DECISION 2002.01

RESPECTING

THE AMENDMENT
TO THE
TERRA NOVA DEVELOPMENT PLAN

OCTOBER 2002

Disponible en francais

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1. Summary

On January 12, 2000, Petro-Canada (Proponent) on behalf of the Terra Nova owners submitted an application under Section 34 of the Newfoundland Offshore Area Petroleum Production and Conservation Regulations to amend the approved production rate for the Terra Nova field to increase the annual oil production rate from 16 000 m^3/d (100,600 b/d) to 23 850 m^3/d (150,000 b/d).

The effects of these proposals would be to increase the authorized maximum annual production from about 5.8 million cubic metres (36.7 million barrels) to 8.7 million cubic metres (54.8 million barrels). The Canada-Newfoundland Offshore Petroleum Board (the Board) deemed the Proponent's request to be an application to amend the Terra Nova Development Plan previously approved by the Board. The Board's approval of such an amendment is a Fundamental Decision pursuant to the *Accord Acts* and, therefore, requires the approval of the Federal Minister of Natural Resources Canada and the Provincial Minister of Mines and Energy.

In support of its application, the Proponent submitted the document ***TN-PE-RD15-400-010, Terra Nova Development Application to Increase Field's Average Peak Oil Production Rate***. According to the Proponent, results of the studies conducted with production rates of 16 000 m^3/d (100,600 b/d), 23 850 m^3/d (150,000 b/d) and 31 800 m^3/d (200,000 b/d) indicate there is no effect or difference on recoverable reserves. Also, the Proponent notes that the system capacity is nominally 23 850 m^3/d (150,000 b/d) of oil.

The Board considered the January 12, 2000 application (Submission 1) and advised the Proponent that before the Board was prepared to make a decision on the production rate increase, additional information was required including among other items at least six months of production data to be included in the simulation update.

On August 6, 2002, the Proponent submitted the updated reservoir simulation studies in support of their rate increase application and also applied to increase the annual oil production rate for the Terra Nova field from the current 16 000 m^3/d (100,600 b/d) to 31 800 m^3/d (200,000 b/d) (Submission 2). In support of this request, the Proponent submitted the document ***Application to Increase the Annual Average Oil Production Rate for the Terra Nova Field***. On September 13, 2002, the Proponent submitted the document ***Supplemental Information to Application to Increase the Annual Average Oil Production Rate for the Terra Nova Field*** which contained further information requested by the Board.

For the purpose of this Decision Report, the Board has considered the information included in the January 12, 2000 application (Submission 1) and the information included in the August 6 and September 13, 2002 submissions (Submission 2) to constitute "the Application" under consideration.

In July 2002, the Proponent conducted a capacity test, which demonstrated that the production capacity of the oil and gas processing facilities is in excess of 23 800 m^3/d

(150,000 b/d). Based on this information, the Board's Chief Safety Officer approved an increase in the maximum safety related capacity to 23 800 m^3/d (150,000 b/d) subject to concurrence of the certifying authority, which has since been received. Further testing beyond 23 800 m^3/d (150,000 b/d) is planned by the Proponent to determine the facilities' processing capacity and to identify opportunities to increase the production capacity of the facilities.

The Board has reviewed the Application to determine whether the proposed production rate increase would affect the environmental impact predictions made in the Terra Nova Environmental Impact Statement, or any of the conditions established by the Board in Decision 97.02. Because the Application involves only a change to the annual oil production rate approved in Decision 97.02, and does not involve any major modification to the facilities themselves, the Board has determined that it does not affect the approved Terra Nova Benefits Plan nor raise any new environmental issues. Therefore, the Board has concluded that neither revision of the environmental impact assessment for the project, nor further public review is required.

Based on its assessment of the information presented, the Board concurs with the Proponent that oil recovery from the Terra Nova field is not adversely affected by an annual oil production rate up to 31 800 m^3/d (200,000 b/d). Field depletion simulation has also demonstrated minimal affect on life of field from the annual production rate increase requested.

The Board has therefore approved the following:

Terra Nova Development Plan Amendment
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The Board approves the Proponent's Application to increase the annual oil production rate up to 31 800 m^3/d (200,000 b/d) subject to the conditions 2002.01.01, 2002.01.02 and 2002.01.03 set out below and the conditions contained in its Decision Report 97.02. The outstanding conditions are summarized in Appendix 3.

Under this approval, the maximum allowable annual oil production for the calendar year 2002 will be determined using the following daily average oil rates:

a) 16 000 m^3/d (100,600 b/d) from January 1, 2002 to the day immediately preceding the day upon which the Board's approval for an increase to the annual oil production rate becomes effective pursuant to Section 32 of the Acts; and,

b) the annual oil production rate of 23 800 m^3/d (150,000 b/d) from the date of the Board's approval for an increase to that rate becomes effective pursuant to Section 32 of the Acts.

For each calendar year thereafter, the maximum annual oil production rate shall be 23 800 m^3/d (150,000 b/d) or such other rate as shall have been approved by the Board considering appropriate regulatory, administrative and technical criteria. The Board may increase the annual oil production rate up to a maximum of 31 800 m^3/d (200,000 b/d).

Condition 2002.01.01
It is a condition of the Board's approval that:

> Prior to producing oil at a rate above 19 900 m^3/d (125,000 b/d) on a monthly basis, the Proponent must satisfy the Board's Chief Conservation Officer of the following:
> a) Stable operation of the gas injection system, and
> b) That the metering and flow calculations and allocation system are functioning properly and providing reasonable accuracy for reservoir management and fiscal purposes.

Condition 2002.01.02
It is a condition of the Board's approval that:

> 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.

Condition 2002.01.03
It is a condition of the Board's approval that:

> 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.

2. The Present Application

2. 1 Background

In the Terra Nova Development Plan submitted in 1996, the Terra Nova owners presented an oil production forecast with a peak production rate of 16 000 m^3/d (100,600 b/d). The production forecast was based on the proposed production facility design capacity of 19 900 m^3/d (125,000 b/d).

On January 12, 2000, Petro-Canada (Proponent) on behalf of the Terra Nova Owners submitted an application under Section 34 of the Newfoundland Offshore Area Petroleum Production and Conservation Regulations to amend the approved production rate for the Terra Nova Field to allow an annual oil production rate up to 23 850 m^3/d (150,000 b/d) (Submission 1). In support of its application, the Proponent submitted the document ***TN-PE-RD15-400-010, Terra Nova Development Application to Increase Field's Average Peak Oil Production Rate***. According to the Proponent, results of the studies conducted with production rates of 16 000 m^3/d (100,600 b/d), 23 850 m^3/d (150,000 b/d) and 31800 m^3/d (200,000 b/d) indicate there is no effect or difference on recoverable reserves. Also, the Proponent notes that the system capacity is nominally 23 850 m^3/d (150,000 b/d) of oil.

Production rates are covered in the Newfoundland Offshore Area Petroleum Production and Conservation Regulations Part V Section 34. More specifically this section states that:

> ***An operator shall produce petroleum from a pool or field in accordance with good production practices to achieve maximum recovery of petroleum from the pool or field and at the applicable rate specified in the approved development plan for that pool or field.***

The applicable rate in the approved Terra Nova Development Plan is the rate provided in the production forecast. This rate is based on the approved depletion scheme for a pool or field. The proposed rate increase has been deemed an amendment to Part 1 of the Terra Nova Development Plan. As the production rate constitutes an amendment to Part 1 of the plan, it is a fundamental decision and will require the approval of the appropriate Federal and Provincial Ministers.

The Board has reviewed the application to determine whether the proposed production rate increase would affect the environmental impact predictions made in the Terra Nova Environmental Impact Statement, or any of the conditions established by the Board in Decision 97.02. Because the application involves only a change to the average daily oil production rate approved in Decision 97.02, and does not involve any major modification to the facilities themselves, the Board has determined that it does not affect the approved Terra Nova Benefits Plan nor raise any new environmental issues. Therefore, the Board has concluded that neither revision of the environmental impact assessment for the project, nor further public review is required.

The Board reviewed the information submitted in support of the application, met with the Proponent's representatives to discuss the information, obtained a copy of the reservoir simulation files and ran the reservoir simulation, and reviewed the results using its reservoir simulation software. The Board concurred with the Proponent that the geological interpretation and simulation studies presented, support the view that oil recovery from the Terra Nova reservoir is not adversely affected by peak oil production rates up to 31 900 m^3/d (200,000 b/d). However, prior to permitting production at the proposed rate, the Board required the following:

- The reservoir simulation study conducted to assess rate sensitivity be updated to include production data and new geological data and the results submitted to the Chief Conservation Officer. It was recommended that at least six months of production data should be included in the simulation update.

- Demonstration of stable operation of the oil and gas processing and injection systems.

- Testing of the processing facilities, in accordance with a program approved by the Board's Chief Safety Officer and Chief Conservation Officer, to establish the capacity of the facilities.

- The Chief Conservation Officer be satisfied that the metering and flow calculation and allocation system is functioning properly and providing reasonable accuracy for reservoir management and fiscal purposes.

- The Chief Safety Officer is satisfied that safety issues are adequately addressed.

On August 6, 2002, the Proponent submitted the updated reservoir simulation studies in support of their rate increase application and also applied to increase the annual average oil production rate for the Terra Nova field from the current 16 000 m^3/d (100,600 b/d) to 31 800 m^3/d (200,000 b/d) (Submission 2).

For the purpose of this Decision Report, the Board has considered the information included in the January 12, 2000 application (Submission 1) and the information included in the August 6 and September 13, 2002 submissions (Submission 2) to constitute "the Application" under consideration.

The following section of the report presents an overview of the Proponent's reservoir simulation study provided August 6, 2002 in support of its application to increase the annual oil production rate for the Terra Nova field and the Board's review of the study and response to the rate increase application. The reader is referred to Appendix 1 for an overview of the Proponent's initial production rate increase request, submitted January 12, 2000 and the Board's review of, and response to, this request.

2. 2 Proponent's August 2002 Application

On August 6, 2002 the Proponent submitted the document "***Application to increase the Annual Average Oil Production Rate for the Terra Nova Field***" and applied to increase the annual average oil rate for the Terra Nova field from 15 900 m^3/d (100,600 b/d) to 31 800 m^3/d (200,000 b/d). The document provided the results of an updated reservoir simulation study in compliance with the Board's response to their original application. The simulation study included the following sensitivities:

1. Field peak oil rates from 16 000 m^3/d (100,000 b/d) to 39 750 m^3/d (250,000 b/d) using a black oil model.
2. Well peak oil rates from 3000 m^3/day to 7000 m^3/day using a black oil model.
3. Well peak oil rates from 3000 m^3/day to 7000 m^3/day using a black oil model and modified permeability profiles to reflect worse case recovery scenarios.
4. Well peak oil rates from 3000 m^3/day to 7000 m^3/day using a compositional simulation model at reservoir pressures above the predicted minimum miscibility pressure.

On September 13, 2002, the Proponent submitted the document "***Supplemental Information to Application to increase the Annual Average Oil Production Rate for the Terra Nova Field***" which contained further information requested by the Board. According to the Proponent, all cases demonstrated that recovery is not sensitive to peak rates. The Proponent noted that although the model will change as wells are drilled and new information is obtained, the model still accurately assesses the relative effect of peak oil rates on ultimate recovery. The Proponent stated that approval of this application would not compromise the gas conservation strategy or ultimate recovery. This part of the report presents an overview of the Proponent's reservoir simulation study and the Board's review of the study and response to the rate increase.

2.2.1 Geological Model

The Proponent used information from twenty-eight wells (Appendix 2) which penetrated the Jeanne d'Arc sands in the Terra Nova field area to construct a geological model for the field. All wells up to L-98 5 have been incorporated in the model. While the results of the L-98 7Z well were not incorporated in the model, according to the Proponent, logs acquired from the well indicate that the well should not materially change the model in this area. The geological model interpretation is Alternative 2 presented in the Commercial Discovery Declaration Application for the Terra Nova Development submitted to the Board in June 1998. This model is based on an alluvial/fluvial to marginal marine deposition within a compound incised valley and is comprised of 5 major and 2 minor oil bearing sands. The Proponent's Jeanne d'Arc stratigraphy for this depositional system is provided in Figure 2.1

