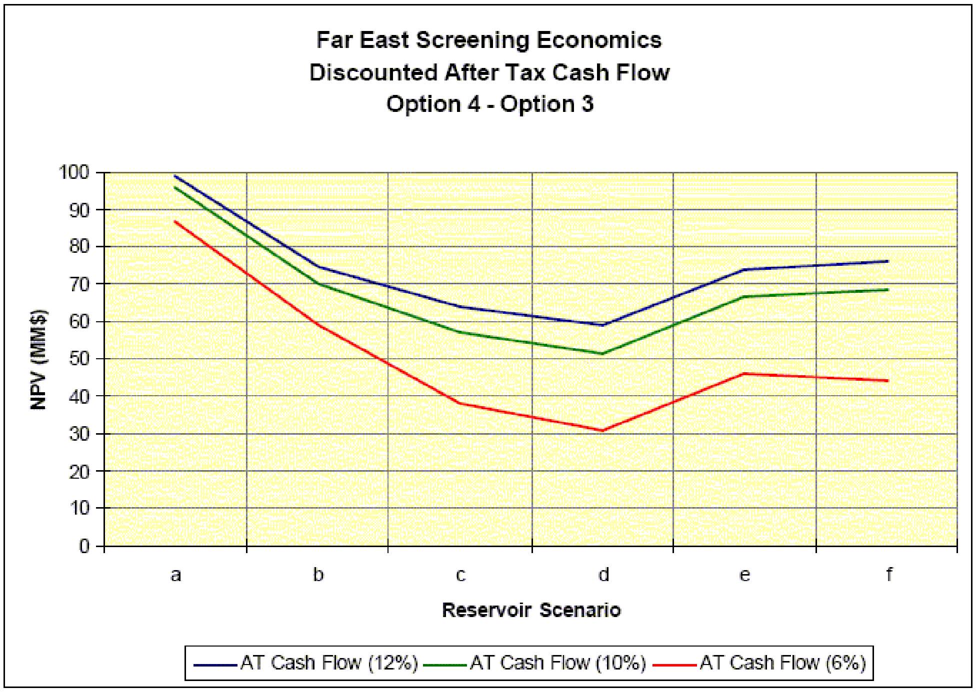
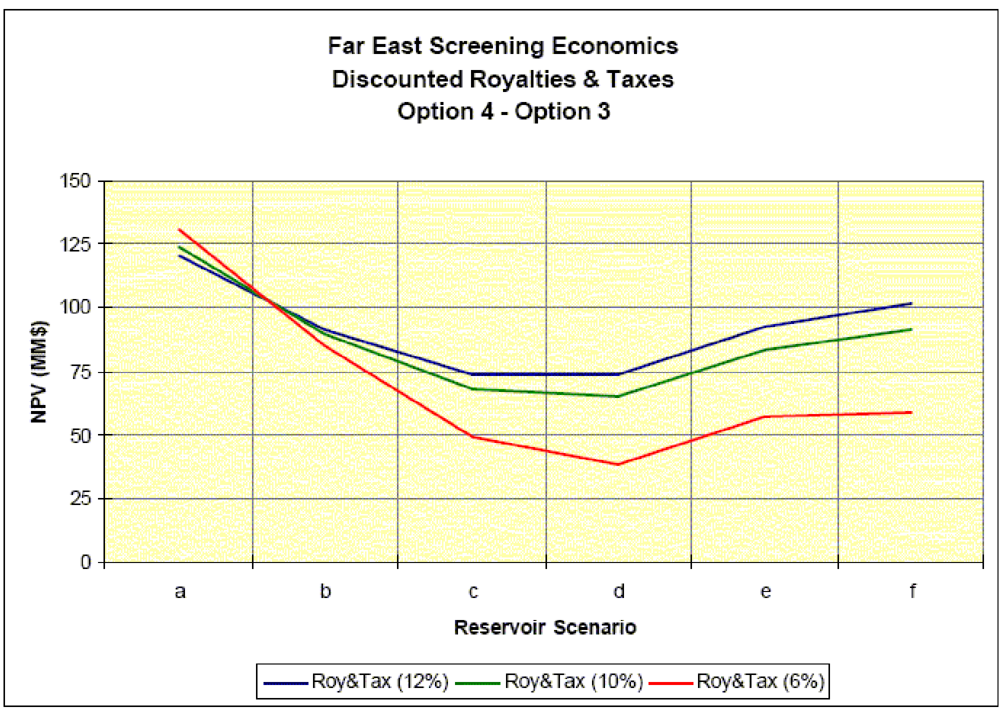


Figure 9: Concept Screening and Economics With Cost Refinement: Royalties and Tax Difference (Source: After Petro-Canada 2005)



2.2.5 Development Strategy

The Proponent is proposing to develop the Far East FEC1 and FEC3 fault blocks through the Northeast and Southeast drill centers, using water injection for pressure support. The solution gas produced from the Far East area will be used to provide additional gas injection support for the Graben C-09 gasflood. According to the Proponent, the Far East Central area will require a producer-injector pair in each of the FEC1 and FEC3 blocks. Figure 10 shows the proposed locations of the Far East area development wells. This will enable Far East production to commence approximately 1-2 years earlier verses a separate subsea development in the Far East.

Pending approval, drilling in the Far East area of the field is scheduled to commence in 2005 with the drilling of the producer-injector pair in the FEC1 block. The production well for the FEC1 block will be drilled from the Northeast drill center and the Southeast drill centre will be used to drill the water injection well into the FEC1 block. The second producer-injector pair of wells for the FEC3 fault block will be drilled as sidetracks from well slots as they become available. The timing of these sidetrack wells is dependent upon slot availability or expansion of existing drill centers. The current base case drilling schedule presented by the Proponent, estimates that these sidetrack wells will be drilled in 2014. Drilling of these sidetrack wells may be accelerated if early production performance and resource assessments result in expansion of the existing drill centers. The tentative drilling schedule for the Terra Nova field, including the Far East, is shown in Table 5.

The Far East wells will be drilled primarily as deviated producers and injectors, which will allow multiple sands to be targeted. The total length for each well is estimated to be approximately 5,000 m MD. According to the Proponent, the wells planned for the Far East will require extended reach drilling technology. To meet the drilling requirements, an up-rated top drive was installed on the Terra Nova field drilling unit in Q1 2005. Modeling conducted by the Proponent indicates that the Far East central locations can be reached with the up-rated top drive. The Proponent states that the experience gained from the Far East central extended reach drilling will allow future expansion of the extended reach drilling envelope, to include additional Far East opportunities. There are however, a number of challenges with extended reach drilling including:

- Torque and drag
- Rate of penetration
- Tortuosity
- Hole cleaning
- Hole stability at higher deviations in the Fortune Bay
- Trajectory design to deliver optimal fault intersections
- Long string casing running and installation

The Proponent notes that these challenges can only be further understood and potentially managed through actual experience in drilling the Far East Central extended reach wells. A horizontal reach of approximately 7 km would be required to capture all of the Far East opportunities from the current East Flank drill centers. The Proponent states that with successful expansion of the extended reach drilling envelope, they should be able to exploit the additional Far East opportunities though efficient use of existing or expanded East Flank drill centers.

Figure 10: Far East Proposed Well Locations (Source: After Petro-Canada 2004)

Table 5: Terra Nova Drilling Schedule (Source: After Petro-Canada 2004)

Terra Nova Base Well Schedule
Full Field Development (Graben+East Flank+Far East)

						Schedule	
Well #	Well Name	Host/ Slot	RMT Common Name	DC	Time (Est)	Start Drilling	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		G1-P	PN1	NE	33	16-Jan-05	18-Feb-05
	Rig Inspection/Upgrade				35	18-Feb-05	25-Mar-05
	compl PN1			NE	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		A2-P	PG7	NW	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		G1-PST	PN2	NE	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

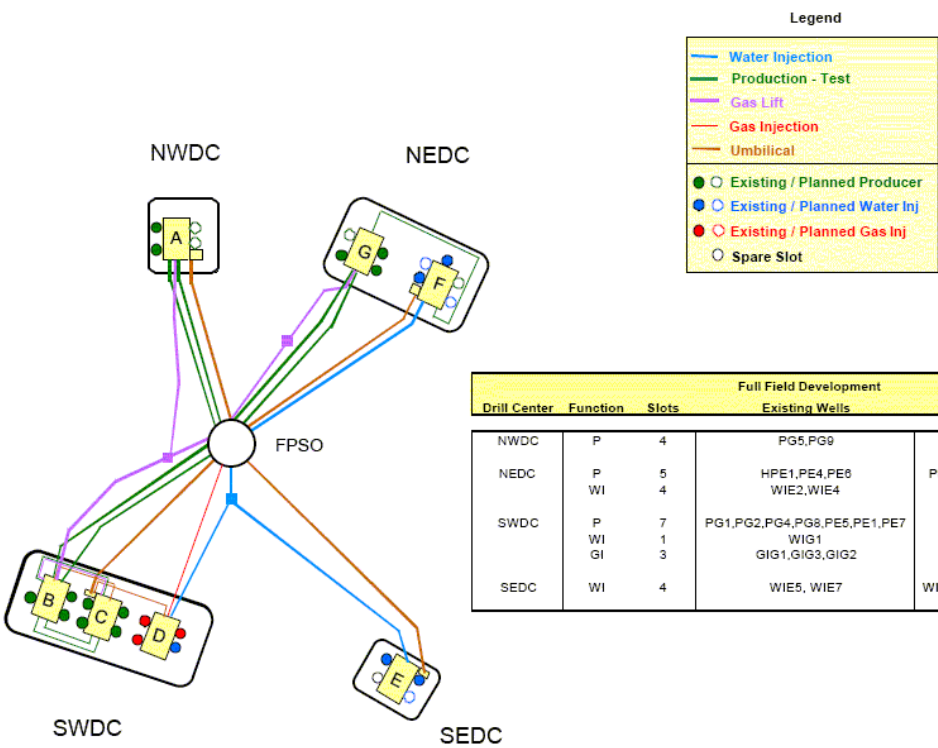
Note: The timing of sidetrack wells (including PF3 and WIF2) is dependent on slot availablity and/or expansion of existing Drill Centers. The results from Far East production performance, ongoing resource assessments (PSDM/RCA/etc) may result in subsea expansion of the existing Drill Centers, resulting in an acceleration of the sidetrack wells.

2.2.6 Drill Centre Expansion Capabilities

The slot utilization at the Terra Nova field, based on the current drilling schedule, is shown in Figure 11. The figure illustrates 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. This represents the number of sidetracks that would be required. However, 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.

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 12. 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 Far East area of the field can be accommodated.

