APPLICATION FOR APPROVAL
OF THE DEVELOPMENT PLAN FOR
NIGLINTGAK FIELD
PROJECT DESCRIPTION

RESERVOIR DATA

3.1.1 3-D DYNAMIC RESERVOIR MODEL

This section describes the information used in developing the 3-D dynamic reservoir model used to forecast gas production and recovery for the Niglintgak field. The Niglintgak field was discovered in 1973 with the drilling of the Shell Niglintgak H-30 well. Five additional exploration and delineation wells were drilled:

- Chevron SOBC Upluk (C-21)
- Shell Kumak (C-58)
- Shell Niglintgak (M-19)
- Shell Niglintgak (B-19)
- Shell Kumak (E-58)

The C-21 and C-58 wells were abandoned immediately after drilling and evaluation. The remaining four wells were tested and suspended, then abandoned in 1996. The C-21 well is interpreted to be in a complex fault zone and its data is not significantly used in the interpretation.

The data obtained from the wells includes:

- cores
- well logs
- drill stem tests (DSTs)
- production tests (PTs)
- fluid analyses

3.1.2 RESERVOIR DESCRIPTION

The stacked sands of the Niglintgak field contain an accumulation of hydrocarbon pools. Hydrocarbon volumes are recorded in the A through R sands and consist of non-associated gas and oil. Only non-associated gas is part of this development, for which the gas-bearing sands are:

- A sand
- C sand
- D sand
- E sand

3.1.2 RESERVOIR DESCRIPTION (cont'd)

- F-G sand
- L-upper sand
- M-upper sand
- M-middle sand
- N sand

The L-upper, M-upper, M-middle and N sands are sometimes referred to as the L, M, N sands, indicating the non-associated gas sands to be developed. The shallow A sand is the primary reservoir in the Niglintgak field. This sand is characterized by:

- high porosity (28%)
- high permeability (average 400 mD)
- high net-to-gross reservoir development

Generally, porosity and permeability decrease as one goes deeper in the reservoir.

3.1.3 WELL TEST DATA

Numerous DSTs and two PTs were conducted in the Niglintgak wells. Table 3-1 summarizes the Niglintgak field well tests for the sands included in the development.

The most extensive testing was done in M-19, where a total of 28 DSTs were run over more than a dozen distinct sands.

Table 3-1: Niglintgak Field Well Gas Zone Tests

Well Name	Test Date	Type of Test Run	Unit	Result	Rate (Mm^3/d)	Rate (MMscf/d)
Shell Niglintgak (H-30)	January 1973	DST 1	E	Gas	0.167	5.9
Shell Niglintgak (M-19)	June 1974	DST 4	A	Gas	0.238	8.4
	June 1974	DST 6	A	Gas	0.235	8.3
	December 1974	DST 11	N	Gas and NGLs	0.232	8.2
	December 1974	DST 13	M-m	Gas and NGLs	0.275	9.7
	December 1974	DST 14	M-u	Gas and NGLs	0.235	8.3
	January 1975	DST 19	L-u	Gas and NGLs	0.476	16.8
	January 1975	DST 28	D	Gas	0.193	6.8
Shell Niglintgak (B-19)	February 1976	DST 17	A	Gas	0.241	8.5
Shell Kumak (E-58)	May 1977	DST 1	A	Gas	0.249	8.8
	May 1977	DST 2	A	Gas	0.238	8.4
	May 1977	PT 1	A	Gas	0.521	18.4
	May 1977	PT 2	A	Gas	0.266	9.4

The most recent and extensive A sand testing program was conducted in well E-58 in 1977. Two DSTs and two production tests were run to quantify the A sand productivity at different rates and drawdown combinations.

Most DSTs were performed as cased and perforated tests. Generally, the tests were short (less than 12 hours) except for the two extended production tests done in E-58. The time lapse between drilling and testing activities ranged from several days to several weeks. Consequently, in some cases, reservoir rock formations were exposed to the drilling fluid for a substantial period of time, reducing the quality of the data recorded.

Although recent pressure transient analysis results show relatively high formation damage with high skin factors for most of the tests, good deliverability was achieved under minimal drawdown. Therefore, deliverability and, subsequently, permeability-thickness of the upper sands is considered to be high. This is confirmed by the exceptionally rapid buildup of pressure registered by pressure gauges in many of the DSTs for the A to E sands.

3.1.3.1 Pressure-Versus-Depth Plots

Pressure versus depth plots are derived from data obtained from formation tests and are used to help determine hydrocarbon-water levels (free water levels) in a reservoir sand. Figure 3-1 shows the pressure versus depth plot for the Niglintgak field.

Data from the pressure-depth plot (see Table 3-2), logs, DSTs and a Monte Carlo simulation of DST pressure equations were used to determine a most likely free water level (see Table 3-3).

3.1.3.2 Temperature-Versus-Depth Plot

The temperature versus depth plot (see Figure 3-2) was compiled from data collected from the well tests. The temperature gradient is about 2.7°C/100 m.