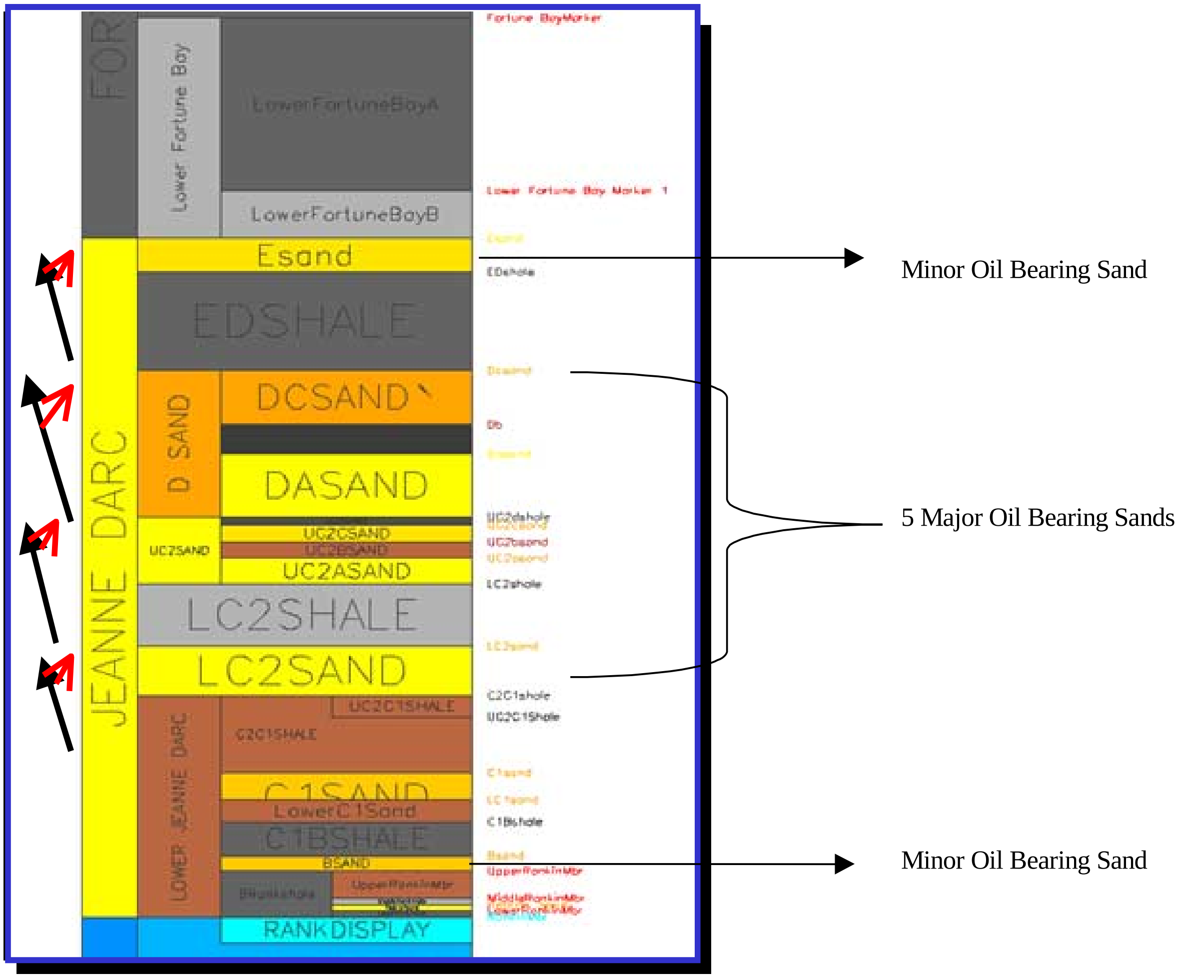


Figure 2.1: Petro-Canada Jeanne d' Arc Stratigraphy

Source: After Petro-Canada 2002

The Proponent generated a structure map on the seismically and geologically defined UC2d flooding surface. Isopach maps were created for each of the sand and shale units. For the sand units the following maps were prepared and provided:

- Net-to-gross based on a shale volume cutoff of 40% and a porosity cutoff of 8%
- Net porous sand
- Porosity
- Permeability.

2.2.2 Production History and Reservoir Simulation Model

A review of the history acquired from the field to date from the L-98 1Z, L-98 2, L-98 4, G-90 2W and G-90 3 production wells, F-88 1 and G-90 1 water injection wells and L-98

3 gas injection well was presented (Figure 2.2). Production was initiated on January 20, 2002, while water and gas injection was initiated on February 24 and May 15, 2002 respectively. According to the Proponent, in the Graben, production showed good communication between L-98 1Z and L-98 3 wells and there is also communication between these wells and L-98 2 and L-98 5 wells across seismically-defined faults. The Proponent notes, however, that this communication is somewhat baffled. In the East Flank the Proponent notes that early production data showed good communication between wells within fault blocks and across seismically defined faults.

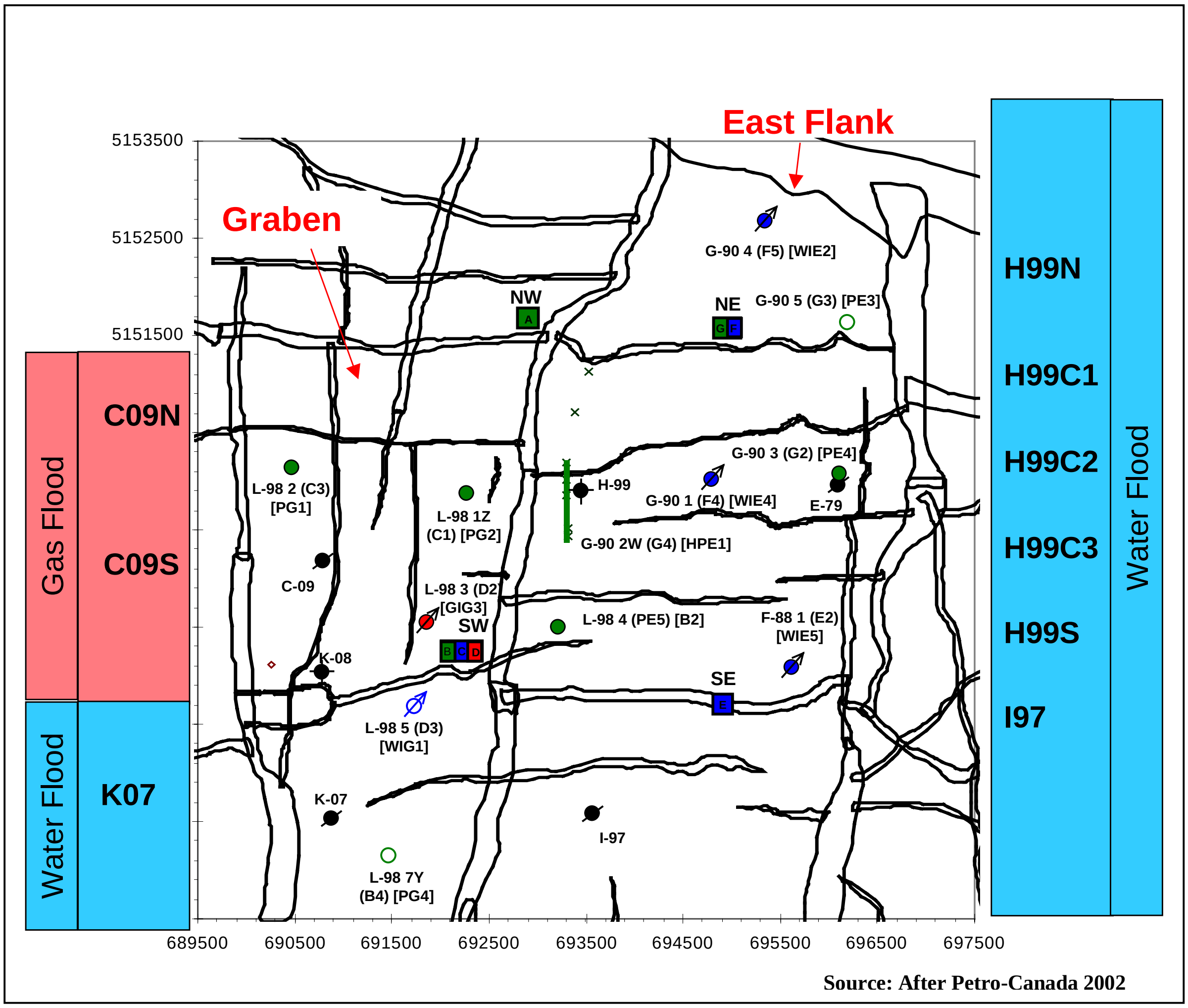


Figure 2.2: Terra Nova Drilled Well Locations and Fault Block Designations

The Proponent created a reservoir simulation model for the Field consisting of 130 by 104 areal grids and 41 layers for a total of 554,320 grid cells. The porosity, net-to-gross and permeability maps generated for each sand were used to populate the grid. Water saturation was assigned to each grid on the basis of capillary pressure data. According to the Proponent the equation of state model for Terra Nova was based on fluid samples acquired from the development wells. Three fluid regions, Graben/Graben North, East Flank and Far East, were identified by the Proponent and pressure volume and temperature (PVT) properties were developed for the fluids in each of the regions. Different fluid properties were developed for the time prior to and following gas injection due to the difference in process conditions. A summary of the PVT properties is shown in Table 2.1. The Proponent also investigated the minimum miscibility pressure and predicted this pressure to be 311 Bara based on the current gas injection stream.

Table 2.1
Terra Nova General PVT Properties (with and without Gas Compression)

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	1.424	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	657.96
Oil Gradient	bar/m	0.06981	0.07031	0.065
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

General Terra Nova PVT Properties (Non-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	309.81
Tres	C	96	90	93.7
Bo @ Pres	rm3/Sm3	1.429	1.422	1.567
Bo @ Pb	rm3/Sm3	1.468	1.456	1.531
Bg @ Pres	rm3/Sm3	0.00368	0.00378	0.00335
Bg @ Pb	rm3/Sm3	0.00505	0.00508	0.00404
Bw @ Pres	rm3/Sm3	1.032	1.029	1.030
Rs	Sm3/Sm3	149.84	144.14	194.53
deno @ Pres	kg/m3	711.89	716.97	657.96
Oil Gradient	bar/m	0.06981	0.07031	0.065
deno @ Pb	kg/m3	692.97	700.26	659.39
deno @ ST	kg/m3	857.80	863.31	844.82
API		33.46	32.40	35.99
deng @ Pb	kg/m3	181.39	176.48	234.38
deng @ ST	kg/m3	1.0706	1.0903	0.9910
gas gravity		0.875	0.891	0.810
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	0.5080
uo @ Pb	cp	0.4627	0.5346	0.4142
ug @ Pres	cp	0.0255	0.0235	0.0410
ug @ Pb	cp	0.0229	0.0216	0.0348
uw @ Pres	cp	0.364	0.379	0.367

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

Source: After Petro-Canada 2002

The oil-water and gas-oil relative permeability used by the Proponent in the model remained unchanged from that used for the Reservoir Basis for Terra Nova Development provided to the Board in March 1998. These data are shown in Figure 2. A water-oil contact of 3580 metres subsea was used for the Graben. For the East Flank, the Proponent notes two oil-water contacts are inferred. The H99N and H99C1 fault blocks are assumed to have an oil-water contact of 3381 metres subsea based on capillary modeling; all other fault blocks in the East Flank have an inferred contact of 3351 metres subsea. The Proponent noted no oil-water contact has been encountered in the Far East.

The following production constraints were used in the model:

Total Liquid Production Rate	45 300 m^3/d
Gas Production Capacity	8.5 $10^6 m^3/d$
Gas Injection Capacity	7.32 $10^6 m^3/d$
Well Maximum Liquid Rate	7 000 m^3/d
Water Injection Well Maximum Rate	17 000 m^3/d
Gas Injection Well Maximum Rate	4.0 $10^6 m^3/d$

According to the Proponent the water injection fault blocks were simulated with a voidage replacement of 1.0 when the optimum reservoir pressure above bubble point was achieved.

2.2.3 Production History Match

The Proponent conducted a history match of the first six months of production data to calibrate the model and presented the results of the match. During the history match, the reservoir simulation model is run with the oil production and gas and water injection rates for each well set as recorded in the field. Parameters such as pressure and water and gas production are predicted and compared with the actual recorded data. Parameters in the reservoir simulation model are adjusted to achieve a reasonable match prior to making prediction beyond the history match period. According to the Proponent, history matching indicates that the key variables for the Graben are communication areally across seismically defined faults and communication vertically between sands. For the East Flank, the key variables for history matching are communication areally across seismically defined faults, communication vertically between sands and connected pore volume. The Proponent notes that a good history match was achieved for the Graben wells and an acceptable match was achieved for the East Flank wells. However, it was noted that further work is needed with respect to matching the L-98 4 and G-90 2W wells. Also, the Proponent noted that a history match of the wireline pressure data from the G-90 4 and G-90 5 wells was not included in the model at this time. These wells showed depletion, relative to East Flank virgin pressure gradients, of about 80 and 1000 kPa, respectively. The minor depletion in G-90 4 can be accommodated without modification to the pore volume, while a reduction to the pore volume would be required to match the 1000 kPa pressure reduction at G-90 5. The Proponent attempted no reduction in pore volume since the pressure match in G-90 1, G-90 2W and G-90 3 wells would not be affected by the changes, and a better definition of the stratigraphy based on further drilling in the area will allow for a more robust history match. A comparison of the Proponent's base geological model and reservoir simulation model oil in place for the Graben and East Flank is shown in Table 2.2.

Table 2.2
Graben and East Flank Stock Tank Oil Originally in Place Comparison

Graben Model STOOIP Comparison (3580 m ss OWC) ($MMsm^3$)		
Fault Block	2002b Base Geological Model	2002b History Match
K07	16.594	16.594
C09SW	15.096	15.096
C09SC	15.722	15.722
C09SE	13.439	13.439
C09N	25.871	25.871
N. Graben	13.626	13.626
Total	100.348	100.348

East Flank Model STOOIP Comparison (3351/81 m ss OWC) ($MMsm^3$)		
Fault Block	2002b Base Geological Model	2002b History Match
H99N	6.300	6.300
H99C1	8.127	8.127
H99C2	20.503	19.567
H99C3	20.699	14.502
H99S	6.302	6.302
I97	2.399	2.399
Attic	7.446	7.446
Total	71.776	64.643

2.2.4 Base Case Depletion Plan

The base case depletion plan is as previously submitted, which provides for the East Flank and the Graben K07 fault block being developed under waterflood, and the Graben C09 blocks being developed with up-dip gas injection. Water injection may also be used to supplement the gas injection if there is insufficient gas. The Proponent noted with this application that the North Graben and Far East are being included in the depletion plan. Both of these areas are proposed to be developed under waterflood. The Proponent notes that further drilling is required to confirm the development potential of the Far East.

The Proponent summarized the main operating strategy to be used as follows:

1) Maintain miscible conditions in the gasflood. The reservoir pressure will be at or above the minimum miscibility pressure in each fault block at first initiation of gas injection into that block. Also, the gas balance over the short and long-term will be maintained in the C-09 block.
2) Maintain reasonable waterflood pressures at a level above the bubble point.
3) Continue with a balanced well schedule. Waterflood and gasflood priorities will be balanced; development and delineation will be balanced; short-term and long-term production will be balanced; and, slot utilization will be efficient.
4) Initiate gas-lift when required to optimize production and/or allow better reservoir management.

The base case for the Graben (including the North Graben) and the East Flank has 25 wells, comprised of 14 producers and 11 injectors. The Proponent notes that three additional sidetracks are needed to recover the reserves and that the producing wells are primarily deviated. The proposed well locations are provided in Figure 2.3. The peak oil rate for the base case is equivalent to the approved annual production rate of 16 000 m^3/d. The Proponent presented the simulation production forecast (Figure 2.4) and noted that the profile does not include an economic cutoff. According to the Proponent, total economic reserves remain at 58.8 10^6 m^3 (370 million barrels).