Figure 11: Terra Nova Field Slot Utilization (Source: After Petro-Canada 2004)

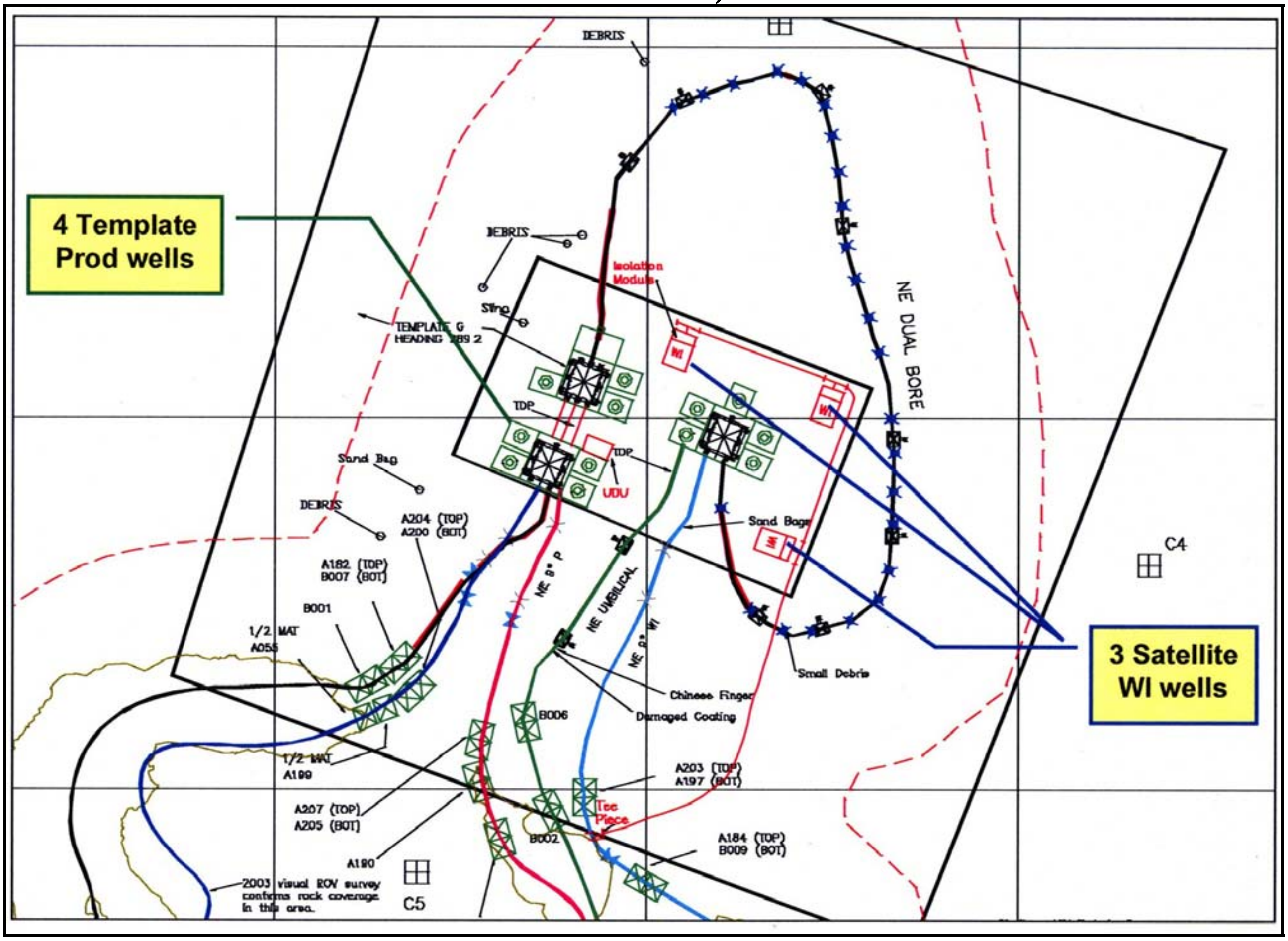


Full Field Development					
Drill Center	Function	Slots	Existing Wells	Planned Wells	Spare
NWDC	P	4	PG5,PG9	PG6,PG7	0
NEDC	P	5	HPE1,PE4,PE6	PE2,PN1,PN2,PF1,PF3	(3)
	WI	4	WIE2,WIE4	WIE8,WIN1,WIN2	(1)
SWDC	P	7	PG1,PG2,PG4,PG8,PE5,PE1,PE7	PE8, PE9	(2)
	WI	1	WIG1		0
	GI	3	GIG1,GIG3,GIG2	GIG4, GIG1ST	(2)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

Figure 4.11: Terra Nova Slot Utilization

PETRO-CANADA

Figure 12: Potential Northeast Drill Center Expansion (Source: After Petro-Canada 2005)



2.2.7 Delineation Strategy

The Proponent notes that of the three wells drilled in the Far East to date, only one has been successful. This highlights the additional uncertainty the Far East carries over the Graben and East Flank. These uncertainties include sand distribution, porosity preservation, oil-water contact, fluid properties, reservoir pressure and temperature conditions and production performance. According to the Proponent, the results of the resource assessment indicate that other opportunities bear considerable risk and should be approached in a step wise manner with the results of the Far East central used to improve understanding and narrow the uncertainty of these opportunities.

The Proponent has developed a Far East delineation strategy to determine how Far East opportunities can be progressed through delineation and possible development. The Proponent's strategy involves reducing the uncertainty and improving the viability of Far East opportunities.

With respect to reducing uncertainty, compartmentalization due to complex faulting is considered one of the key risk factors. The Proponent notes that the impact of this factor on recovery will not be fully understood until long-term production confirms the level of communication in the Far East. The possibility of multiple oil-water contacts is another key risk, which will be assessed by the water injectors planned for the Far East. The Proponent states that the resource assessment will be progressed with the latest reprocessed seismic structural model. This will allow the development of a more inclusive strategy for the remaining Far East blocks.

In order to improve viability of future Far East opportunities, the Proponent installed an up-rated Top Drive on the Terra Nova drilling unit in Q1 2005. This will enable drilling of the Far East central well locations from the East Flank drill centers using extended drilling technology. Lessons learned from Extended Reach Drilling (ERD) should extend the drilling envelope to include additional Far East opportunities, which will enable exploitation of additional Far East opportunities through efficient use of existing or expanded East Flank drill centers. The Proponent also notes that in the event the ERD envelope cannot be extended to include all the Far East blocks, initiatives are currently being evaluated to reduce the subsea development cost for future tie-in opportunities. Areas being investigated include:

- Feasibility of single production flowline tieback (in lieu of dual lines)
- Flowline stability / minimization of rock dumping requirements
- Flow assurance strategies
- Alternate wellhead protection concepts
- Water injection dump flooding

The Proponent has proposed that further delineation drilling in the Far East area be delayed until sufficient production from the FEC1 fault block has been achieved to allow a proper determination of oil recovery in this fault block. The Proponent estimates that this assessment would be possible once the watercut has reached a level between 10% - 50%. According to the Proponent's schedule, it is estimated that a watercut of 10% will be reached after about 1.5 years of production, in July, 2007, and a watercut of 50% will be reached around November, 2007. Figure 13 shows the Proponent's predicted performance of the FEC1 fault block production well, PF1.

Once the projected watercut is reached in the FEC1 fault block, the Proponent will conduct a full field history matching exercise to re-evaluate the remaining Far East opportunities and to identify potential delineation drilling areas. The Proponent states that by the end of 2007, sufficient production and drilling experience should be obtained to allow an assessment of the economic viability of the remaining Far East opportunities. Should the economics prove favorable, the Proponent will then finalize a delineation strategy and select delineation well locations. According to the Proponent's current schedule, this would allow the two Far East delineation wells to be spud before the end of Q2 2008.

In its submission of May 10, 2005, the Proponent has committed to the following:

- A delineation well shall be drilled in the FES “Drill or Relinquish Area” or the FEC2 “Drill Commitment Area” as outlined by the Proponent in Figure 14. Should this well not be spudded by the end of Q2 2008, the Proponent will relinquish the lands within this FES “Drill or Relinquish Area”;

- A delineation well shall be drilled within the FEN3, FEE or the Terrace areas. Should this well not be spudded by the end of Q2 2008, the Proponent will relinquish the lands within the FEN3 fault block.

Figure 13: Far East PF1 Predicted Production Performance (Source: After Petro-Canada 2005)