3.1.3.3 In Situ Methane Hydrates

With the low temperature gradient, the possibility of in situ methane hydrates in the A sand reservoir was considered in the H-30 well. The H-30 well was not tested and is structurally higher than the M-19 well. No reservoir hydrates were observed in the M-19 well, with a top A sand of 804 TVD mSS. The DST results indicated a normal test and ruled out hydrates below this depth. A reservoir hydrates study done in 2003 concluded that no methane hydrates were likely at initial reservoir conditions.

3.1.3.4 Core Data Analysis

A total of 485 m of core was taken in the wells drilled by Shell. Niglintgak core measurements consisted of standard routine analyses and a number of special core analyses done on a representative set of samples for several of the hydrocarbon-bearing sands. These included measurements for:

3.1.3.4 Core Data Analysis (cont'd)

- stressed porosity
- capillary pressure
- formation resistivity factors (FRF)
- saturation exponent (n)
- lithological exponent (m)
- Waxman-Smits' cation exchange capacity (Qv)

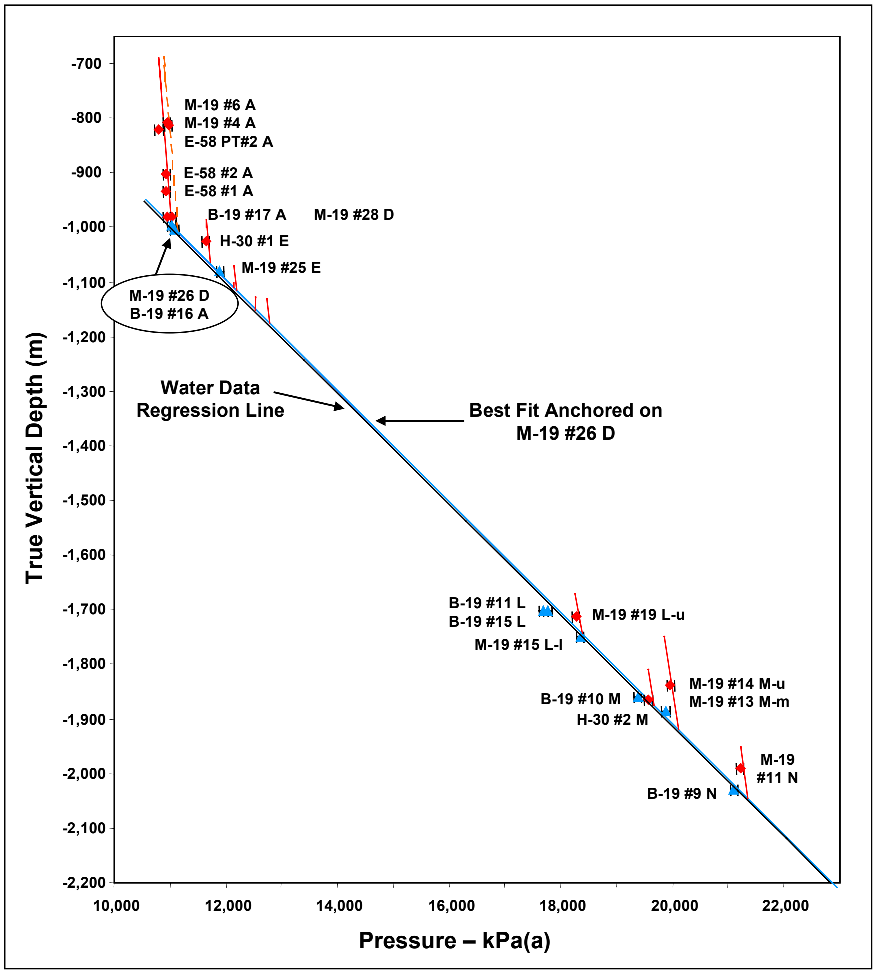

Figure 3-1: Pressure-Versus-Depth Plot for the Niglintgak Field

Core measurements were used to examine the relationship between permeability and porosity (see Section 2.3, Petrophysics).

Capillary pressure measurements done on the Niglintgak core were not considered reliable enough to be used in saturation-height functions, possibly because the measurements were poorly consolidated and measurement techniques for such core in the 1970s lacked precision.

The saturation-height functions were generated using the analytical techniques of Thomeer and Corey-type models based on logs, fluid properties and elevation above the free water level. Seven groups of saturation-height functions, along with their consistent relative permeability functions, were generated on a set of seven permeability bins and were used in the 3-D dynamic reservoir model.