The full field base case assumes development of the Far East with 8 wells, 4 producers and 4 water injectors. The Proponent notes only one well has been drilled into the Far East to date and a second well is planned for the third quarter 2002; also, that the well schedule includes a ninth Far East well to delineate the northern area of the Far East, and that one of the nine wells will find no reservoir. The preliminary well location and simulation production forecast presented by the Proponent are provided in Figures 2.5 and 2.6, respectively. The Proponent noted that the production profile does not include an economic cutoff.

According to the Proponent, the original oil-in-place for the Far East base case simulation is 45.72 $10^6 m^3$ and the economic reserves for this area is estimated to be 15.9 $10^6 m^3$ (100 million barrels).

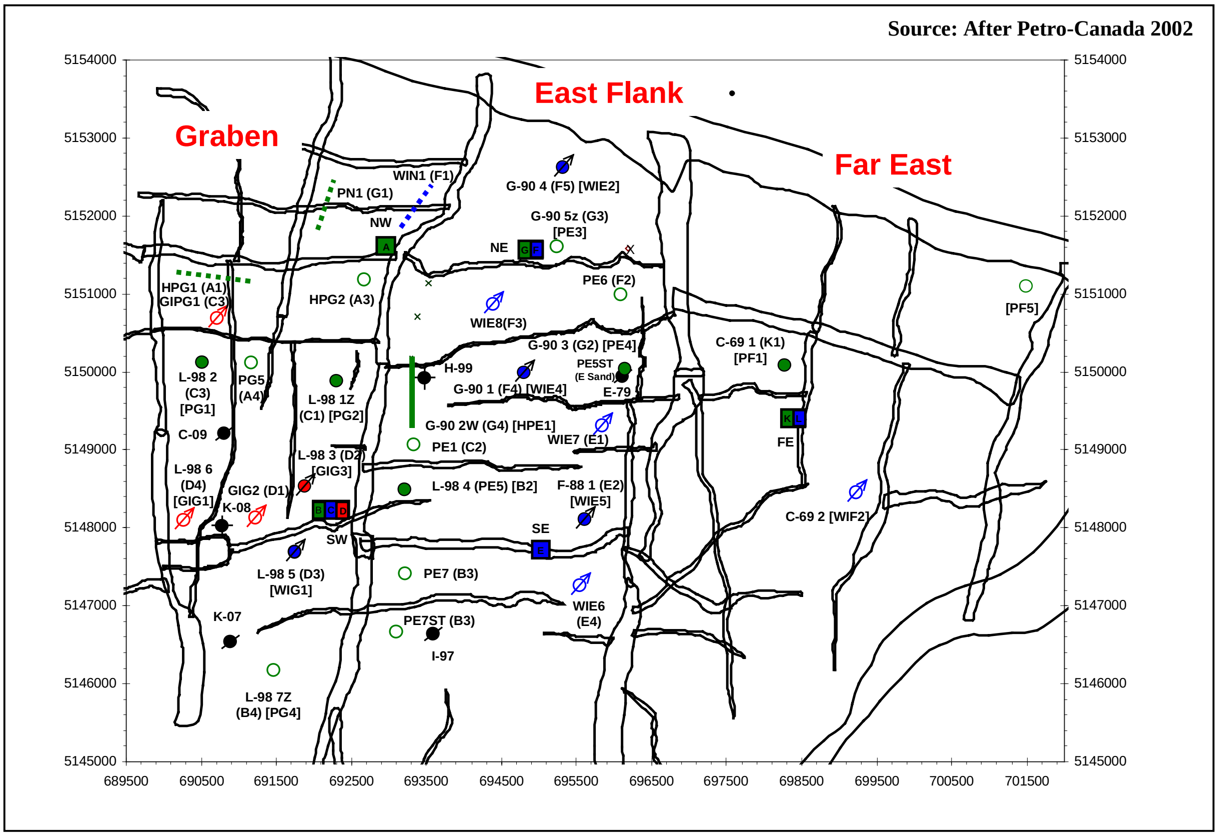


Figure 2.3: Full Field Development Plan – Graben and East Flank

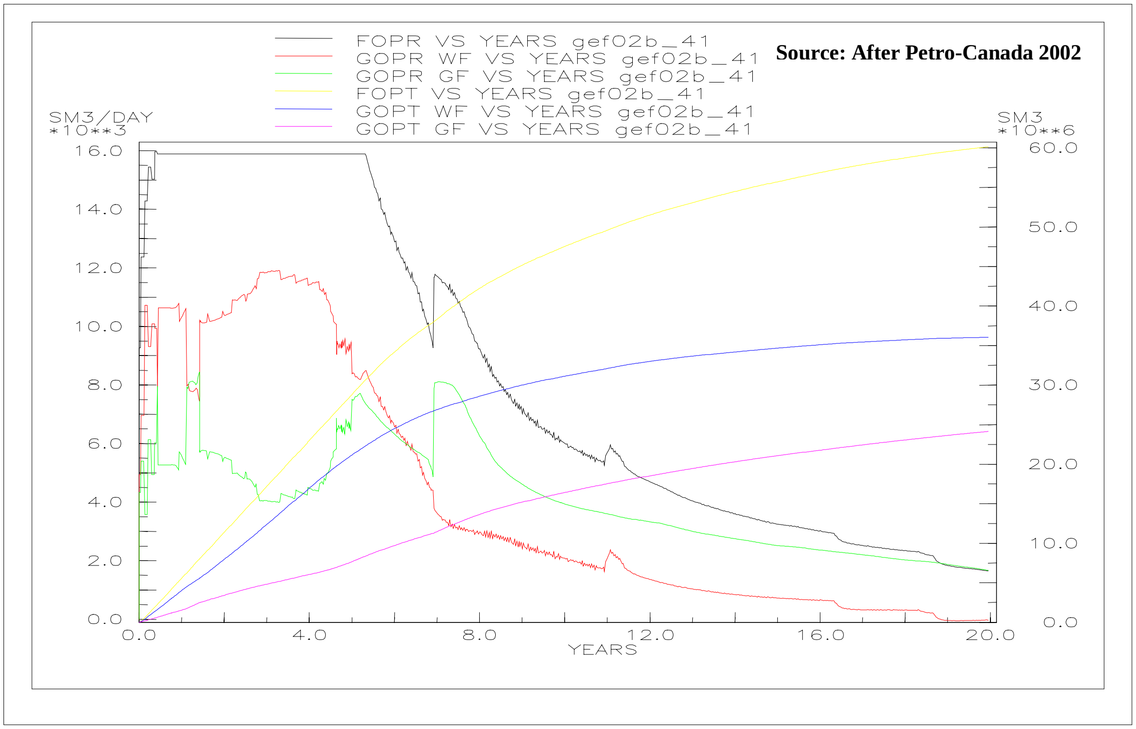


Figure 2.4: Graben/East Flank Base Case Oil Production Profile

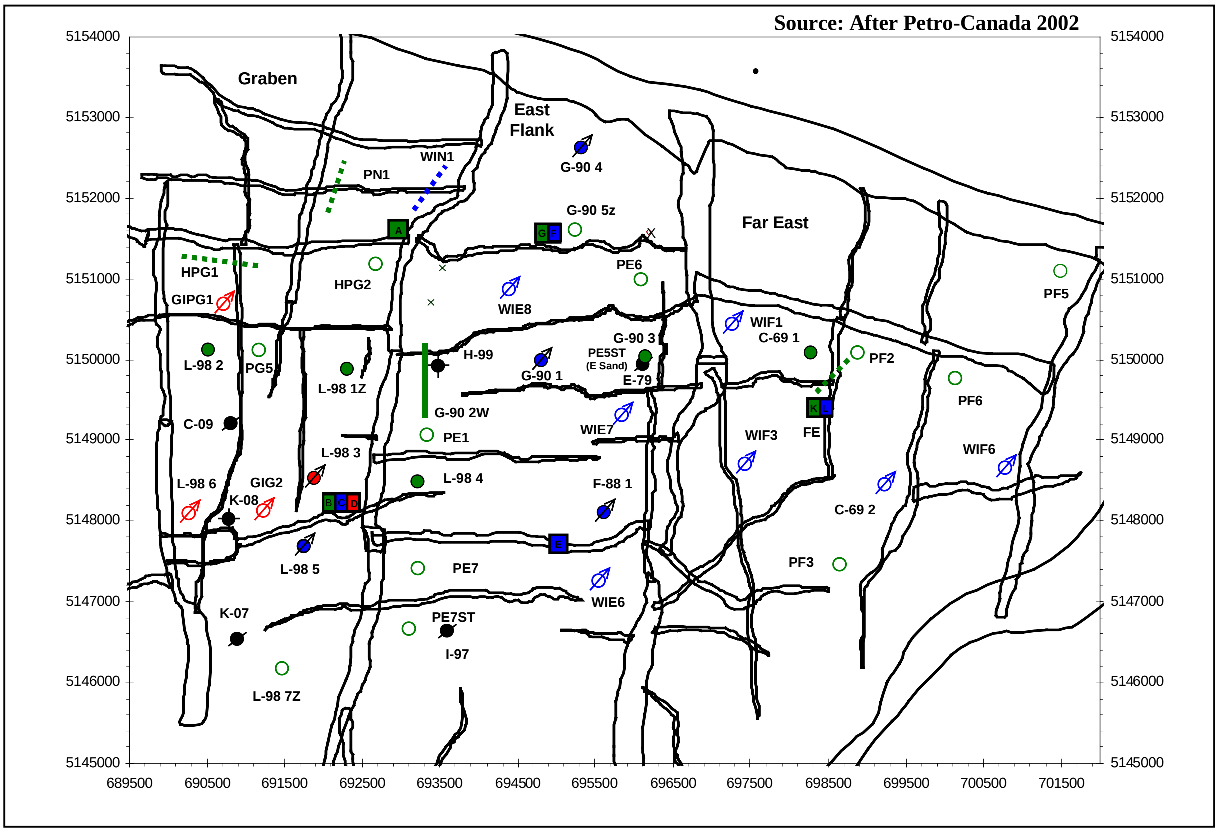


Figure 2.5: Full Field Development Plan including Far East

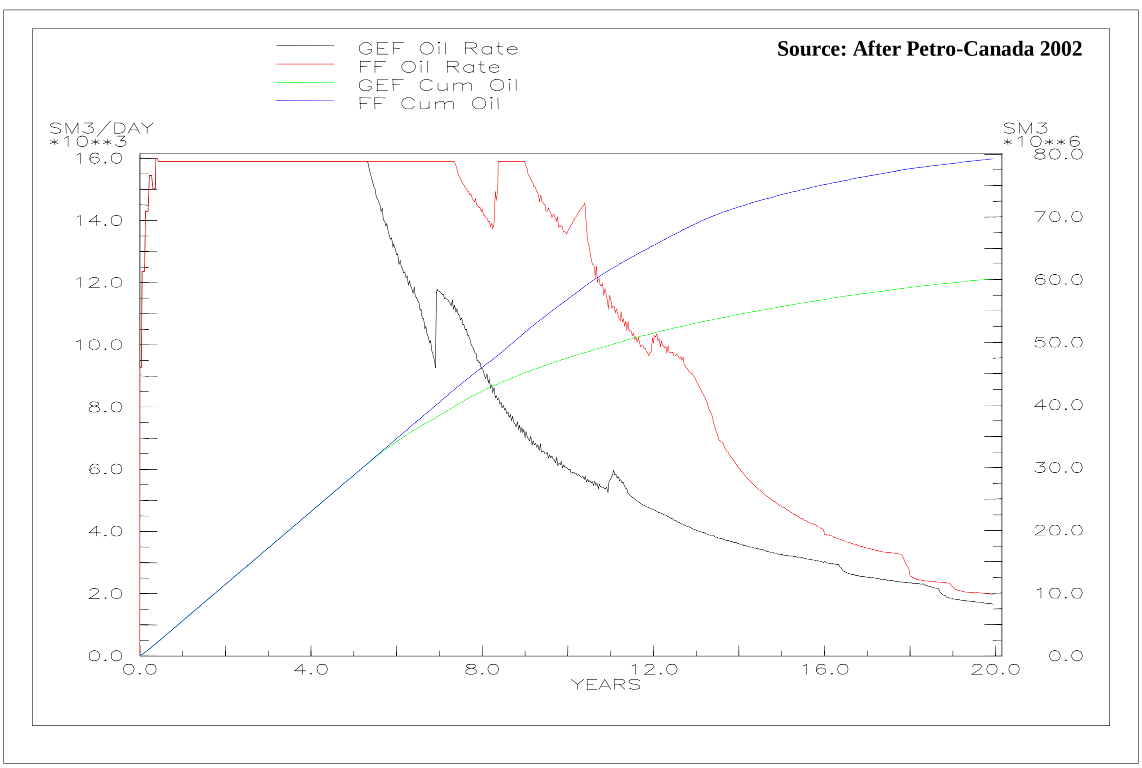


Figure 2.6: Full Field Base Case Oil Production Profiles for Graben/East Flank and Graben/East Flank/Far East

The Proponent noted that the current model will be updated as new information is acquired from drilling and production activities, and will use the following information to assess production trends:

1) Well production and injection data including GOR and watercut
2) High density bottom-hole pressure data from production wells
3) RCI pressure data
4) Fluid analysis data
5) PLT data

2.2.5 Production Rate Sensitivity Study

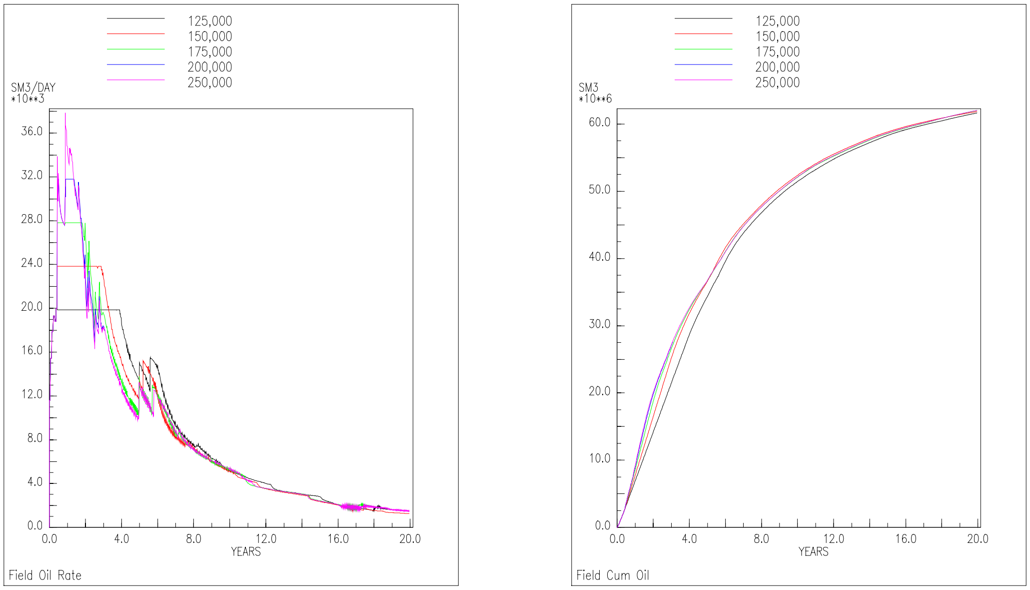
To assess the effect of peak field oil rate on ultimate recovery, the reservoir simulation models for the Graben and East Flank and the Graben, East Flank and Far East were run at the following peak oil rates:

1) 19875 m^3/day (125,000 b/d)
2) 23850 m^3/day (150,000 b/d)
3) 27820 m^3/day (175,000 b/d)
4) 31800 m^3/day (200,000 b/d)
5) 39750 m^3/day (250,000 b/d).