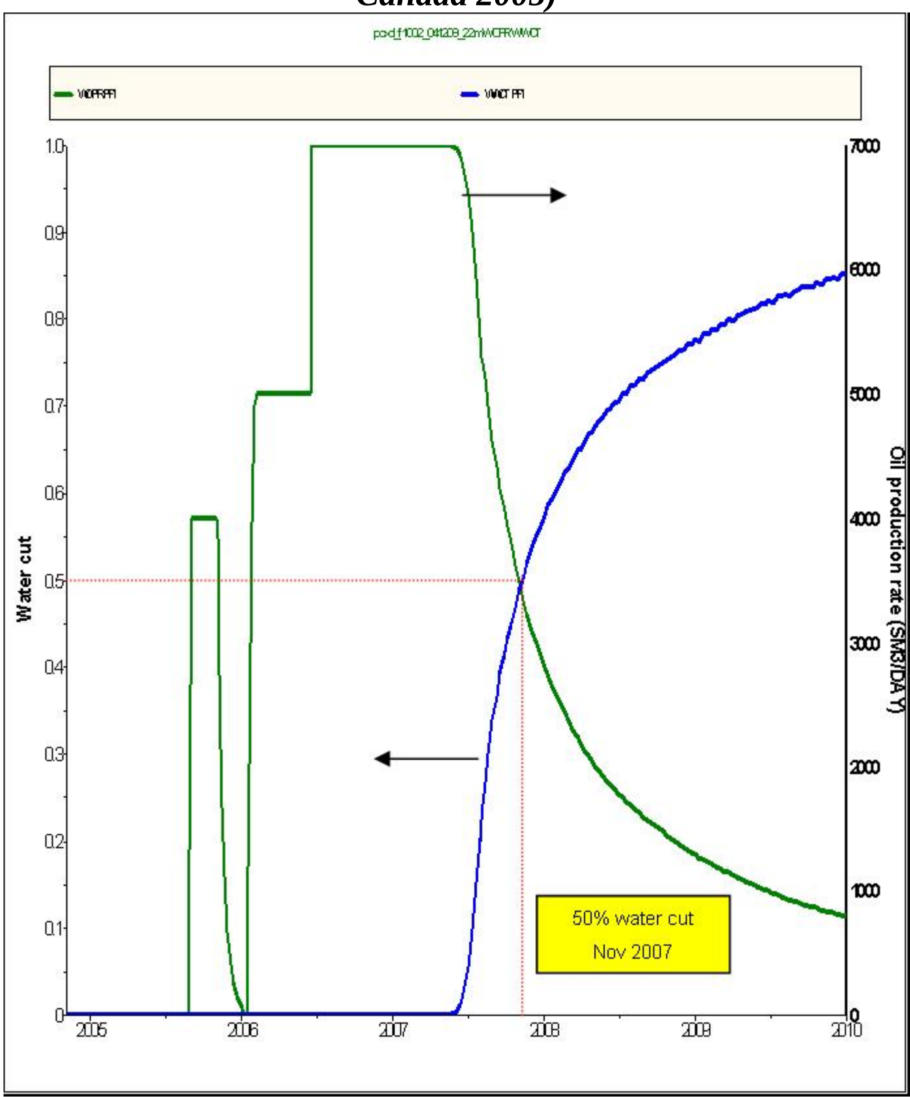
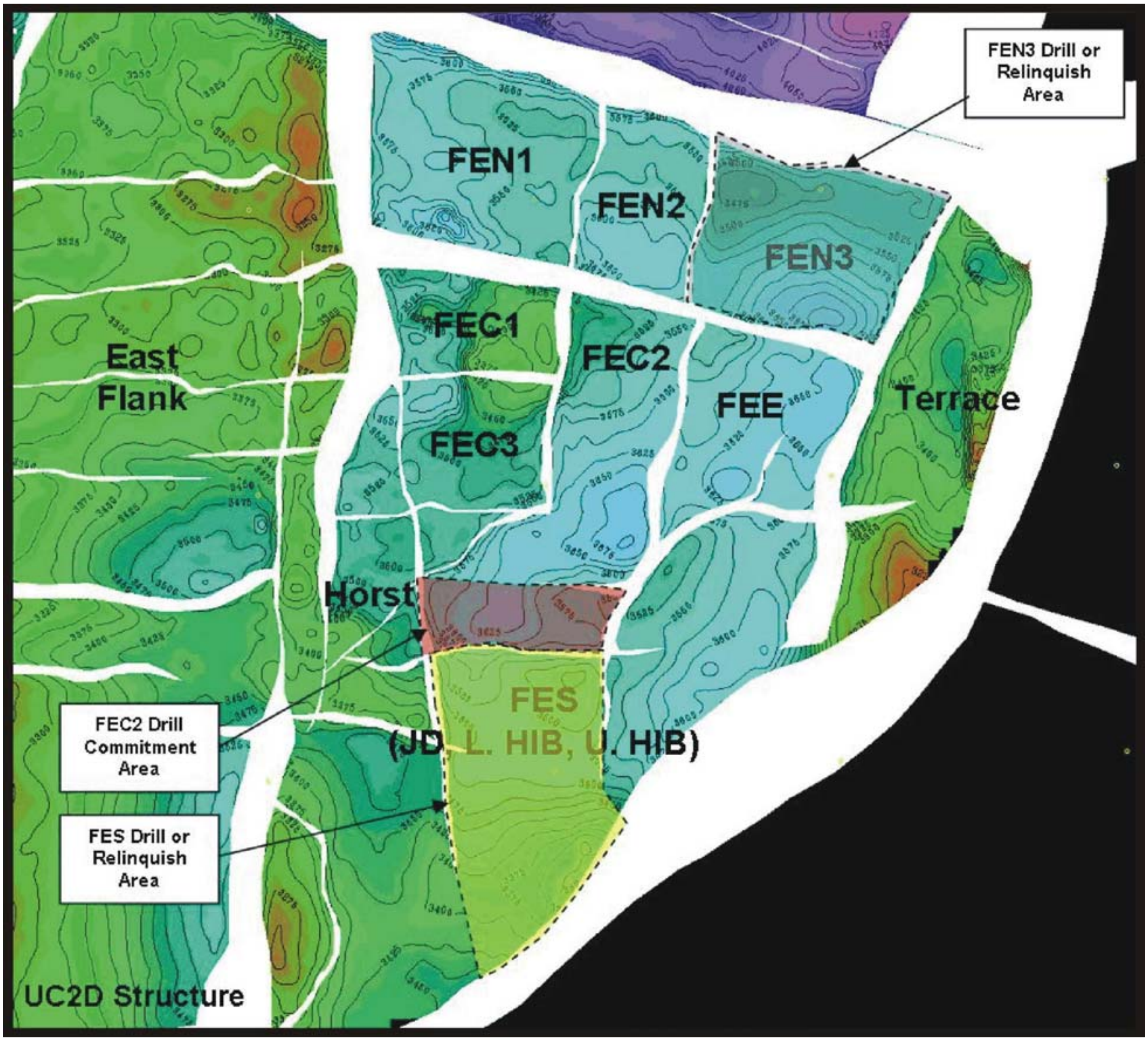


Figure 14: Far East Commitment Blocks (Source: After Petro-Canada 2005)



2.2.8 Reservoir Simulation Model and Production Forecast

The Proponent has constructed a full field reservoir simulation model to continue planning and optimization of the Graben and East Flank areas and to evaluation the Far East development strategy. The simulation model is based on the 2003A geological model which has been updated to include all wells up to C-69 3. The simulation model has been history matched to production data to the end of June, 2004.

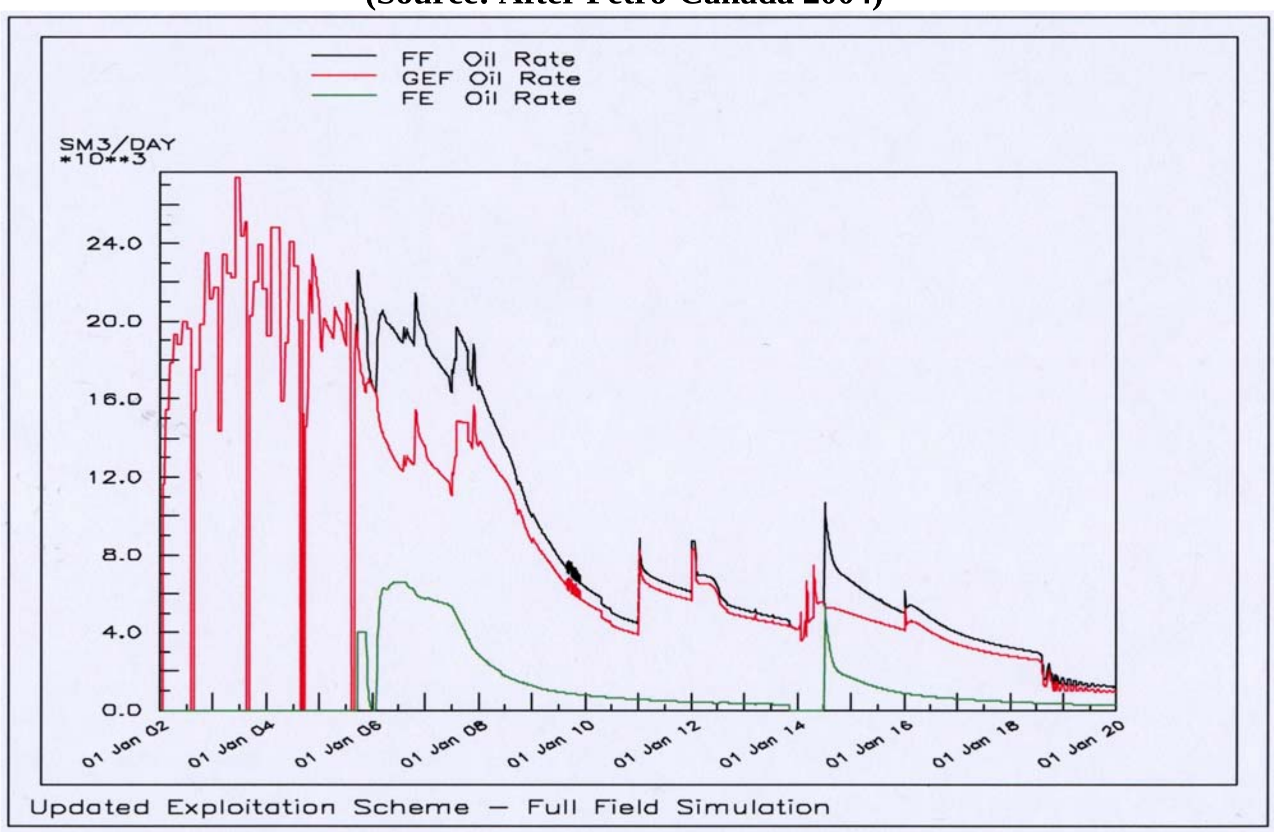
The model consists of 150 by 110 grids with 57 layers for a total of 940,500 cells. Three PVT regions have been defined including the Graben / North Graben, East Flank and Far

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. The Far East area has an inferred oil-water-contact of -3,473 mss based on the intersection of the C-69 1 oil gradient and the C-69 3 water gradient. Drilling results to date have not identified a gas-oil-contact in the Far East area of the field.

Pending approval, production from the Far East is scheduled to begin in Q3 2005 with the first production well in the FEC1 block. When the first Far East production well starts production in 2005, an immediate increase in production is observed. The production drops off slightly until the supporting water injection well is brought on stream. Without the contribution of the Far East production, there would be a significant drop in the production profile in 2006. The production profile shows a jump in the production in 2005 from 16,000 m^3/d to 20,000 m^3/d when production commences from the Far East area.

The second production well in the Far East in the FEC3 fault block will begin production in 2014. A small increase in production is also observed in 2014 when production from this well commences. The full field production forecast including the base case for the Far East development is shown in Figure 15.

Figure 15: Terra Nova Production Forecast including the Far East (Source: After Petro-Canada 2004)



2.3 Board's Review

The Board's technical staff have reviewed the "***Updated (2004) Exploitation Scheme for the Far East Area of the Terra Nova Field***" submitted in December, 2004, the documents "***Updated (2004) Exploitation Scheme for the Far East Area of the Terra Nova Field Addendum***" and "***Terra Nova Far East Concept Screening (2004)***" submitted on January 21, 2005 and the document "***Updated (2004) Exploitation Scheme for the Far East Area of the Terra Nova Field Addendum 2***" submitted May 10, 2005. The Board's technical 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 December 31, 2004, twenty-six development wells have been drilled in and 20.3 million m^3 (127.5 million barrels) of oil have been produced from the Terra Nova field, which has provided a substantial quantity of new information to assess reservoir and facility performance and construct geological and reservoir simulation models. The staff 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 are differences between the geological model carried by the Board and that of the Proponent. 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.

Both the Board's technical staff and the Proponent have analyzed the open hole logs and wireline pressure data acquired from wells drilled in the field. Pressure data collected in the Far East area of the field suggests a common fluid system. The water gradient at the C-69 3 well and the oil gradient at the C-69 1 well resulted in a projected oil-water-contact of -3,473 mss.

2.3.2 Oil-in-Place and Reserve Estimates

The Board's technical staff have also conducted an assessment of the oil-in-place for the Far East area of the field presented by the Proponent and the resource estimates based on the Board's geological model. A comparison of the Proponent's and the Board's volumetric oil-in-place estimates by sand, for the Jeanne d'Arc reservoirs in the Far East area is shown in Table. 6. The Board's technical staff also estimate a further 2.01 million Sm^3 (13 million barrels) of oil-in-place in the Jeanne d'Arc reservoir in the Far East south area. Staff acknowledges the potential oil resources noted by the Proponent in the Upper and Lower Hibernia Formation reservoirs in the Far East south and in the Jeanne d'Arc Formation reservoir in the Terrace block located on the eastern edge of the field. The Board's technical staff considers these reservoirs to be prospects, and they are not included as part of the commercial discovery oil accumulation.