According to the Proponent, all other constraints were unchanged for the base case models. Both models predicted practically identical recoveries. The Proponent also provided a detailed listing of the production and injection profiles for each well, and the recovery efficiency for each of the reservoir sandstone units. A summary of the oil recovery and recovery efficiency for the Graben, East Flank and Far East model presented by the Proponent is shown in Table 2.3. The Production profiles for the Graben/East Flank and the Graben/East Flank/Far East models are shown in Figures 2.7 and 2.8, respectively. According to the Proponent, these plots indicate that oil recovery is not sensitive to the peak production rate.

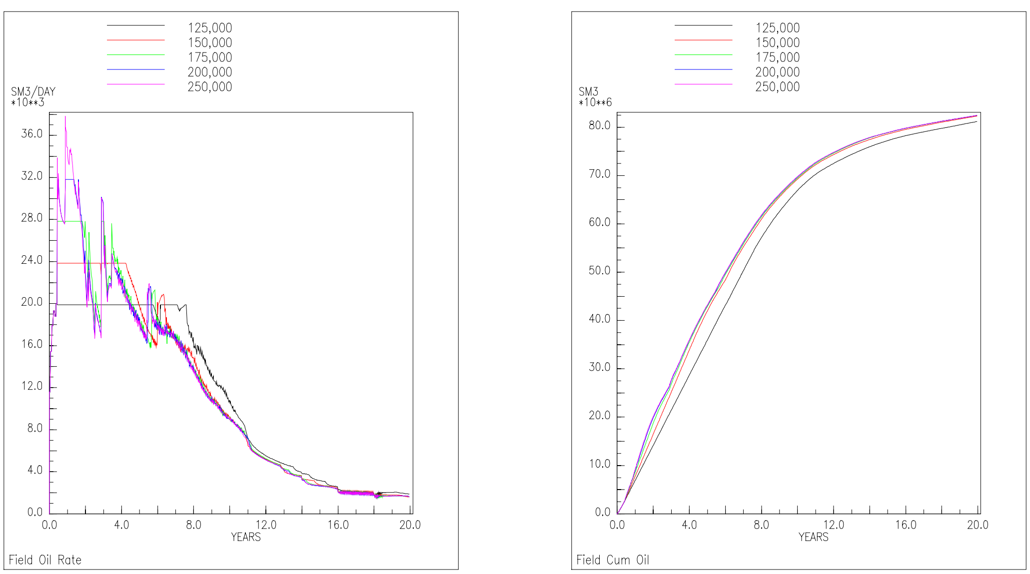
Table 2.3
Impact of Peak Oil Rate on Full Field Model Recovery by Mechanism
(Source: After Petro-Canada 2002)

Peak Rate (m^3/day)	Cumulative Totals					
	Graben/East Flank Waterflood Oil ($10^6 m^3$)	Graben/East Flank Waterflood Recovery Factor (%)	Far East Waterflood Oil ($10^6 m^3$)	Far East Waterflood Recovery Factor (%)	Gasflood Oil ($10^6 m^3$)	Gasflood Recovery Factor (%)
15900	36.36	38.33	20.68	40.53	23.94	34.14
19875	35.92	37.87	20.33	39.84	24.92	35.53
23850	36.10	38.06	20.32	39.82	25.87	36.89
27820	36.45	38.43	20.31	39.80	25.69	36.63
31800	36.38	38.35	20.33	39.84	25.73	36.69
39750	36.44	38.41	20.29	39.76	25.72	36.67



Source: After Petro-Canada 2002

Figure 2.7: Graben/East Flank Peak Rate Sensitivity Oil Production Profiles



Source: After Petro-Canada 2002

Figure 2.8: Graben/East Flank/Far East Peak Rate Sensitivity Oil Production Profiles

2.2.6 Well Rates, Permeability Profile and Miscibility Sensitivity Studies

The Proponent also investigated the impact on oil recovery of producing each of the Graben and East Flank producers at peak production rates of 3000, 5000 and 7000 m^3/d. All well sensitivities were run to a gas-oil-ratio cutoff of 3000 m^3 /m^3, or a watercut cutoff of 95%. The Proponent also presented the results of additional sensitivities assuming a coarsening-upward permeability profile for the gasflood, and a coarsening-downward permeability profile for the water flood. According to the Proponent, these simulation runs showed that oil recovery is not sensitive to peak well rates.

A compositional reservoir model was constructed by the Proponent to assess the impact of short-term reservoir pressure drops on oil recovery. The Proponent notes that this model indicates that the gas flood recovery was relatively insensitive over the pressure range 290 – 350 bar, Figure 2.9. Also, pressure fluctuation does not adversely impact the compositional process or recovery. Fine and coarse scale compositional models were tested to determine the impact of production rate to the miscible process. The results of these studies are summarized in Table 2.4. The Proponent states these runs demonstrate no rate sensitivities.

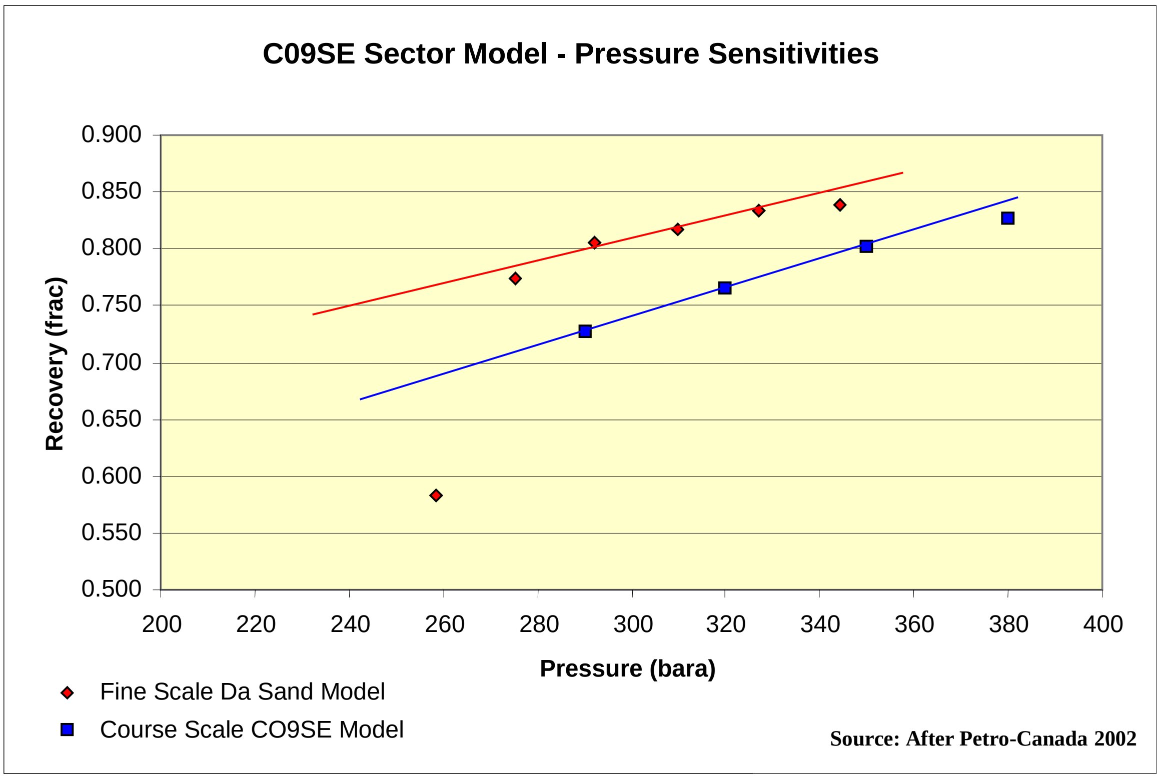


Figure 2.9: Impact of Reservoir Pressure on Compositional Simulation Oil Recovery Factor

Table 2.4
Compositional Simulation Rate Sensitivity Results (Source: After Petro-Canada 2002)

Grid Type	Peak Rate (m^3/day)	Sands Present	Pressure (bara)	STOOIP (10^6 m^3)	Recovery (%)
Fine	950	1	340	0.846	83.8
Fine	300	1	340	0.846	84.5
Coarse	5000	Dc, UC2c	320	6.634	76.6
Coarse	3000	Dc, UC2c	320	6.634	76.6
Coarse	7000	Dc, UC2c	320	6.634	76.5

2.3 Board's Review

The Board reviewed the reservoir simulation report submitted in support of the application, acquired and reviewed the Proponent's reservoir simulation model, and conducted a review of reservoir, geological and production data acquired to date. Since the initial submission to the Board, the following events have occurred at the Terra Nova field:

- Ten wells have been drilled
- Oil has been confirmed in the Far East with the C-69 1 well
- Oil-water contacts have been established on the East Flank
- Oil production was initiated on January 20, 2002. In excess of 2.9 million cubic metres of oil has been produced from five wells in the Graben and East Flank area
- Water injection in the East Flank was initiated on February 24, 2002
- Gas injection in the Graben was initiated on May 15, 2002
- Facility capacity testing up to 23 835 m^3/d was conducted in July, 2002

These events provided a substantial quantity of new information to assess reservoir and facility performance and construct geological and reservoir simulation models. The Board acknowledges the Proponent has conducted a comprehensive assessment of this information in support of the rate increase request.

2.3.1 Geological Model Review

In its review of the Proponent's initial request to increase the annual oil production rate, the Board concurred with the Proponent that there are several possible geological models with varying sand and shale correlations that can reasonably be put forward. Also, the Board noted the presence of calcite cement and its potential impact on oil-in-place estimates and communication across faults. In the Board's view, having a reliable geological model to predict individual sand units and the extent of the calcite cemented zones, presents the greatest challenge. The Jeanne d'Arc sandstones have been encountered in all wells, but the sandstone units, as defined by the stratigraphy, have not always been as prognosed. Also, in the case of the G-90 2, G-90 4, G-90 5 and L- 98 7 wells and their side tracks, the sandstones were present but the net pay was significantly reduced by the presence of calcite cement. The Proponent continues to work on the geological model for the field. This is typical for any field. The geological model and calcite cementation will be resolved as additional data is acquired from drilling and production activities, but there will always be an element of uncertainty. The Board, however, believes that given the range of possible geological interpretations, the model used by the Proponent for the reservoir studies is reasonable.

The Board conducted an analysis of the open hole logs acquired from wells drilled in the Terra Nova field. This analysis is in good agreement with that presented by the Proponent. The Board also reviewed the wireline pressure data and open hole logs to assess the oil-water contacts. According to the Board's review, the oil-water contact of 3580 metres subsea for the Graben area used by the Proponent in its reservoir simulation study is slightly higher than the oil-water contact of 3563 metres subsea estimated by the Board for this area. However, given the uncertainties in the data, the Board believes the oil-water contact used by the Proponent is reasonable. Also, consistent with the Proponent's interpretation, this analysis indicates at least two oil-water contacts in the East Flank. According to the Board's analysis, an oil-water contact of 3351 metres subsea is inferred from the L-98 4 and F-88 1 pressure data. This concurs with the contact used by the Proponent for the East Flank fault blocks, except blocks H99N and H99C1. In fault block H99N, an oil-water contact has been inferred by the Board at 3342.5 metres subsea based on the wireline pressure data obtained from the G-90 4 well. However, from the Board's analysis of the open hole log data, water has been determined to exist at 3338.7 metres subsea, which is slightly shallower than indicated from the wireline pressure data, and significantly shallower than the oil-water contact of 3381 metres subsea used by the Proponent. In subsequent information provided by the Proponent, a sample taken from what is interpreted to be the water zone, recovered 20% water and 80% oil base mud filtrate which was cut with light hydrocarbons. The Proponent believes that this supports the presence of mobile oil. The Board believes that the results are not conclusive and further data is necessary to confirm the oil-water contact in this area. While the contact used by the Proponent will increase the oil in place, in the Board's view it will not significantly affect the results of the rate sensitivity studies.

2.3.2 Reservoir Simulation Model Review

The Board reviewed data and assumptions used to construct the reservoir simulation model and believe they are reasonable. However, the Board notes that data acquired from the G-90 4 well suggest that the oil encountered in the H99N fault block may be different from that acquired to date in the other East Flank fault blocks. However this is not expected to affect the results of the simulation study.

The Proponent conducted a comprehensive review of the production data and used this information to calibrate the reservoir simulation model. The Board believes that the Proponent achieved a good history match of the pressure data acquired from the wells drilled in the Graben to date, and concurs with the Proponent's view that the data supports both vertical communication between sands and across selected faults. Communication across the faults has been confirmed from the pressure data acquired to date. The Board notes that within the model controls, the Proponent had to use fairly high threshold shale thickness, 30 metres in fault block C09SE and 10 metres in other Graben fault blocks, which allowed communication to achieve the history match. The history match is not unique. There may be limited to no vertical communication between the D and C sands, and it would still be possible to achieve a reasonable match through flow across the faults. The Proponent also achieved a reasonable history match for the area of the East Flank currently being depleted. The Board agrees with the Proponent that additional work is required to history match the pressure response of the L-98 4 and G-90 2W wells for the period following the initiation of injection, and also concurs with the Proponent that the under prediction of pressure will not affect the conclusion of the simulation study. It is the Board's view that the L-98 4 and G-90 2W pressure data suggest the reservoir is responding better than predicted by the model.

The Board used the available production and pressure data to conduct a material balance assessment to determine original oil in place. A comparison of the Board's original oil-in-place estimates determined from material balance and that determined by the Proponent following the history match, is shown in Table 2.5. The Board believes that its estimate of original oil-in-place for the C09SW block may be high due to oil leakage into this fault block from adjacent blocks. This analysis suggests that the estimates determined by the Proponent are reasonable.

Table 2.5
Comparison of C-NOPB's Material Balance and Proponent's Reservoir Simulation History Match Original Oil-in-Place Estimates

Fault Blocks	Original Oil-in-Place (Millions M^3)	
	C-NOPB	Proponent
C09SW	20	15.10
C09SE and K07	27	30.47
H99C2, H99C3 and H99S	40	40.37

The Board also conducted a volumetric assessment of the original oil-in-place using the Proponent's geological framework, extracted from the Eclipse model and imported into Petrel, a 3D earth modeling software package. A comparison of Proponent's and the Board's original oil-in-place estimates is shown in Table 2.6. While there are slight variations, overall there is good agreement between the Board's and the Proponent's estimates using the same model. The larger differences between the two determinations in the Far East blocks are mainly due to gross rock volume differences caused by a different eastern edge defined in the Board's model. The oil-in-place estimate presented by the Proponent for the Graben and Far East is significantly greater than the estimate of 66 $10^6 m^3$ and 46 $10^6 m^3$ presented in the original development plan. However, for the East Flank, the oil-in-place estimate presented by the Proponent is less than the estimate of 78 $10^6 m^3$ presented in the original Development Plan.

The Board acquired the Proponent's reservoir simulation model and the Board used its reservoir simulation software to run and analyze the model results. While the Proponent examined peak rates up to 39 750 m^3/d, the information provided by the Proponent indicated that the reservoir could only sustain these rates for a short time. This is also true for peak oil rates of 31 800 m^3/d and 27 820 m^3/d. The Board also acknowledges the sensitivity studies conducted to assess the impact of individual well rates on oil recovery and to the miscible process. Based on this review, the Board concurs with the Proponent that these studies support the Proponent's view that oil recovery from the Terra Nova field is not sensitive to peak rates evaluated. Also, at the rates examined in the compositional model rate sensitivity studies, there is no impact on the miscible process.

Table 2.6
Comparison of C-NOPB's and Proponent's Volumetric Original Oil-in-Place Estimates

Area and Fault Block	**Original Oil –in-Place Estimates (Million M^3)**	
	C-NOPB	**Proponent's Mapped Volume (Table 2.1 Supplement)**
Graben		
K07	16.510	16.594
C09SW	15.033	15.096
C09SC	28.029	15.722
C09SE	Included in C09SC	13.439
C09NW	12.375	12.750
C09NC	2.896	3.385
C09NE	9.711	9.736
NGS1	1.528	1.633
NGS2	.0815	0.093
NGS3	3.904	1.126
NGC1	2.206	2.498
NGC2	.0007	0.009
NGC3	4.005	4.344
NGN1	.889	0.027
NGN2	Included in NGN1	
NGN3	Included in NGN1	0.896
Sub Total Graben	**97.178**	**97.348**
East Flank		
H99N	5.718	6.300
H99C1	7.928	8.127
H99C2	19.635	19.567
H99C3	18.320	14.502
H99S	6.505	6.302
I97	2.248	2.399
Attic	6.205	7.446
Sub Total East Flank	**66.559**	**64.643**
Far East		
Horst	4.700	5.270
FES1	.034	0.034
FEE2	40.22	1.018
FEC4	Included in FEE2	1.823
FEE1	Included in FEE2	12.641
FEC3	Included in FEE2	8.363
FEC2	Included in FEE2	8.206
FEC1	Included in FEE2	13.672
FEN1	9.080	10.479
FEN2	Included in FEN1	6.059
FEN3	13.25	14.956
Sub Total Far East	**67.284**	**82.521**
Total Graben /East Flank	**163.737**	**161.988**
Total Graben/East Flank /Far East	**231.021**	**244.512**

With respect to the Proponent’s request to increase the annual oil production rate to 31 800 m^3/d, the model studies support the view that oil recovery will not be adversely affected; there are no waste issues. The reservoir simulation model is an important tool to assess the reservoir performance and optimize depletion schemes to maximize recovery. However, the model is only as good as the data used to construct it, and it is important that a comprehensive data set be acquired to verify the reliability of the model and to update the model. The production data to assess fluid movement through the various sandstone intervals and across faults should be acquired early. With higher production rates, this becomes more important as the displacement process is occurring more quickly. The Board believes that a robust data acquisition program is necessary to obtain information in a timely manner to monitor the water and gas floods and to update the reservoir simulation models. This includes running production logs in selected development wells to assess inflow performance of the various sandstone units, and running appropriate production and saturation logs in development wells following water or gas breakthrough when conditions are such that reliable information can be acquired. It may be possible to acquire information from monitoring performance of producing and injection wells and wireline pressures acquired from newly drilled development wells.

While there are uncertainties surrounding the geological interpretation, communication between sandstone units and across faults and oil-in-place estimates, these are not unusual for most field developments. As additional wells are drilled and production data acquired, these will be resolved. The Board believes that these issues may affect the number of wells and sidetracks required to deplete the oil reserves, and the Proponent’s ability to maintain production rates. The uncertainties are not expected to alter the conclusions of the Proponent respecting rate sensitivities. The Board notes that the Terra Nova field production performance, in terms of the stability of the oil processing facilities and performance of the reservoir, since production was initiated on January 20, 2002, has exceeded expectation. While there is uncertainty, overall the oil-in-place estimates have been within previous predictions. The production information acquired to date demonstrates good connectivity in the fault blocks with producing wells.

2.3.3 Annual Oil Production Rate Increase Request

The Proponent has requested an increase in the annual oil rate from 16 000 to 31 800 m^3/d. Figure 2.10 shows the annual oil production rate forecast for each of the rate sensitivities evaluated by the Proponent for the Graben and East Flank development, while Figure 2.11 provides the same information for the Graben, East Flank and Far East development. From the information provided, an annual oil production rate of 31 800 m^3/d appears to be the reservoir production capacity limit. To achieve this rate, the process facilities must be capable of producing in excess of 31 800 m^3/d to account for down time. The capacity of the production facilities is expected to be less than 31 800 m^3/d. The Proponent is assessing the production capacity of the production facilities. A capacity test was conducted in July 2002 which demonstrated that the production capacity of the oil and gas processing facilities is in excess of 23 800 m^3/d. Based on this information, the Board's Chief Safety Officer approved an increase in the maximum safety related capacity to 23 800 m^3/d subject to concurrence of the certifying authority.

Figure 2.10 Terra Nova Graben / East Flank Average Daily Production Rates

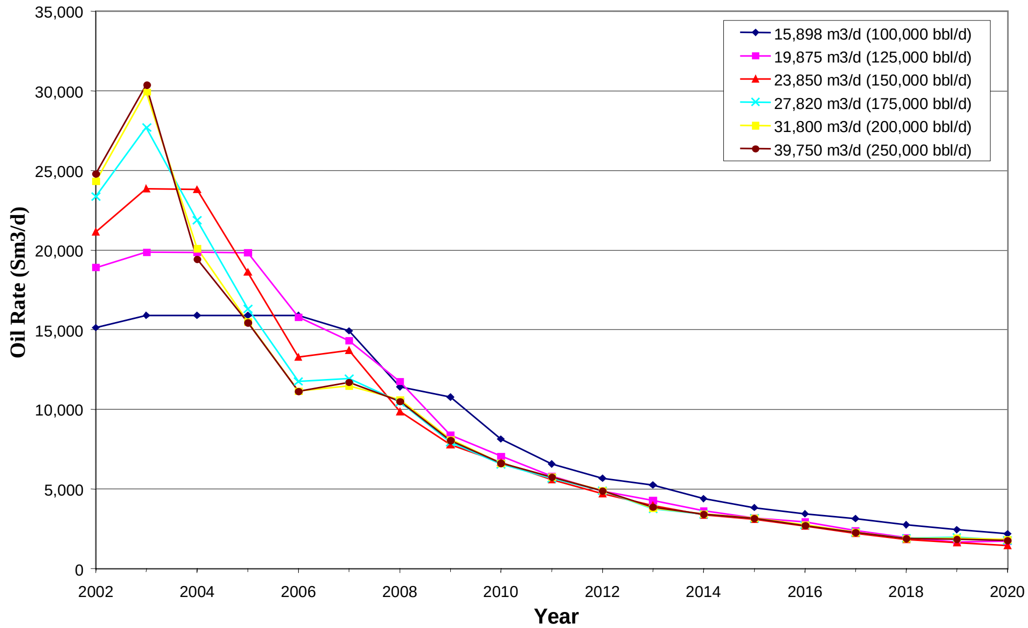
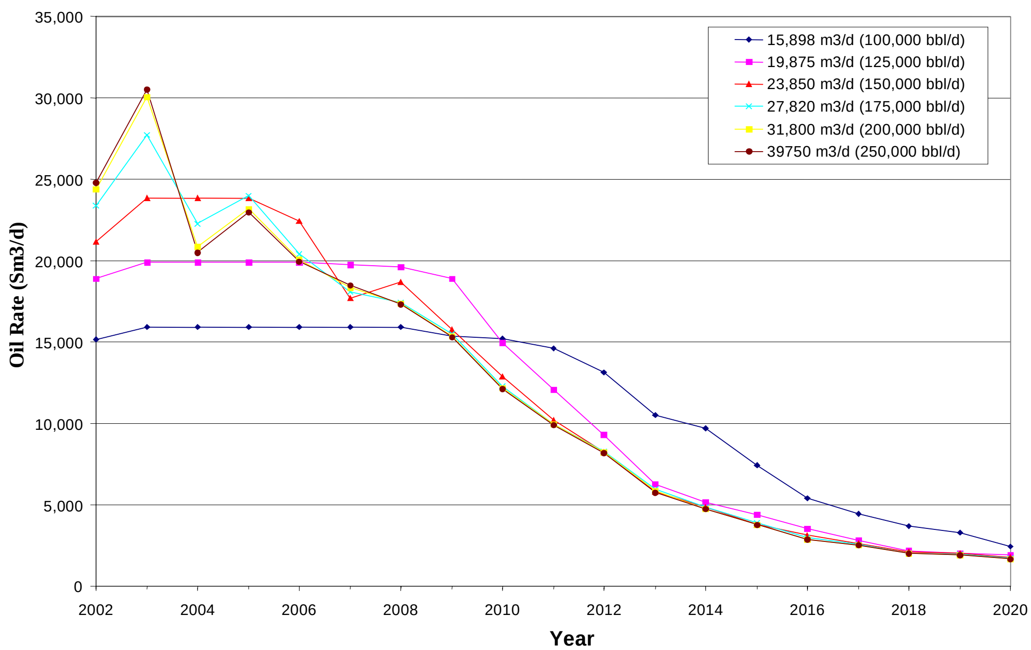


Figure 2.11: Terra Nova Full Field Graben, East Flank and Far East Average Daily Production Rates



Further testing beyond 23 800 m^3/d is planned to determine the facilities processing capacity and identify opportunities to increase the production capacity of the facilities

Based on the information presented, the Board accepts that oil recovery from the Terra Nova Field is not adversely affected by peak oil rates up to 39 750 m^3/d. However, in this case, the production facilities are not capable of operating at this rate or the requested rate of 31 800 m^3/d. Production from the Terra Nova field is restricted by the facility limitation as opposed to being limited by the reservoir performance. The Proponent has established that the production capacity of the processing facilities is in excess of 23 800 m^3/d. A further test is planned to assess the limitation of the processing facilities and identify opportunities to increase the production capacity of the facilities.

The Board observes other factors may present a challenge to achieving the requested production rate. These factors include drilling problems which could lead to development wells not being available in a timely manner, reduced well productivity or injectivity caused by unexpected reservoir conditions or problems encountered during completion or operation of the wells, and unexpected problems with components of the production system. These are typical challenges faced by all developments.

2.3.4 Status of Board's Requirements

In its review of the Proponent's initial request to increase the annual oil production rate, the Board noted that prior to permitting production at the proposed rate, the following is required:

1. The reservoir simulation study conducted to assess rate sensitivity be updated to include production data and new geological data and the results submitted to the Chief Conservation Officer. It was recommended that at least six months of production data should be included in the simulation update.

2. Demonstration of stable operation of the oil and gas processing and injection systems.

3. Testing of the processing facilities, in accordance with a program approved by the Board's Chief Safety Officer and Chief Conservation Officer, to establish the capacity of the facilities.

4. The Chief Conservation Officer be satisfied that the metering and flow calculation and allocation system is functioning properly and providing reasonable accuracy for reservoir management and fiscal purposes.

5. The Chief Safety Officer is satisfied that safety issues are adequately addressed

The Board's Chief Conservation Officer believes the Proponent has adequately addressed the reservoir simulation study.