The Board's technical staff conducted a reserve assessment of the Far East 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 Board assigned no proven reserves, but assigned probable reserves to the Far East area of 7.08 million Sm^3 (44.5 million barrels). The Board's technical staff have assigned possible reserves to the southern region of the Far East area. The staff estimate the upside reserves (i.e. the proven plus probable plus possible reserves) in the Jeanne d'Arc reservoirs to be 13.03 million Sm^3 (82 million barrels). Table 7 shows a comparison of the C-NLOPB's probable and the Proponent's unrisked (P50) reserve estimates. The reserve estimates are in close agreement in the Far East central area that is proposed for development. At this time, the Board does not carry any P50 reserves in the Far East area of the field outside of the Far East Central and Horst regions.

Table 6: Comparison of C-NLOPB's and Proponent's Volumetric Original Oil-in-place Estimates

Fault Block	E Sand		D Sand		C Sand		Total	
	C-NOPB	Proponent	C-NOPB	Proponent	C-NOPB	Proponent	C-NOPB	Proponent
FEC1	1.384	1.26	6.081	8.37	4.445	2.07	11.91	11.70
FEC2 & FEC4	0.215	0.10	2.207	0.74	0.298	0.00	2.72	0.84
FEC3	0.512	0.06	3.631	2.59	0.631	0.34	4.77	2.99
FEN1	0.747	2.28	0.058	4.20	0.091	0.00	0.90	6.48
FEN2	0.000	1.67	0.000	0.24	0.000	0.00	0.00	1.91
FEN3	0.000	1.62	0.000	0.62	0.000		0.00	2.24
FEE	0.002	0.00	0.000	0.00	0.000	0.00	0.00	0.00
Horst	0.380		7.330		1.870		9.58	2.25
Total (million Sm^3) **Total (million barrels)**	**3.24** **20.38**	**6.99** **43.97**	**19.31** **121.43**	**16.76** **105.42**	**7.34** **46.14**	**2.41** **15.16**	**29.88** **187.95**	**28.41** **178.69**

Table 7: Comparison of C-NLOPB's Probable and Proponent's P50 Reserves

Far East Fault Block	P50 Reserve Estimates (million m^3)	
	C-NOPB	Proponent (Figure 3-8)
FEC	5.00	6.90
Horst	2.08	1.40
Terrace		8.50
FEN1		2.00
FEN2		0.10
FEN3		0.80
FEE		1.10
FES JDA		4.40
FES UHIB		3.30
FES LHIB		1.80
Total (million Sm3):	**7.08**	**30.30**
Total (million barrels):	**44.53**	**190.58**

2.3.3 Reservoir Simulation Model Review

The Board's technical staff reviewed the data and assumptions used to construct the Proponent's reservoir simulation model and believe that they are reasonable. The staff notes that in the simulation model, Far East production accounts for 30% of the total production in 2006.

2.3.4 Development Strategy

The Board's technical staff agree with the Proponent's proposal to use water injection to deplete the oil reserves in the Far East region. This approach is working well in the East Flank area of the field. The technical staff of the Board reviewed the concept screening study provided by the Proponent and concur that from an economic perspective, the proposed approach of developing the Far East FEC1 and FEC3 fault blocks through the Northeast and Southeast drill centers is the best solution. However with no commitment to install a Far East drill centre, this approach is putting at risk development of further reserves in the Far East area.

According to both the Board's technical staff and the Proponent's analysis, there are sufficient reserves in the Far East FEC1 and FEC3 fault blocks to justify a drill center. If the Proponent's proposed strategy is approved, the reserves in the Far East FEC1, FEC3 and potentially the FEN1, FEN2 and FEN3 fault blocks would be depleted from the Northeast drill center thus committing the remaining drill slots and production facilities to development of these fault blocks. If other potential reserves are to be exploited in a timely manner, they must be of sufficient quantity to justify the installation of a drill center in the Far East glory hole or installation of other facilities.

The Far East south region has the best potential for additional reserves. According to the Proponent the Far East south opportunity is economic on a stand-alone basis if it has reserves greater than 5.6 million Sm^3 (35 million barrels). It would be uneconomic on a stand-alone basis with reserves less than 4 million Sm^3 (25 million barrels). The un-risked P50 reserves, estimated by the Proponent, for this area are 9.5 million Sm^3 (60 million barrels) while the risked reserves are estimated to range from 3.3 to 7.2 million Sm^3 (21 to 45 million barrels).

With the proposed approach to Far East development, the Proponent has provided for the possible installation of a Far East drill center. However, the Proponent has put at risk a significant volume of reserves, up to 4 million Sm^3 (25 million barrels), that may not be exploited in the future. Also, without a Far East drill center, the Far East development, in conjunction with North Graben development, will use the remaining six drill slots; eliminating flexibility to take advantage of development opportunities or deal with problems with the exploitation scheme in a timely manner should they arise. This would not be the case if a drill center is located in the Far East glory hole to develop the existing reserves.

A Far East drill center would:

1. reduce the threshold reserves for economic development of other Far East opportunities,
2. provide additional drilling slots to access potential reserves in the area and other regions of the field,
3. accelerate production from other regions of the Terra Nova field, and
4. reduce the need for extended reach drilling, which to date has been a problem in developing the Terra Nova field Jeanne d'Arc reservoir.

Although the Proponent estimates that there is greater than a 90% probability that the Far East south opportunity can be incorporated in the development strategy proposed, the Proponent notes this is not to say that there is a 90% probability that there is sufficient reserves in the Far East south to justify a drill centre. According to the information provided by the Proponent, the Board's technical staff notes that 35 percent of the outcomes considered were unsuccessful, 33 percent of the possible outcomes would be considered economic, and up to 32 percent of the outcomes may not justify development. The Proponent is not willing to commit to installation of a Far East drill center without further delineation drilling to confirm the likely reserve potential, which is prudent given the uncertainty surrounding the estimated volumes. The technical staff of the Board notes the Proponent's view that the recommended development strategy for the Far East central block is not dependent on delineation drilling in the Far East south.

2.3.5 Discussion

In Decision 97.02, approving the Terra Nova field Benefits and Development Plan, the Board noted that resolution of uncertainties affecting the geological and geophysical interpretations may change the proposed well locations and estimated number of wells required to deplete the oil reserves, particularly in the Far East. The Board also acknowledged the Proponent's stated intention to acquire the necessary information early in the life of the field. However, at that time the Board observed that "it is likely that more than one well will be required to acquire sufficient information to adequately support a comprehensive development plan for the Far East region".

In the document "***Reservoir Basis for Terra Nova Development***" submitted to the Board in March, 1998, the Proponent indicated plans to drill three delineation wells in the Far East area of the field. Figure 16 shows the location of these three delineation wells as presented by the Proponent. The Board's technical staff note that the Proponent has prepared a glory hole in the Far East area and drilled three development wells , one of which was drilled shortly after the initiation of production at the field.. Only one of these development wells, PF2, has been drilled at a location consistent with the proposed delineation wells in the reservoir basis for Terra Nova Development.

It is the view of the Board's technical staff that if the three stand-alone delineation wells proposed for the southern and northern areas of the Far East had been drilled, information necessary to support a comprehensive development plan for the Far East region would have been acquired. In essence, the approach taken by the Proponent to delay delineation drilling has likely led to unnecessary capital expenditures that have burdened the project. Despite the three wells drilled to date, the Far East area is still not adequately delineated. Also, with the approach taken, the development wells are not ideally located and may not be of use in any future development. Further, if a drill center is not installed in the Far East glory hole, this capital expenditure will have been unnecessary. Not including the cost of the glory hole, this amounts to about $83 million in drilling expenditures.

The Board believes that if resources are to be exploited to their full potential, it is important that information, particularly from delineation wells, be acquired early to provide for proper planning and exploitation of the resources within the life cycle of the production facilities. The Board considered the Proponent's proposed strategy for delineation drilling and the commitment to drill or relinquish selected areas shown in Figure 14. The Board concurs with the Proponent's proposal to drill or relinquish in the FEN3 area. However, in respect of the FES and FEC2 areas, the Board's technical staff concluded that there is a low chance of encountering hydrocarbons in the FEC2 fault block and believes that the southern delineation well should target the FES area only, and not the FEC2 area proposed by the Proponent. The Board does not accept the Proponent's proposed drill or relinquishment plan for the Far East south. According to information presented by the Proponent, the Far East south has the greatest chance of encountering additional oil reserves in the Far East area. The economic analysis presented by the Proponent, in support of the alternate exploitation schemes, provided for a well to be drilled prior to 2008. The Board believes that a delineation well is necessary to resolve the technical uncertainty in the Far East southern area and this well should be drilled earlier than 2008.

If lands are relinquished in the Far East north area, staff of the Board note that the land boundaries should be determined in accordance with the Board's land issuance practices and the result would be different from the lands outlined in the Application. In determining the boundary of lands to be relinquished, the Board's technical staff would like to be able to consider information available at that time. If this were to be the case, the boundaries of the relinquished lands may be slightly different from those proposed by the Proponent. Whether delineation wells are drilled or not, the Board will, in the normal performance of its duties, assess the Commercial Discovery Area to determine if lands should be added or removed from the Terra Nova Commercial Discovery Area.

The Proponent has acknowledged that the break-even reserve size for the Far East South required to offset the added value from proceeding with Option 4 is approximately 4.0 million Sm^3 (25 million barrels). In essence, the Board is being requested to approve an option that could lead to lost reserves of between 4 million Sm^3 (25 million barrels) and 5.6 million Sm^3 (35 million barrels). Section 29 (1) of the Newfoundland Offshore Area Petroleum Production and Conservation Regulations states "***An operator shall provide for maximum recovery of oil and gas from a pool or field***". Given that both options are economic, albeit according to the Proponent the proposed option is projected to result in substantial economic value to both the Proponent and the government, the legislation requires that the option, which maximizes oil recovery should be employed. However, in considering "waste", a reduction in the quantity of petroleum that could be ultimately recovered, Section 154 of the Act, which addresses waste, makes reference to "having regard to sound engineering and economic principles".

The Board's technical staff have reviewed the economic analysis conducted by the Proponent and also conducted an independent economic analysis. According to the Proponent, the after tax value for the Terra Nova owners for proceeding with Option 4 over Option 3 for all reservoir scenarios is estimated to range from $30 to $100 million, while the royalties and taxes are estimated to range from $40 to $130 million. This difference is also evident in the graphs presented in Figures 6 and 7. A summary of the Proponent's economic analysis is provided in Table 8, which shows the difference in after tax cash flow and royalties and taxes for proceeding with Option 4 over Option 3 for reservoir scenarios 'a' and 'c'. The range shown in the table is representative of the various discount rates used by the Proponent. The Board's technical staff concur with the Proponent's analysis that there may be a substantial economic benefit to all stakeholders by proceeding with Option 4.