In respect of the stable operation of the oil and gas processing and injection systems, the oil processing system has been operationally stable. There were problems with the low pressure gas compression system. However, part of the system was functioning prior to the August 2002 planned maintenance shutdown. Other parts of the gas compression system which processes most of the injection gas, were stable prior to shut down. Following shut down, several problems were encountered with the gas injection system, which resulted in the system being out of service for most of September. The Board requires stable operation of this system prior to producing beyond the current approved rates. As noted earlier, one capacity test was conducted, and a second test is approved. This test will be initiated once stable operation of the gas injection system is achieved.

With respect to the measurement system, most elements of this system are working well. There were problems with the gas flare and gas injection meters, which have been fixed. The allocation procedures and subsea components of the measurement system used at the Terra Nova field are a novel approach. A third-party audit of the procedures and meters was conducted prior to the FPSO sailing to the Terra Nova field, and a field audit is scheduled for October 2002. A report detailing the results of the audit will be submitted to the Board's Chief Conservation Officer.

The Board's Chief Safety Officer continues to monitor all safety aspects and has increased the maximum safety related capacity to 23 800 m^3/d. This capacity will likely be increased further depending on the results of the second capacity test.

2.3.5 Impact on Life of Field

In assessing the requested production rate increase, a further consideration is the impact on the life of the Terra Nova field.

The estimate of the impact of a production rate increase on the ultimate life of field for a large offshore oilfield development is a very inexact science. It is based on computer simulation and many variables come into play, including:

- refinement of oil-in-place estimates and recovery factors as more information on the reservoir becomes available through development drilling and well performance;
- improvement in the recovery from advances in drilling technology and oilfield management techniques over the life of the project;
- the price of oil toward the end of the field life will significantly impact when the economic limit of production is reached; and,
- tie-in of other pools or fields which may be found in sufficient proximity to permit production from the existing platform.

As a general rule, in the large offshore field developments of the world, these factors have combined to result in a significantly longer life of field than estimated at the time the projects were approved for development.

For the Terra Nova project, Figures 2.12 and 2.13 show the projected life of field for the original Development Plan Approval rate of 16 000 m^3/d (100,600 b/d) and at the maximum requested rate of 31 800 m3/d (200,000 b/d) based on partial and full field depletion scenarios.

The graphs show:

- at 31 800 m3/d (200,000 b/d)the period during which peak production can be sustained is very short; and,.

- at the end of the production curve, there is no significant difference in the rate at which oil is being produced in either case.

It is clear the affect on life of field resulting from the production rate increase is minimal. Given the significant improvement in the economic return to both owners and governments from the higher level of peak production in the early years, the Board's view is that the production rate increase should be approved.

Figure 2.12: Terra Nova Graben / East Flank Annual Average Daily Production Rates vs. Time

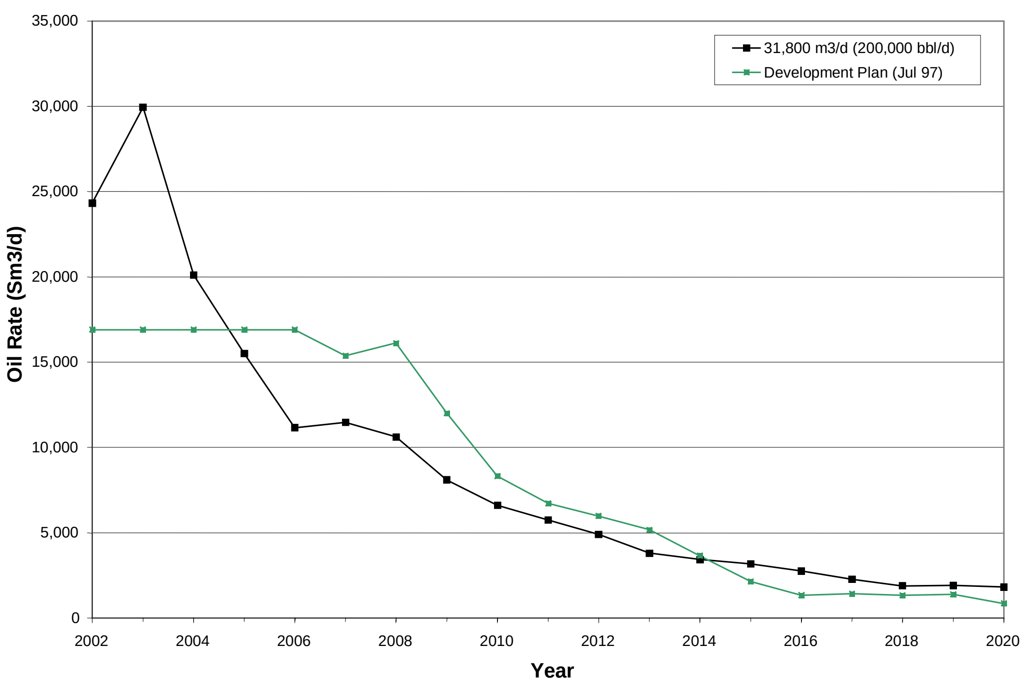
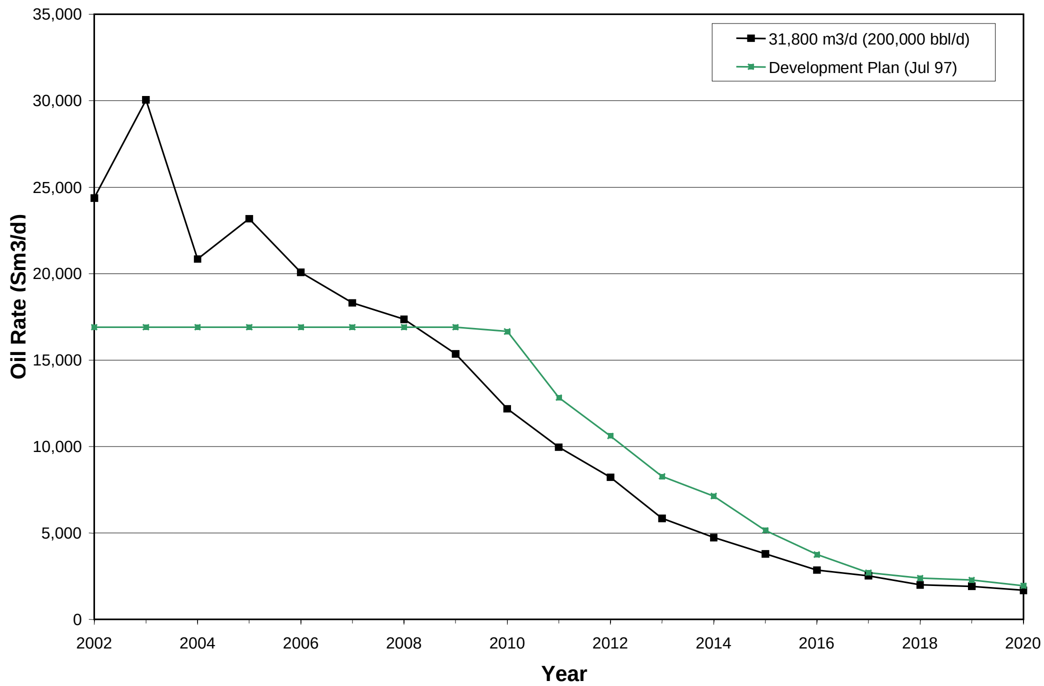


Figure 2.13: Terra Nova Full Field Annual Average Daily Production Rates vs. Time



2.3.6 Facility Capacity

As identified previously in this report, the Board's Chief Safety Officer has approved a maximum safety related capacity for the Terra Nova FPSO at 23 800 m^3/d (150,000 b/d). A further testing program has been approved to determine if the MSRC can be increased beyond this level. Based on their experience to date, the Proponent is projecting the facility may have an ultimate capacity in the vicinity of 26 200 m^3/d (165,000 b/d).

In order to increase the production capacity to 31 800 m^3/d (200,000 b/d), it is the Board's view a significant capital investment would be required on the FPSO, in which case a further amendment to the Development Plan would be required.

3. Conclusion

Terra Nova Development Plan Amendment
Decision 2002.01

The Board approves the Proponent's Application to increase the annual oil production rate up to 31 800 m^3/d (200,000 b/d) subject to the conditions 2002.01.01, 2002.01.02 and 2002.01.03 set out below, and the conditions contained in its Decision Report 97.02. The outstanding conditions are summarized in Appendix 3.

Under this approval, the maximum allowable annual oil production for the calendar year 2002 will be determined using the following daily average oil rates:

a) 16 000 m^3/d (100,600 b/d) from January 1, 2002 to the day immediately preceding the day upon which the Board's approval for an increase to the annual oil production rate becomes effective pursuant to Section 32 of the Acts; and,

b) the annual oil production rate of 23 800 m^3/d (150,000 b/d) from the date of the Board's approval for an increase to that rate becomes effective pursuant to Section 32 of the Acts.

For each calendar year thereafter, the maximum annual oil production rate shall be 23 800 m^3/d (150,000 b/d), or such other rate as shall have been approved by the Board considering appropriate regulatory, administrative and technical criteria. The Board may increase the annual oil production rate up to a maximum of 31 800 m^3/d (200,000 b/d).

Condition 2002.01.01
It is a condition of the Board's approval that:

> Prior to producing oil at a rate above 19 900 m^3/d (125,000 b/d) on a monthly basis, the Proponent must satisfy the Board's Chief Conservation Officer of the following:
> a) Stable operation of the gas injection system, and
> b) That the metering and flow calculations and allocation system is functioning properly and providing reasonable accuracy for reservoir management and fiscal purposes.

Condition 2002.01.02
It is a condition of the Board's approval that:

> 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.

Condition 2002.01.03

It is a condition of the Board's approval that:

> 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.

Appendix 1
Board's Review of January 2000 Application

Appendix 1
Board's Review of Application January 2000

In support of the production rate increase application submitted on January 12, 2000, the Proponent conducted reservoir simulation studies to assess the impact of the proposed production rate on oil recovery. The information from nine wells, Figure 1, drilled in the Terra Nova Field was used to construct geological models. According to the Proponent, five major and two minor oil bearing sands were encountered in these wells. Further, the Proponent notes that due to the complex nature of the Jeanne d'Arc reservoir, and relatively sparse well control, numerous geological and geophysical models and concepts have been put forward.

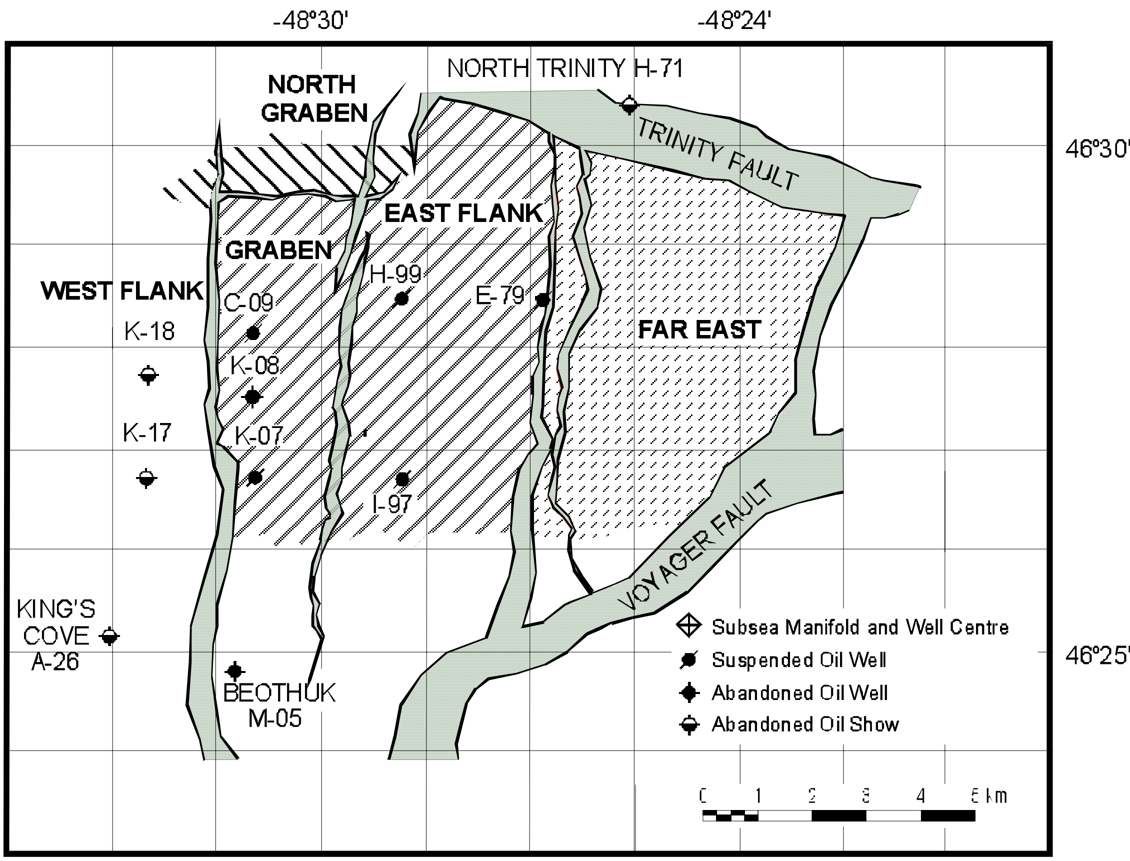


Figure 1: Terra Nova Field Outline

Source: after Petro-Canada, 1997

The Proponent used the alternative 1 geological model presented in the "Reservoir Basis for Terra Nova Development " submitted to the Board in March 1998 as the base case. This model consists of 13 layers, seven sandstone and six shale. The five main sandstone layers were further divided into four to six sub-layers. A 28-layer reservoir simulation model was constructed which included the mapped faults and accounted for faults that were beyond the resolution of seismic. Among other factors, the model provided for vertical communication between the sandstone layers and lateral communication across the faults where the sandstone layers were adjacent. According to the Proponent, a vertical to horizontal permeability ratio of 0.02 was used throughout the model. Also, where sand-to-sand contact is interpreted to exist across a fault, a transmissibility factor of 0.0002 was used. Both these factors were based on well test results from the H-99 well DST 1 and E-79 well DST 3 respectively.

According to the Proponent, the experimental pressure volume and temperature tests conducted on fluid samples acquired from wells in the Terra Nova field, indicate the presence of three distinct oil types. The three oil types were used in the reservoir simulation model. The Proponent notes that a single equation of state model was used to characterize all of the Terra Nova Fluids. A summary of pertinent properties of the three oil types is provided in Table 1.

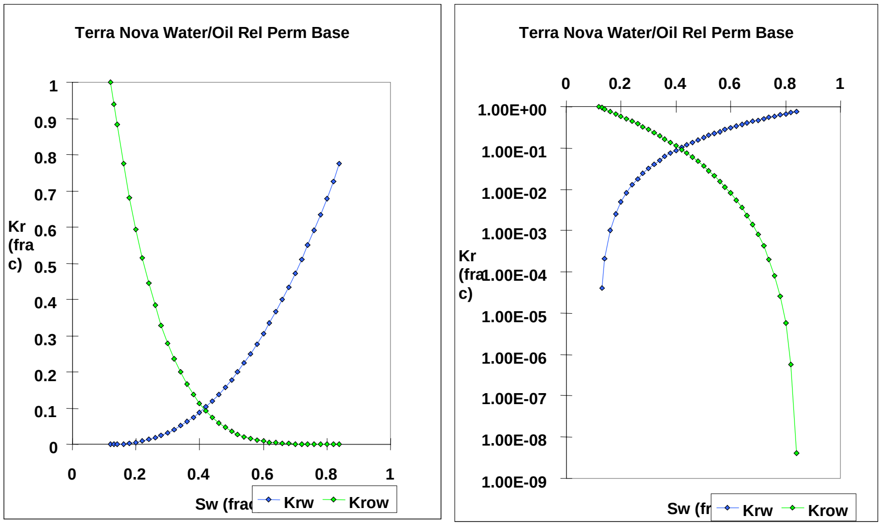
The Proponent presented the oil-water and gas-oil relative permeability curves used in the reservoir simulation model. These curves are shown in Figure 2. According to the Proponent, except for a non-representative oil-water contact encountered in the Terra Nova K-08 well, neither a gas-oil nor oil-water contact has been identified from the drilling results. Based on data acquired from wells drilled in the area, an oil-water contact 3548 ± 33 metres subsea has been postulated. An oil-water contact of 3515 metres subsea has been used for the base case model.

For the reservoir simulation model, the Proponent initialized three equilibration regions corresponding with the three fluid types identified. The solution gas-oil-ratio was varied with depth. The original-oil-in-place in the simulation model for the C-09, K-07, I-97 and H-99 fault blocks and each of the seven sandstone layers, was matched to the reference case geological model. According to the Proponent, the original-oil-in-place in the Graben and East Flank was 150 x 10^6 m^3, and for the entire Terra Nova Field was 208 x 10^6 m^3. The Graben and East Flank were the only areas modeled.

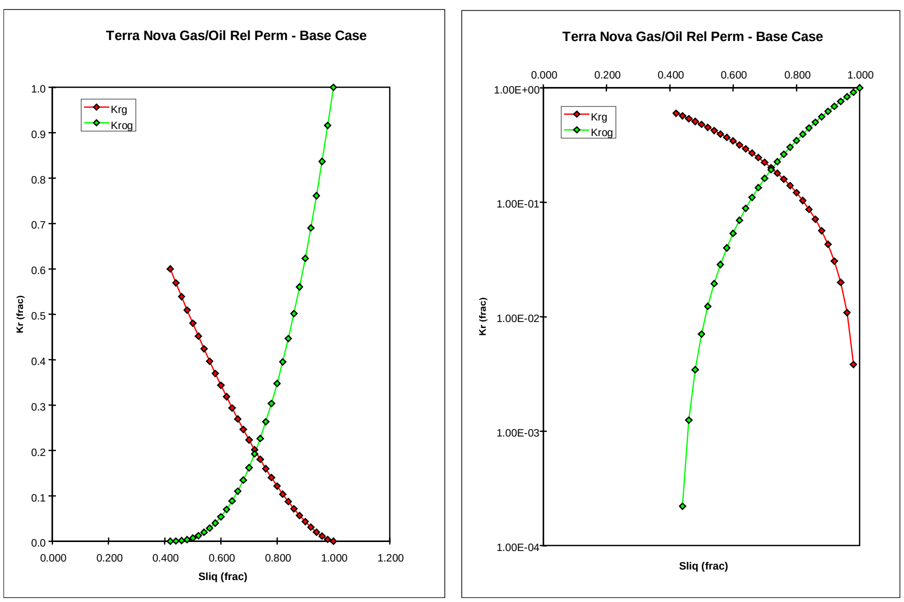
The Proponent noted the base case depletion strategy was as previously submitted for the Terra Nova Development Plan. This strategy provides for a waterflood scheme to be used to exploit the East Flank and Graben K-07 fault block, and a gasflood scheme in the Graben C-09 fault block. In the event there is insufficient gas, water may be injected into the C-09 to maintain voidage. Twenty-five wells, 15 producers and 10 injectors, are expected to be required to deplete the oil reserves. The Proponent imposed several field and well production constraints and limits. These are summarized in Table 2.

Table 1 Terra Nova PVT				
Property		**PVT Region**		
		1	**2**	**3**
Mean Depth	Mss	3364	3417	3289
Reservoir Pressure (Pres)	Bar	354.60	355.00	347.50
Bubble Point Pressure (Pb)	Bar	247.25	259.59	221.04
Reservoir Temperature	C	100	101	97
Oil Formation Volume Factor @ Pres	M^3/m^3	1.322	1.351	1.295
Oil Formation Volume Factor @ Pb	M^3/m^3	1.350	1.378	1.327
Gas Formation Volume Factor @ Pres	M^3/m^3	0.00354	0.00356	0.00359
Gas Formation Volume Factor @ Pb	M^3/m^3	0.00455	0.00442	0.00507
Water Formation Volume Factor @ Pres	M^3/m^3	1.031	1.031	1.031
Solution Gas Oil Ratio	M^3/m^3	136.76	148.02	125.33
		(139*)	(150*)	(127*)
Oil Density @ Pres	Kg/m^3	734.15	724.62	740.22
Oil Density @ Pb	Kg/m^3	718.84	710.45	722.29
Oil Density @ ST	Kg/m^3	862.02	861.76	860.14
Gas Density @ Pres	Kg/m^3	242.47	188.65	256.22
Gas Density @ Pb	Kg/m^3	260.26	209.62	181.43
Gas gravity		0.761	0.761	0.752
Water Density @ ST	Kg/m^3	1020	1020	1020
Zgas				
Oil Viscosity @ Pres	Cp	0.55	0.503	0.652
Oil Viscosity @ Pb	Cp	0.458	0.425	0.52
Gas Viscosity @ Pres	Cp	0.0248	0.0248	0.0227
Gas Viscosity @ Pb	Cp	0.0203	0.0208	0.0181
Water Viscosity @ Pres	Cp	0.32	0.32	0.32

(*)Calculated GOR based on HYSIM simulation package.



Kro'	1.000	Corey-oil	4.5
Krw'	0.800	Cory-wat	2.3
Swi	0.12		
Sorw	0.15		



Kro'	1.000	Corey-oil	2.5
Krg'	0.600	Cory-gas	1.5
Swi	0.12		
Sorg	0.30		

Figure 2: Oil-Water and Gas-Oil Relative Permeability Curves

Table 2 **Field and Well Production Constraints and Limits**	
Well Type	**Well Limit**
East Flank Horizontal Wells	5000 m^3/d liquid, minimum bottom hole pressure 23.0 Mpa
East Flank Vertical Wells	3000 m^3/d liquid, minimum bottom hole pressure 23.0 Mpa
Graben Horizontal Wells	4000 m^3/d liquid, minimum bottom hole pressure 25.0 Mpa
Graben Vertical Wells	5000 m^3/d liquid, minimum bottom hole pressure 25.0 Mpa
Water Injectors	9000 m^3/d
Gas Injectors	4 $10^6 m^3$/d gas, maximum tubing head pressure 34 MPa with lift curve

The technical cutoff limits used by the Proponent to stop production from a well are presented in Table 3.

Table 3 **Cutoff Limits for Producing Wells**			
	GOR (m3/m3)	Oil rate (m3/d)	% Watercut
Vertical Wells	3000	15	90
Horizontal Wells	3000	200	90

To assess the effect of the field average peak oil rate on ultimate oil recovery, the Proponent ran three rate sensitivity cases. These were 16 000 m^3/d (100,000 b/d), which is the current approved field peak oil production rate, 23 850 m^3/d (150,000 b/d), which is the average field rate being applied for, and 31 800 m^3/d (200,000 b/d). The Proponent notes that the production facility design limits were 19 900 m^3/d oil (125,000 bopd) and 45 300 m^3/d liquid (285,000 b/d), expandable to 50 800 m^3/d (320,000 b/d) with the addition of a second separator. Gas production and injection facility limits used in the simulation are 8.37 $10^6 m^3$/d and 7.49 $10^6 m^3$/d, respectively. For simulation purposes, the base case, 16 000 m^3/d (100,000 b/d), used 40 000 m^3/d liquid limit (250,000 b/d), while the other cases used 45 300 m^3/d liquid limit (285,000 b/d).

According to the Proponent, the reservoir simulation studies indicated that the ultimate oil recovery factor was not rate sensitive for the cases investigated. A summary of the results is presented in Table 4.

Table 4
Terra Nova Average Peak Oil Rate Sensitivities

Average Peak Oil Rate m^3/d	Years	Field Recovery Factor	Field Reserves 10^3m^3	Graben Recovery Factor	East Flank Recovery Factor	Field Oil Rate m^3/d	Field Water Cut Fraction	Field Gas Oil Ratio m^3/m^3
16 000	20	0.398	59 809	0.382	0.411	1 055	0.58	1 344
23 850	20	0.402	60 533	0.387	0.417	1 023	0.63	1 136
31 800	20	0.405	60 952	0.390	0.420	1 083	0.63	1 436
Field Original Oil in Place 10^6m^3				151				
Graben Original Oil in Place - 10^6m^3				74				
East Flank Original Oil in Place - 10^6m^3				77				

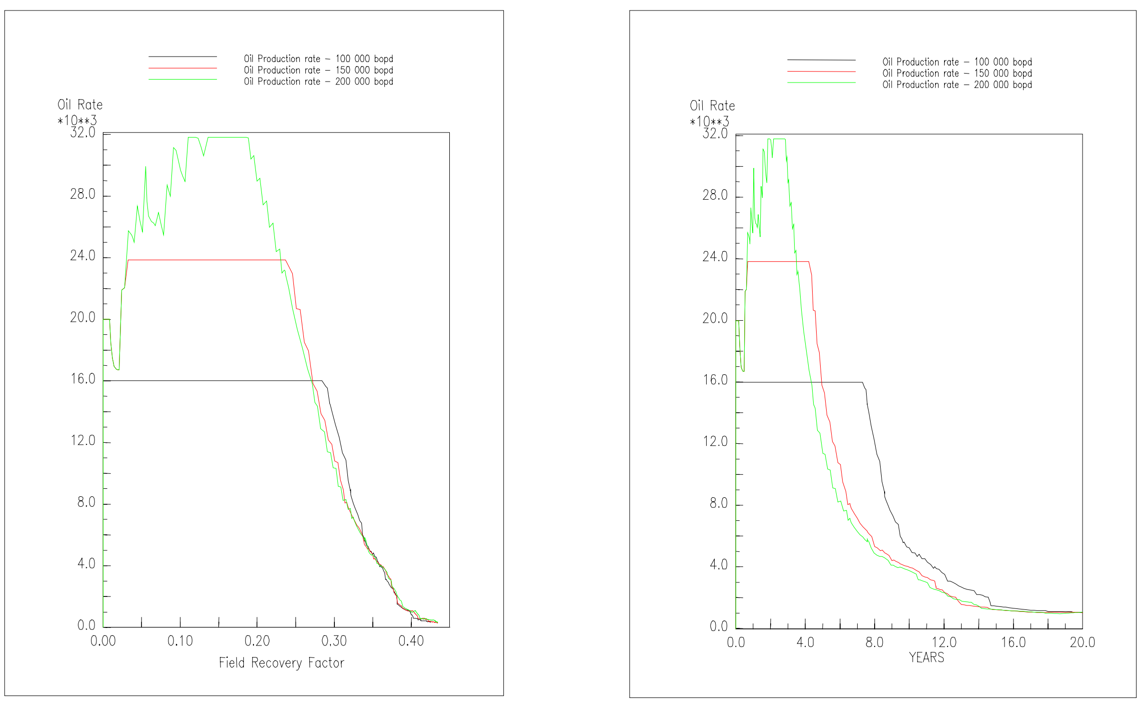


Figure 3: **Base Case Comparison Field Production Performance Verses Recovery Factor and Time**

The Proponent presented a comprehensive set of plots on field, fault block and well bases for each case in support of the application. Plots of field production performance verses recovery factor and time, are provided in Figure 3.

On May 25, 2000, in response to a request from the Board's technical staff, the Proponent submitted a supplement document which presents the results of reservoir simulation studies conducted using an alternate geological model to that used for the development plan base case. According to the Proponent, the alternate model included updated 1997 3D seismic geophysical time and depth structure maps, fault model, internal stratigraphy mapping, deterministic volumes, well correlations, isochores, parameter maps, reservoir characterization simulations, and 3D faulted reservoir model. A comparison of the lithostratigraphic layers for the base case and alternate geological model is shown in Table 5. The Proponent noted that the alternate model is an optimistic model built to capture the potential upside sand distribution to allow optimization of well placement, and to maximize the information obtained from the initial wells. The Proponent reduced the pore volume to match the current most likely reserve estimates distribution presented in the document "Reservoir Basis for Terra Nova Development".