Figure 16: Far East Proposed Delineation Wells from Reservoir Basis for Terra Nova Development (Source: Petro-Canada 1998)

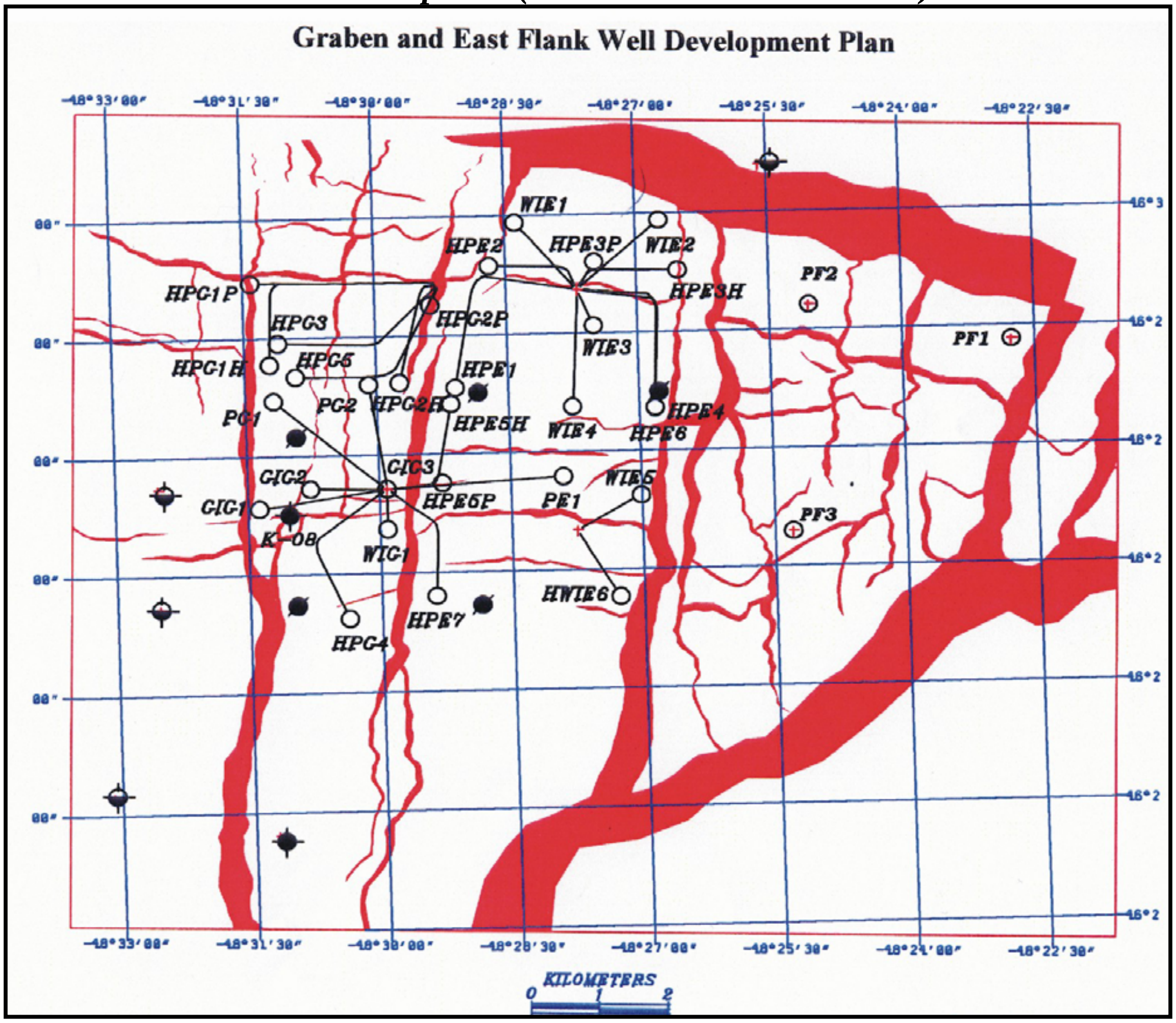


Table 8: Discounted After Tax Cash Flow & Royalties and Taxes: Difference between Option 4 & Option 3

	Discounted After tax Cash flow to Proponent	Royalties & Taxes to Governments
Option 4c - Option 3c	\$38 - \$64	\$49 - \$74
Option 4a - Option 3a	\$57 - \$99	\$121 - \$131

In assessing the proposed exploitation scheme there are many considerations. These include:

- Option 4 allows production to begin earlier, improving the economic benefit, and reducing the economic risk if the reserves prove to be lower than expected.
- Proceeding with Option 4 may lead to a reduction in reserves; however, there is an equal chance that sufficient reserves will be identified to support installation of a drill center in the Far East.
- Improvements in drilling capabilities and production technology could reduce the risk of stranding reserves. The Proponent has already made a significant investment to improve the extended reach capability of the Terra Nova drilling unit. However, even with the improved extended reach capability, it is still not possible to reach the Far East south area from the North East drill center.
- While the legislation requires that an operator provide for maximum recovery of oil and gas from a pool, it also requires that the Board have regard for sound economic principles.
- Using sound economic principles Option 4 is the preferred choice since in most cases it has substantive economic benefit to the Proponent and governments; particularly if the reserves are lower than anticipated.
- As there are limited production facilities and they have a limited life, it is important that the Terra Nova field be fully delineated in a timely manner to allow for proper planning.

The Board considered requiring a delineation well to be drilled prior to making a decision (i.e. the Board require a well prior to allowing the Proponent to proceed with Option 4). However according to the Proponent, a delineation well in the Far East south will take about 65 days to drill and cost $30.4 million. In addition, several months would be required to plan and acquire the high strength casing required to drill the well. The delay in production caused by implementing this option could reduce after tax cash flow to the Proponent by $19 to $28 million and royalties and taxes to the governments by $61 to $67 million. The Board's technical staff conducted its own economic analysis and concur with the Proponent's estimates.

The Board considered all factors, including the technical issues and waste provisions of the legislation, and concluded that given the substantial economic benefits to all stakeholder and the technical risks, it is prudent to proceed with Option 4. Also the Board notes, according to the information provided by the Proponent that the Southern area of the Far East has the best chance of encountering significant oil reserves. The Board believes that a delineation well is required in the Southern area of the Far East, earlier than proposed by the Proponent, to resolve the technical uncertainties and acquire the necessary information to assess the development potential of this area.

The Board has therefore approved the following:

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.

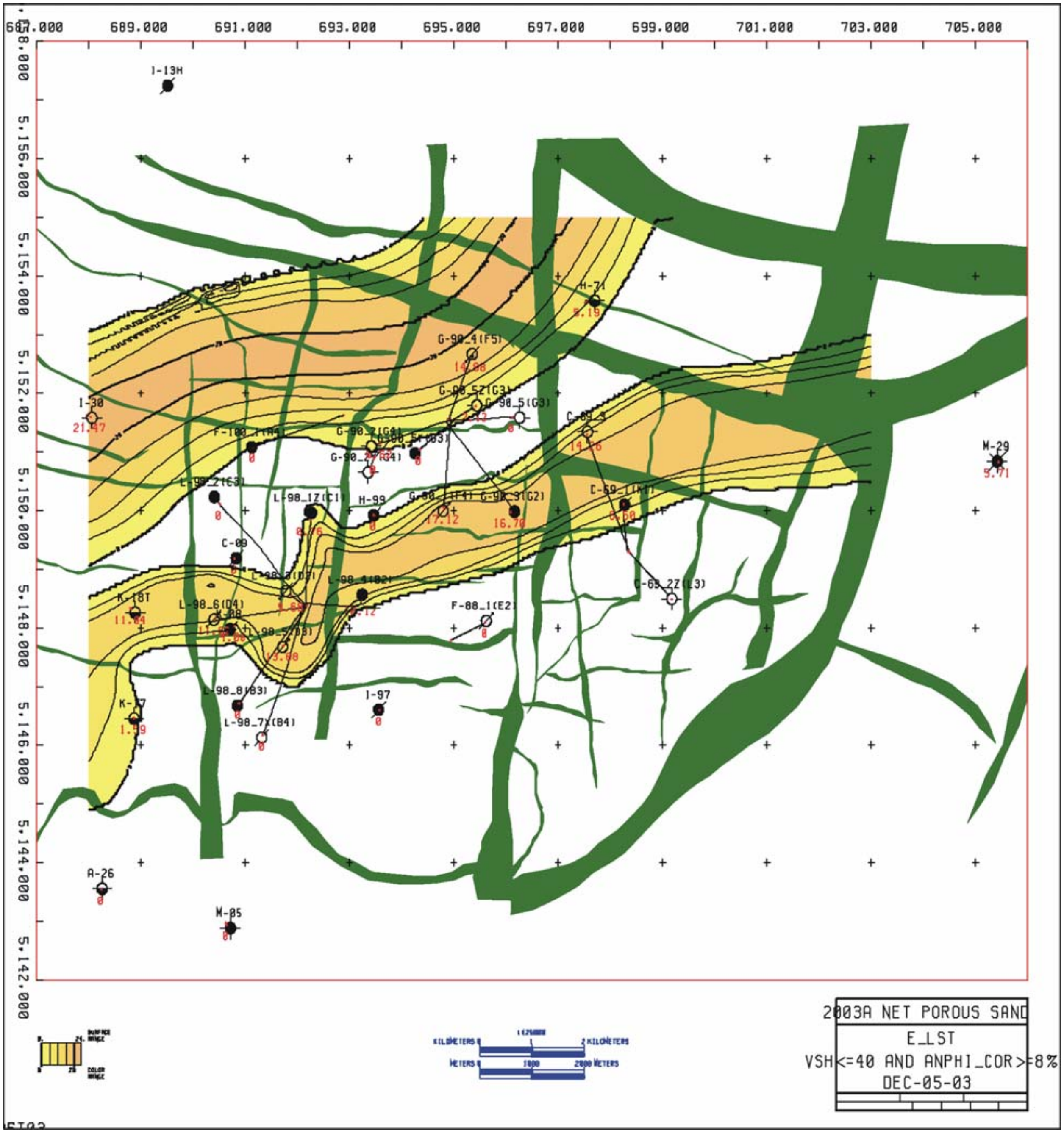
Condition 2005.01.01
A delineation well be commenced by December 31, 2008 in the FEN3 area or the land relinquished as proposed the Proponent.

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.