Table 5
New Geological Model
Lithostratigraphic Layers

DPA Correlations	September '98 Geological Model Correlations
E Sand	E Sand
ED Shale	ED Shale
D2 Sand	Dc Sand
D2 Sand	Db Shale
D2 Sand	Da Sand
D2 Sand	D Congl.
D2D1 Shale	UC2 Sand
D1 Sand	UC2 Congl.
D1C2 Shale	LC2 Shale
C2 Sand	LC2 Sand
C2C1 Shale	C2C1 Shale
C1 Sand	C1 Sand
C1 Sand	C1 Congl.
C1B1 Shale	C1B Shale
B1 Sand	B Sand
B2B1 Shale	B Sand
B2 Sand	B Sand
BRank Shale	BRank Shale

In the updated reservoir simulation model study conducted using the alternate geological model, the Proponent constructed two models, one each for the East Flank and the Graben, which were coupled and run to assess the effect on ultimate recovery of various field peak oil rates. Relative permeability data, field and well production constraints and limits, and depletion strategy, were kept the same as that used for the base case study. The Proponent updated the fluid properties to take into account the alternate geological model, process simulation gas/oil ratios, and a separate fluid type, for the East Flank E sand. The cutoff limits for producing wells, shown in table 6, used by the Proponent was increased.

Table 6
Cutoff Limits for Producing Wells

	GOR (m3/m3)	Oil rate (m3/d)	% watercut
Vertical Wells	9000	15	95
Horizontal Wells	9000	200	95

According to the Proponent, the reservoir simulation studies conducted using the alternate geological model indicated that the ultimate oil recovery factor was not rate sensitive for the cases investigated. A summary of the results is presented in Table 7.

Table 7
Terra Nova Average Peak Oil Rate
Sensitivities

Average Peak Oil Rate m^3/d	Years	Field Recovery Factor	Field Reserves 10^3m^3	Graben Recovery Factor	East Flank Recovery Factor	Field Oil Rate m^3/d	Field Water Cut fraction	Field Gas Oil Ratio m^3/m^3
16 000	20	0.358	62 051	0.279	0.400	584	0.944	124
23 850	20	0.357	61 880	0.289	0.401	139	0.938	127
31 800	20	0.359	62 201	0.291	0.401	177	0.951	124
Field Original Oil in Place 10^6m^3				173.48				
Graben Original Oil in Place - 10^6m^3				70.45				
East Flank Original Oil in Place - 10^6m^3				103.03				

The Proponent presented a comprehensive set of plots on a field, fault block and well basis, for each case in support of the application. Plots of field production performance verses recovery factor and time, are provided in Figure 4.

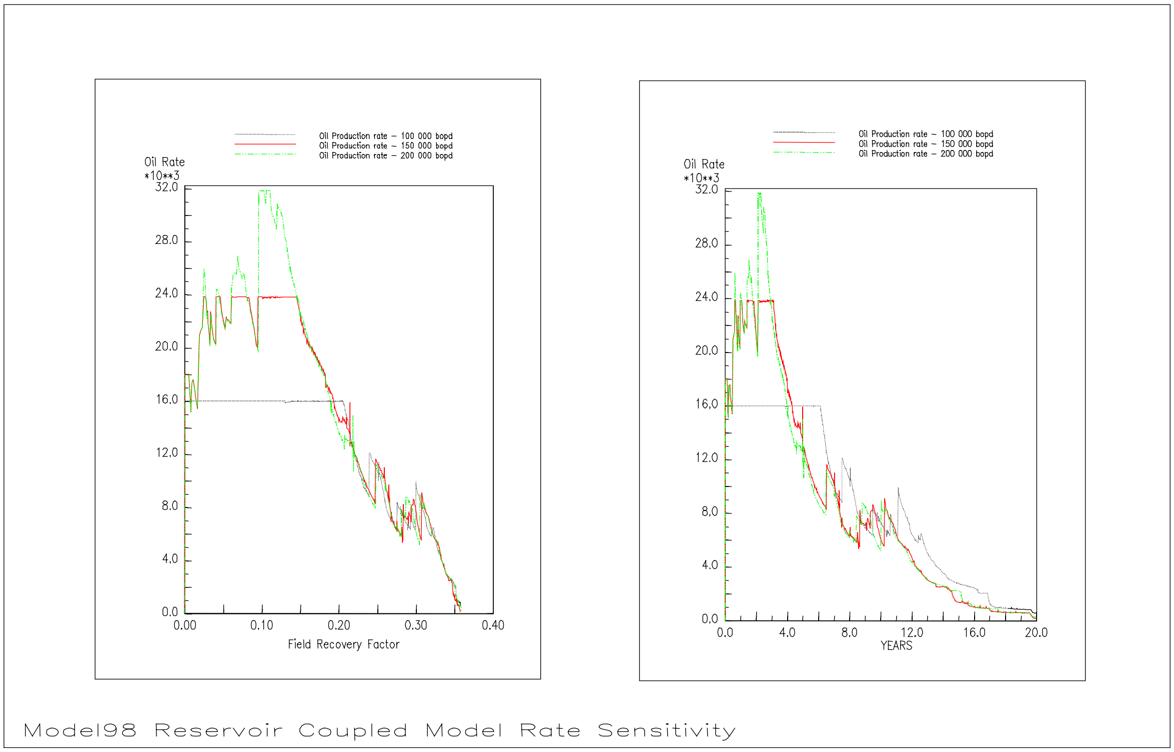


Figure 4: Alternate Case Comparison Field Production Performance Verses Recovery Factor and Time

Board's Review of Proponent's Application January 2000:

The Board reviewed the information submitted in support of the January 12, 2000 application to allow an average annual oil production rate up to 23 850 m^3/d (150,000 b/d), met with the Proponent's representatives to discuss the information, obtained a copy of the reservoir simulation files, ran the reservoir simulation, and reviewed the results using its reservoir simulation software. The Board believes the approach to, and the results of, the reservoir simulation studies conducted by the Proponent to be reasonable based on the models and the facility assumptions used. These studies indicate that the recovery efficiency is not sensitive to the peak production rate. Although a difference in recovery is observed between the two geological models, it is the Board's view that the difference is associated with geological factors. The proposed higher production rate could potentially reduce the field life by about 1 to 2 years. However, care must be exercised with using the simulation forecast to predict when production from the field is likely to end, as, in many cases, the field tends to produce for a longer period than predicted. The areas of concern noted by the Board are the geological model, production facilities performance, and well and reservoir production performance.

The Board reviewed the geological interpretation presented by the Proponent and conducted an examination of the data. The Board agrees with the Proponent that there are several possible geological models with varying sand and shale correlations, that can be reasonably put forward. The Board concluded that the geological model and correlations proposed in the base case and the alternate geological model are reasonable.

The Board also reviewed data acquired from the development wells drilled since the application was submitted, and discussed the data with the Proponent. It is the Board's view that data acquired from development drilling in the Graben did not strongly support any of these models. Since submission of the application, the G-90 2W development well and pilot holes G-90 2 and G-90 2Y have penetrated the Terra Nova reservoir on the East Flank. Data from the two pilot holes confirmed the presence of sandstone units consistent with the geological model. However, the sandstone encountered is tight and non-productive due to calcite cementation. This was not expected. At the time of review of the Proponent's rate increase request, the G-90 2W well was still being drilled. Preliminary data from the well suggest that the tight sandstone extends for some distance. Given the location of the G-90 2W well, in close proximity to the faults, it is not certain if the calcite cement deposition is related to the faulting, or if it is more regional and extends throughout the northern area of the East Flank. The former scenario could have a minor to significant effect on the oil-in-place and reserve estimates, depending on the extent of the calcite cement halo around the faults. Also, the cementation would prevent communication across the faults potentially compartmentalizing the reservoir into many smaller independent fault blocks. The Terra Nova Development plan has provided for this case. If the calcite cementation is regional in nature and exists throughout the northern area of the East Flank, it will have a significant impact on the oil-in-place and reserve estimates for this area.

The Board believes further work and information are required to assess the implications of the calcite cementation. Two wells are scheduled to be drilled in the East Flank area prior to the initiation of production that will assist in determining the extent of the calcite cementation. Also, at the early stages, production data will provide valuable information to assess communication across the faults, geological correlations and models, and well and field performance. The Board believes that prior to issuing any formal approval to increase production to the proposed rate, this information acquired from drilling and producing operations should be assessed, and simulation studies updated to account for this new information.

According to information provided by the Proponent, the production facility design capacity of 19 900 m^3/d (125,000 b/d) has been refined and de-bottlenecked to permit a processing capacity of up to 23 800 m^3/d (150,000 b/d). To achieve the increased processing capacity, the Proponent intends to use the test separator when it is not required for normal testing requirements. Provision is included in the processing facility design to install an additional separator to increase the liquid processing capability by 5 565 m^3/d (35,000 b/d). The production forecast presented by the Proponent assumes that the processing capacity of 23 800 m^3/d (150,000 b/d) will be available 100 per cent of the time. It is the Board's view that this is unlikely, as there will be operational upsets and downtime for maintenance. Therefore, the effective average annual daily oil production rate during peak production is expected to be less than 23 800 m^3/d (150,000 b/d), unless the processing facilities are proven to have a greater capacity than the design capacity, or an additional separator is installed to increase the processing capacity. The capacity of the production facilities and operating efficiency are key elements that will affect the actual production rate achieved. With any new system that is brought into service, a period of time is required to achieve stable operation. During this period, increased gas flaring can be expected. To prevent waste, the Board believes that prior to increasing oil production to the proposed rate, stable operation of the oil and gas processing and gas injection facilities be achieved at the current approved rate. Also, once stable operation is achieved and sufficient wells have been drilled to provide the necessary production capability, testing of the processing facilities should be undertaken to confirm their capacity.

In addition to the processing facilities, the Board believes the metering systems and flow calculation and allocation procedures, are critical to effect proper reservoir management. While these are not addressed within the application, they are under review by the Board as a separate application. The proposed allocation procedures and subsea components of the measurement system are a novel approach. The Board believes it is important that the procedures and systems are demonstrated to be functioning properly prior to permitting production at higher rates.

In conclusion, the Board concurs with the Proponent that based on the geological interpretation and simulation studies presented, the oil recovery from the Terra Nova reservoir is not adversely affected by peak oil production rates up to 31 900 m^3/d (200,000 b/d). However, prior to permitting production at the proposed rate, the Board required the following:

1. The reservoir simulation study conducted to assess rate sensitivity be updated to include production data and new geological data, and the results submitted to the Chief Conservation Officer. It is recommended that at least six months of production data should be included in the simulation update.

2. Demonstration of stable operation of the oil and gas processing and injection systems.

3. Testing of the processing facilities, in accordance with a program approved by the Board's Chief Safety and Chief Conservation Officers, to establish the capacity of the facilities.

4. The Chief Conservation Officer be satisfied that the metering and flow calculation and allocation system is functioning properly and providing reasonable accuracy for reservoir management and fiscal purposes.

5. The Chief Safety Officer is satisfied that safety issues are adequately addressed.

Appendix 2
Wells used
by the Proponent
in support of the
Terra Nova Geological Model

Appendix 2
Wells used by the Proponent in support of the Terra Nova Geological Model

Beothuck M-05
Brent's Cove I-30
King's Cove A-26
Terra Nova C-09-1
Terra Nova C-69
Terra Nova E-79
Terra Nova F-88 1
Terra Nova G-90 1
Terra Nova G-90 2
Terra Nova G-90 2Y
Terra Nova G-90 2W
Terra Nova G-90 3
Terra Nova G-90 4
Terra Nova G-90 5
Terra Nova H-99
Terra Nova I-97
Terra Nova K-07
Terra Nova K-08
Terra Nova K-17
Terra Nova K-18
Terra Nova L-98 1Z
Terra Nova L-98 2
Terra Nova L-98 3
Terra Nova L-98 4
Terra Nova L-98 5
Terra Nova L-98 7
North Trinity H-71

Appendix 3
Decision 97.02
Outstanding Conditions

Appendix 3 Decision 97.02 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 has drilled a well the Terra Nova C-69 1 well in the Far East area of the field, which confirmed the existence of oil. A second well is currently being drilled. An updated exploitation scheme for the Far East must be submitted to the Board by May 10, 2003.

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: Recinded

> 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:

> No submission is anticipated until after the first well is drilled into the North Graben portion of the field.

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 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)

Appendix 4
Glossary

Appendix 4
Glossary

AOPR	Annual Oil Production Rate
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.
bopd	Barrels of oil per day
bpd	Barrels per day
clastic	Pertaining to a rock or sediment composed principally of individual fragments or grains
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
delineation well	A well that is drilled to assess the aerial extent of an accumulation of petroleum
deltaic	Pertaining to, or like a delta
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
FF	Full Field (Graben + East Flank + Far East)
fluvial	Of or pertaining to a river
FMDPR	Facility Maximum Daily Production Rate
FOPR	Field Oil Production Rate (Sm^3/day)
FOPT	Field Oil Production Total (Sm^3)
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
GOPR WF	Group Oil Production Rate from Water Flood portion of field (Sm^3/day)
GOPR GF	Group Oil Production Rate from Gas Flood portion of field (Sm^3/day)
GOPT WF	Group Oil Production Total from Water Flood portion of the field (Sm^3)
GOPT GF	Group Oil Production Total from Gas Flood portion of field (Sm^3)
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
non-associated gas	Gas which is not in contact with oil
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
porous	Used to describe a rock that contains void spaces
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	Husky Oil on behalf of all participating White Rose interest holders. Those White Rose asset owners who are sharing in the predevelopment costs and who have authorized Husky Oil to prepare a Development Application in its capacity as Operator
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
SDA	Significant Discovery Area

SDL	Significant Discovery Licence
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
White Rose Development	"Development" refers to all phases of developing the oil resource, from the decision to proceed with engineering and construction through to producing operations to abandonment of the field
tcf	Trillion cubic feet
topside (or topsides) facilities	The oil- and gas-producing and support equipment located on the top of an offshore structure
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