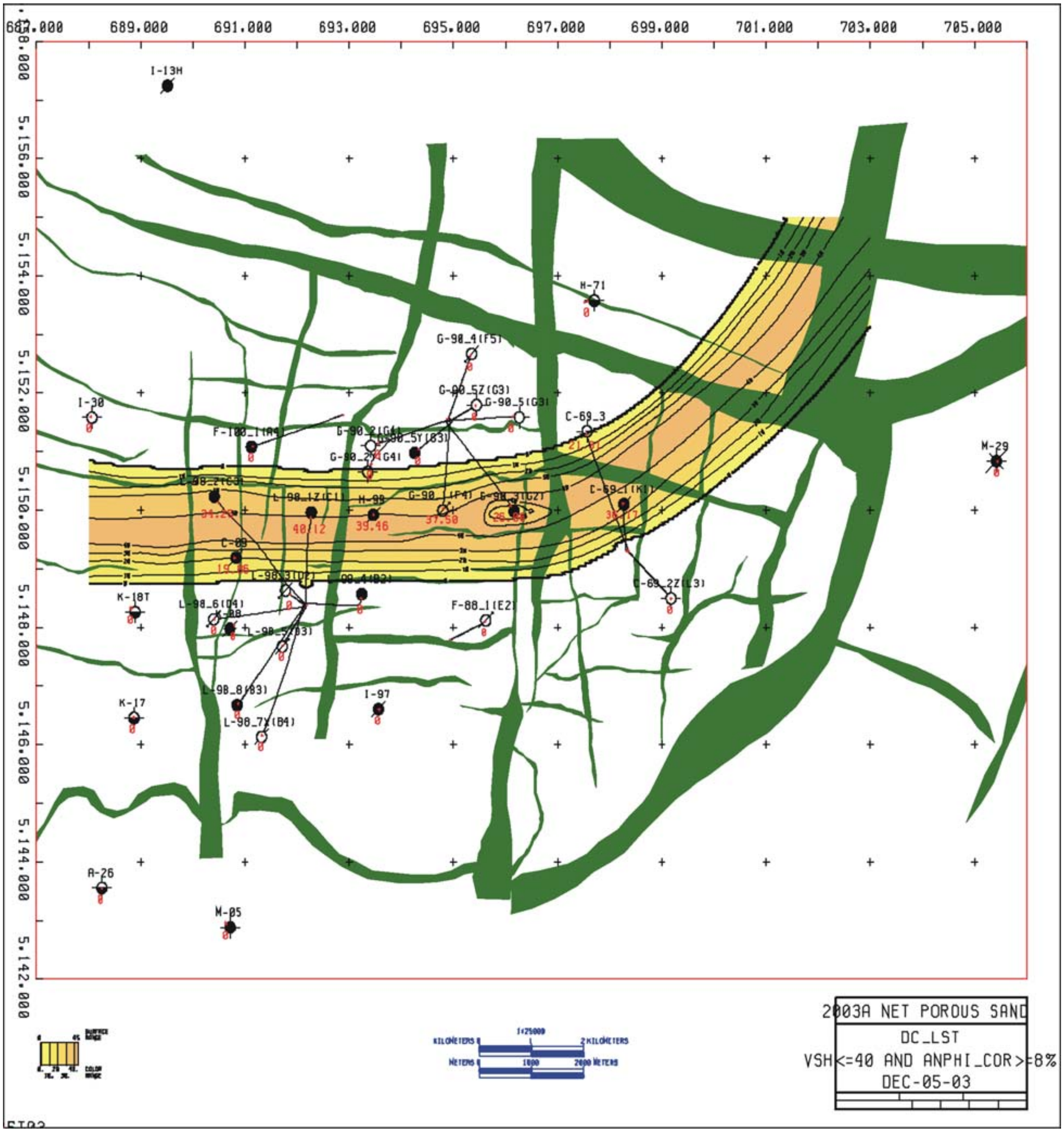
Condition 2005.01.03
Within three months of termination of the well in the FES fault block, the Proponent submit a report of the results of the well and an assessment of the development potential of any oil resources encountered.

Appendix A

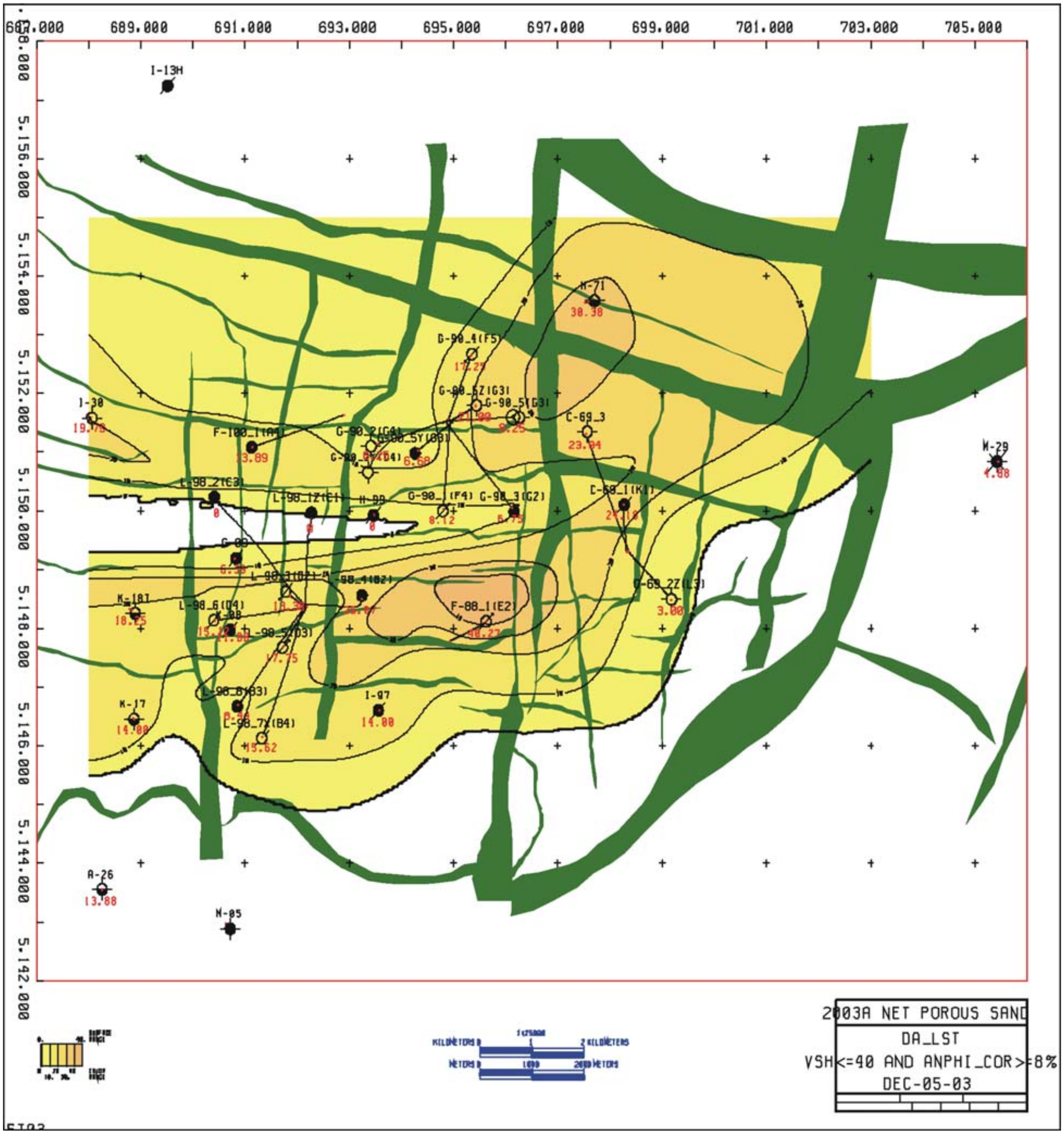
Proponent's Isochores



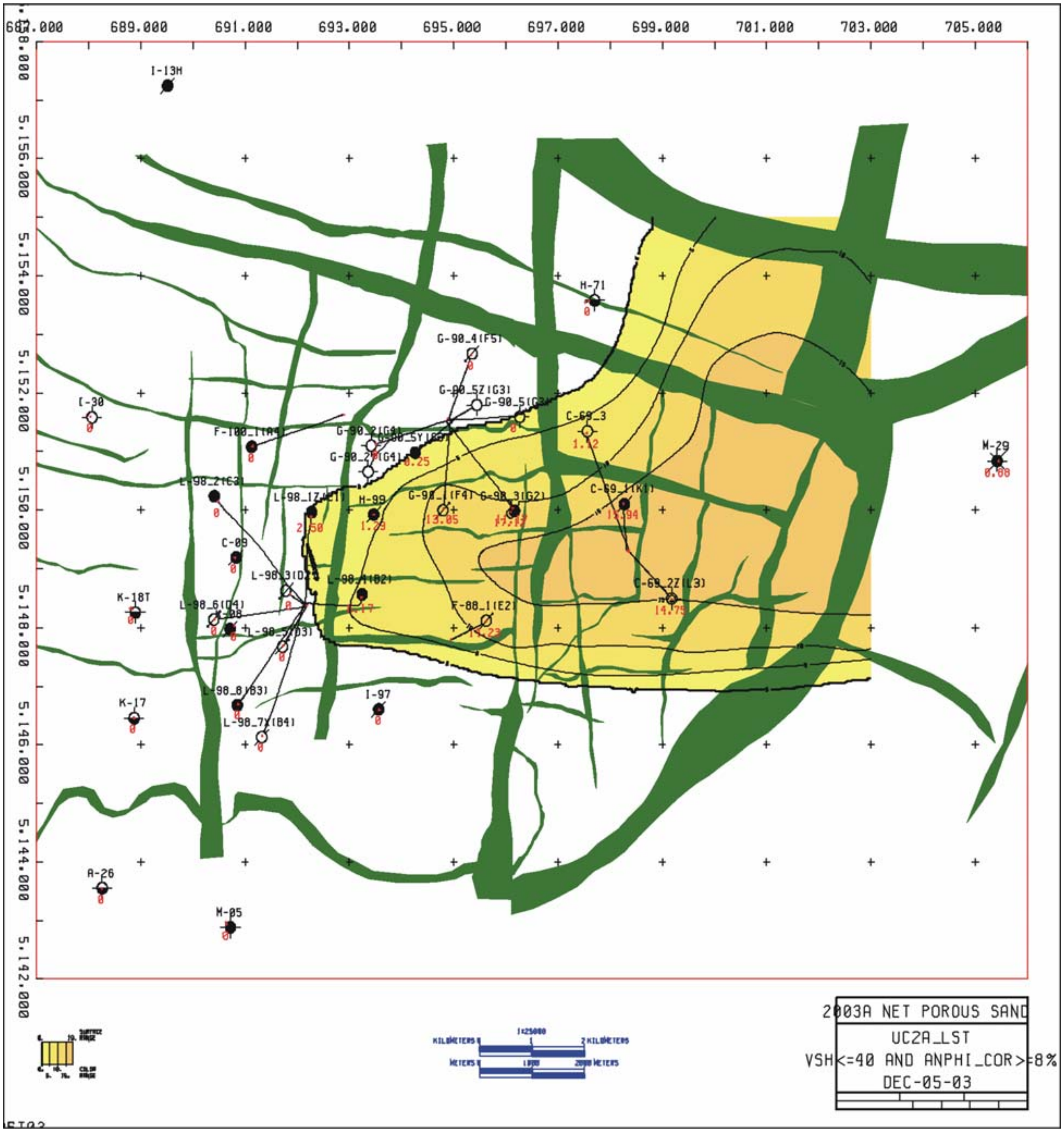
Proponent's E sand Isochore



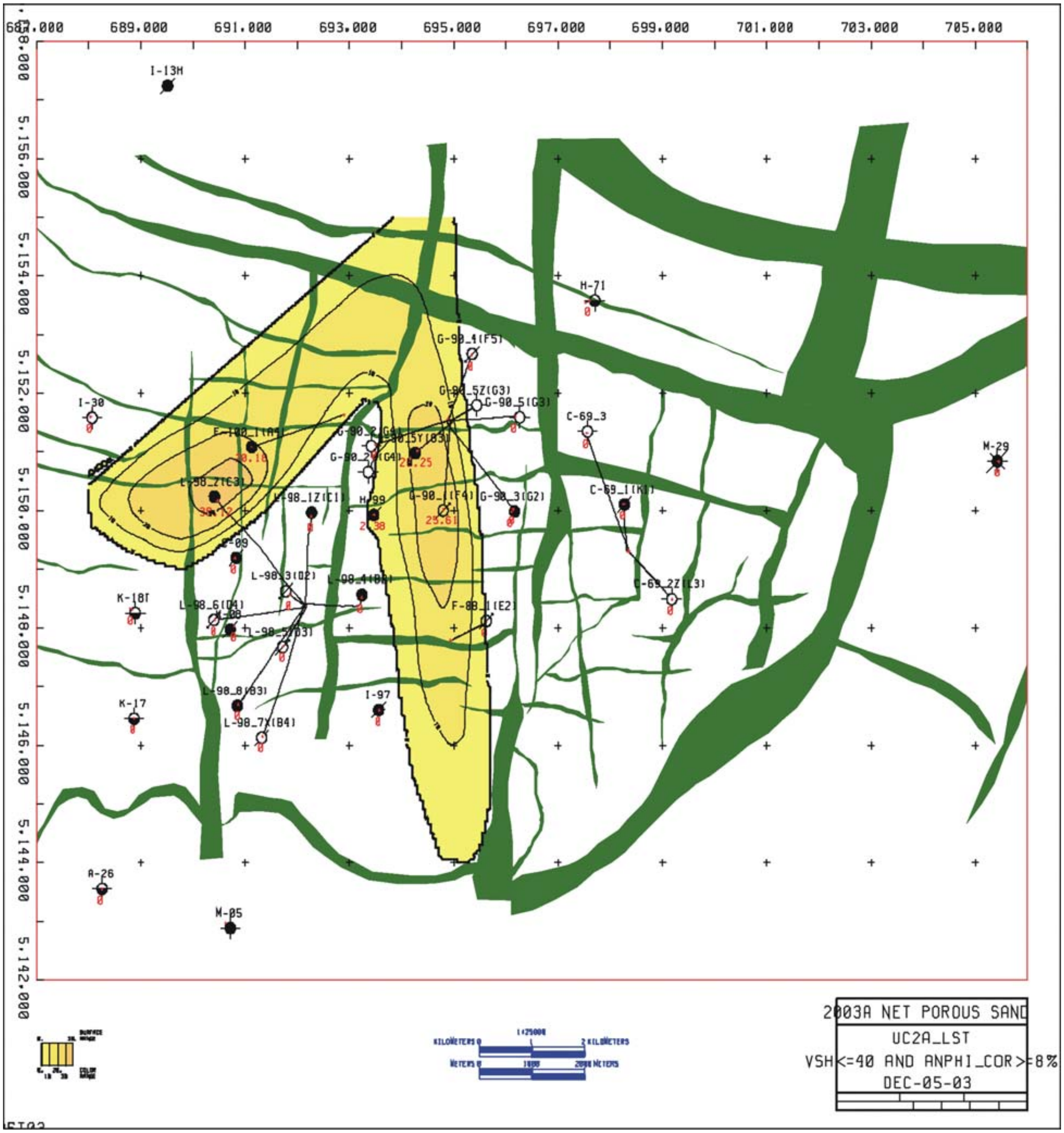
Proponent's DC sand Isochore



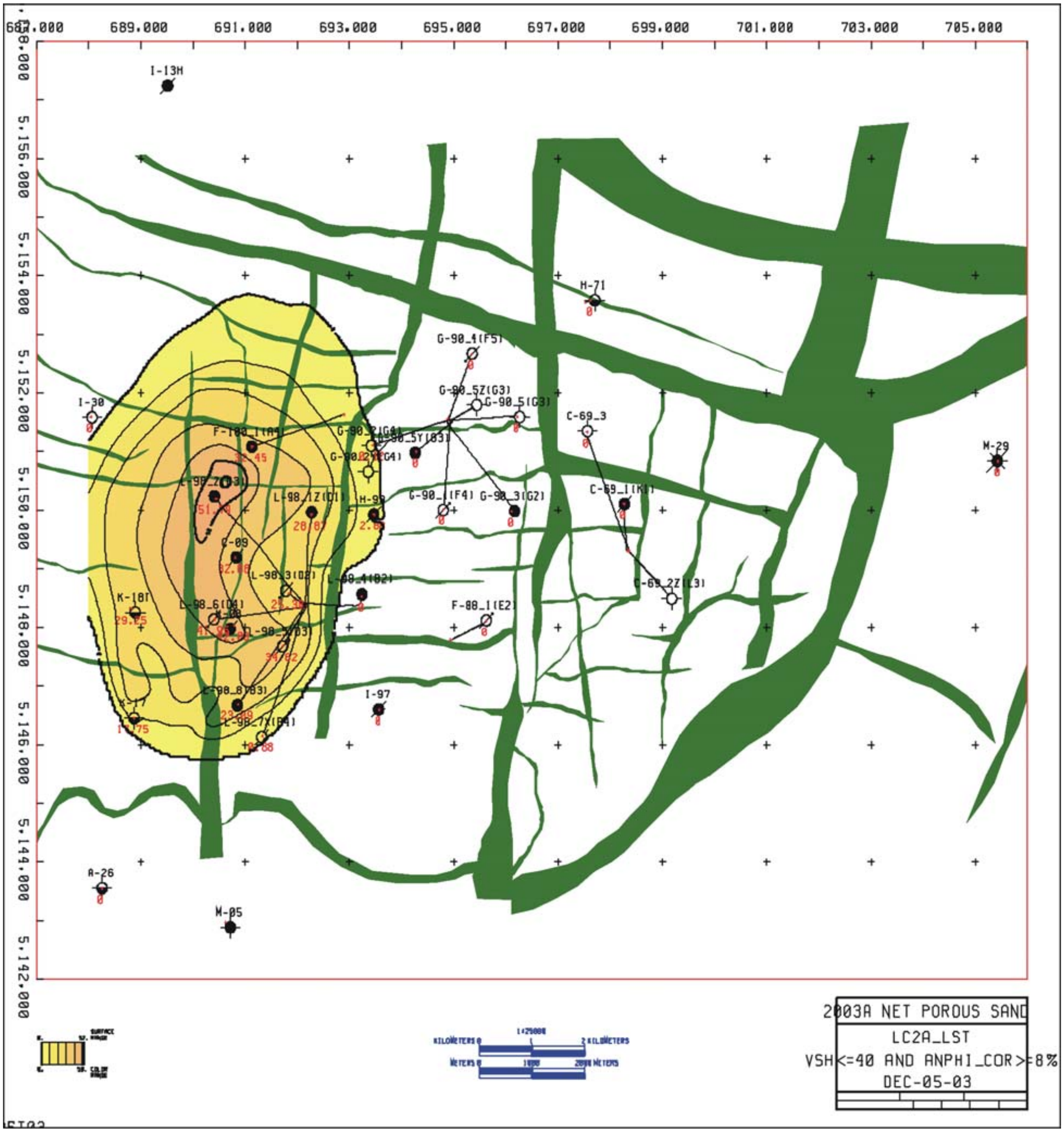
Proponent's DA sand Isochore



Proponent's UC2C sand Isochore



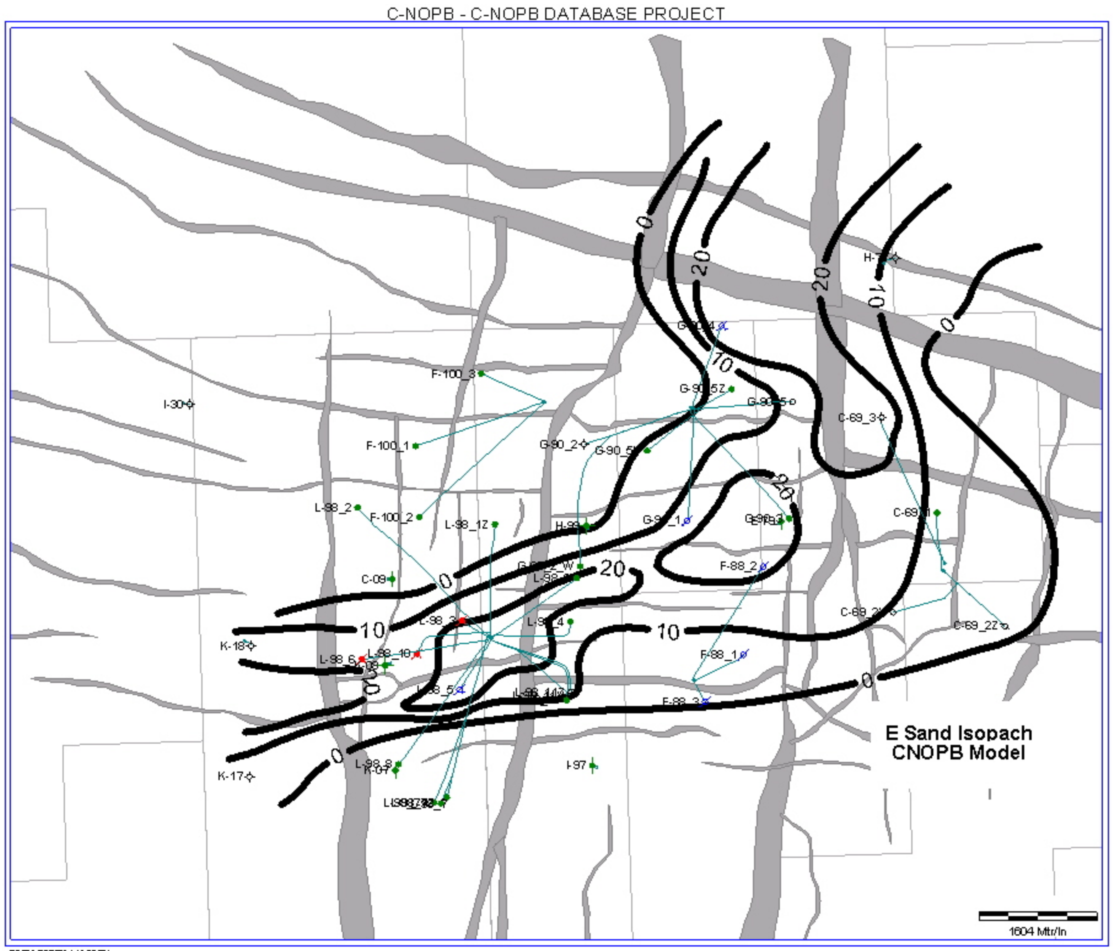
Proponent's UC2A sand Isochore



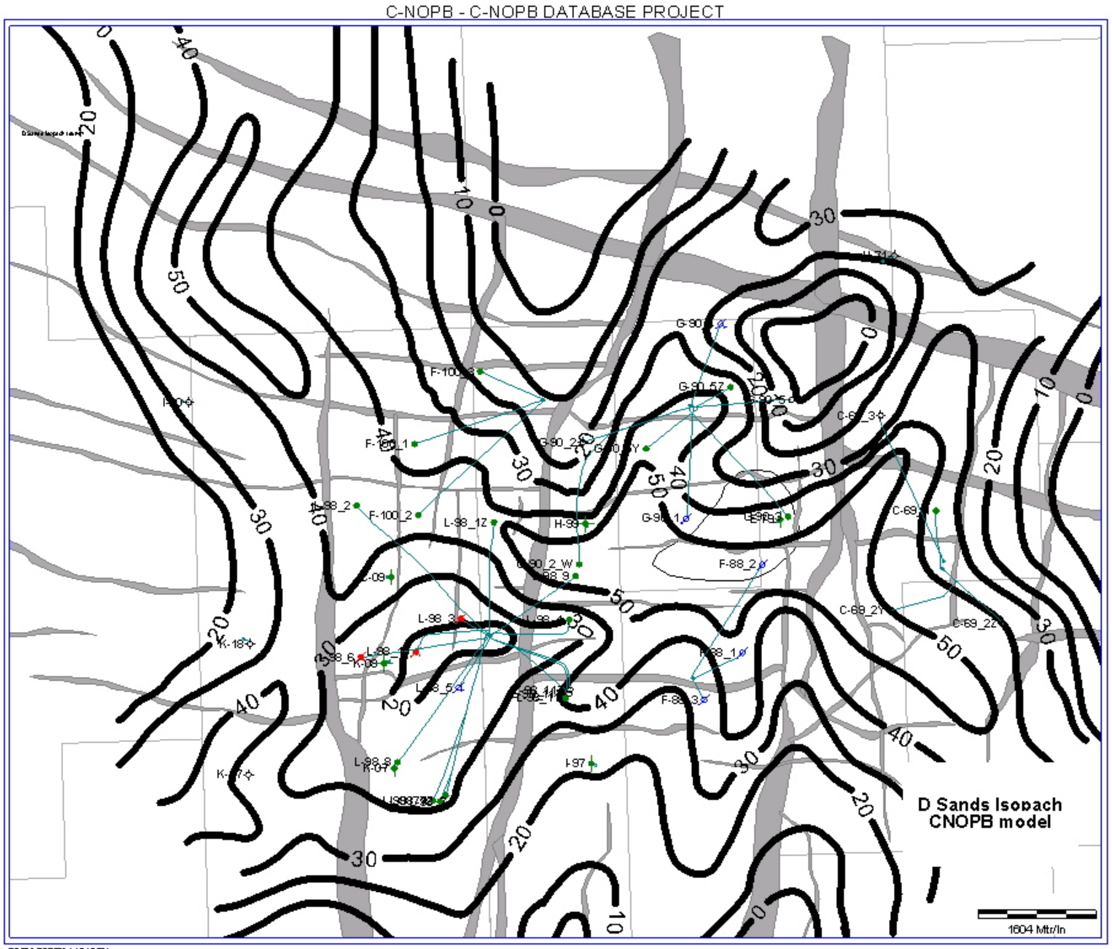
Proponent's LC2A sand Isochore

Appendix B

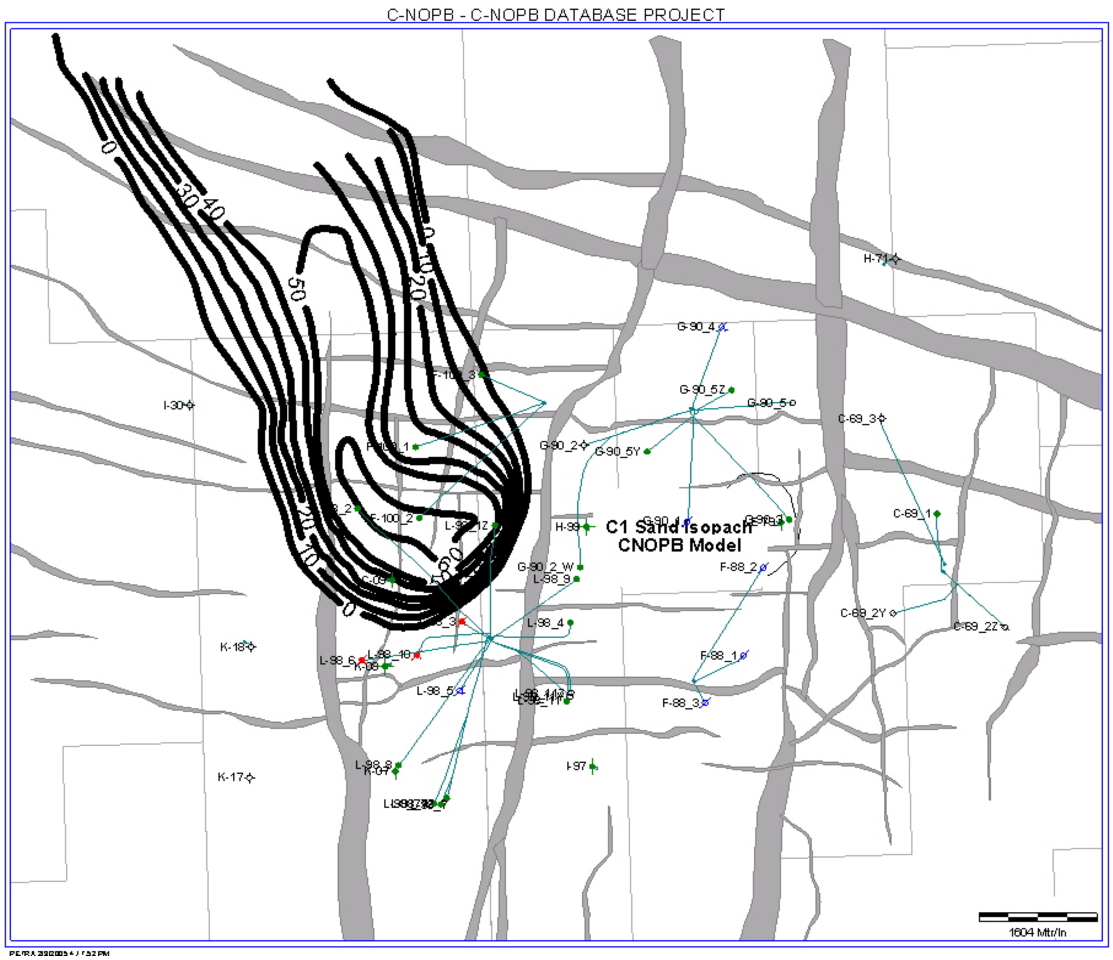
C-NLOPB's Isopachs



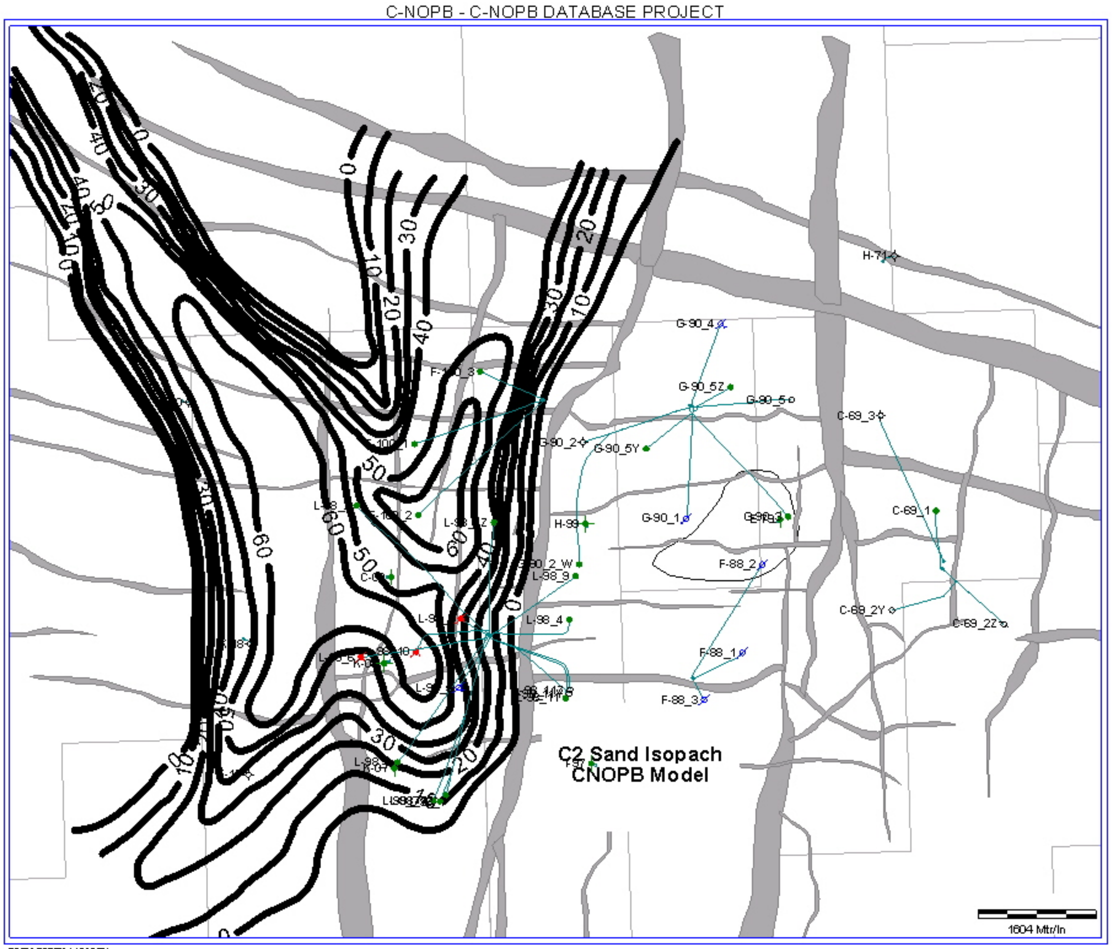
C-NLOPB's E Sand Isopach



C-NLOPB's D Sand Isopach



C-NLOPB's C1 Sand Isopach



C-NLOPB's C2 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

Appendix D

Glossary

Appendix 4
Glossary

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

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
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
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