Table 3-2: Pressure and Depth Input Data

Sand	Well	Test Number	Test Interval Start (TVD mSS)	Test Interval Stop (TVD mSS)	Formation Fluid Type	Recorder Depth (TVD mSS)	Extrapolated Fluid Pressure (kPa[a])
A	M-19	4	807	834	Gas	808	10,945
A	M-19	6	807	817	Gas	812	10,973
A	B-19	16	1,001	1,012	Water	1,003	11,086
A	B-19	17	980	988	Gas	979	11,037
A	E-58	1	934	942	Gas	932	10,940
A	E-58	2	903	910	Gas	901	10,940
A	E-58	PT#2	807	834	Gas	821	10,800
D	M-19	26	995	1,001	Mud filtrate	997	11,029
D	M-19	28	977	987	Gas	980	10,946
E	H-30	1	1,039	1,077	Gas	1,026	11,638
E	M-19	25	1,079	1,085	Water	1,081	11,891
L-u	M-19	19	1,710	1,716	Gas	1,713	18,269
L-l	M-19	15	1,748	1,754	Water	1,748	18,345
M-up	M-19	14	1,834	1,841	Gas	1,837	19,962
M-mid	M-19	13	1,851	1,857	Gas	1,864	19,565
M	H-30	2	1,896	2,007	Water	1,886	19,882
M	B-19	10	1,857	1,878	Water	1,858	19,379
N	M-19	11	1,888	1,996	Gas	1,991	21,213
N	B-19	9	2,029	2,033	Water	2,029	21,102
R	B-19	8	2,244	2,252	Water	2,245	23,475

Table 3-3: Niglintgak Estimated Free Water Levels

Sand	Most Likely Free Water Level (TVD mSS)
A, C, D	998
E	1,067
F-G	1,115
L-upper	1,743
M-upper	1,920
M-middle	1,875
N	2,045

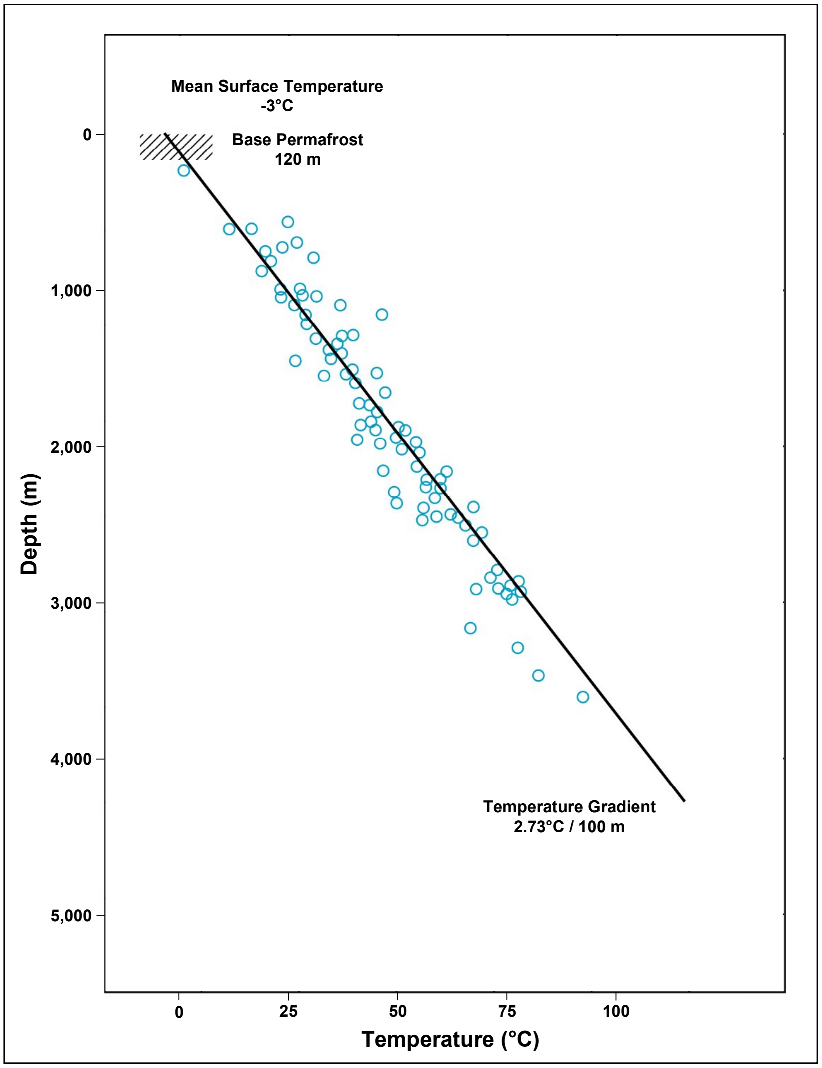

Figure 3-2: Composite Temperature – Depth-Plot Farewell Structure

3.1.4 RESERVOIR FLUID PROPERTIES

Gas analysis of the samples collected during well testing indicated the presence of sweet gas, with over 98% methane in A sand and 95% methane in the L, M and N sands (see Table 3-4). The variation in the methane composition of the gas samples collected from the tested wells (H-30, M-19, B-19 and E-58) was within 1%. Given the various sands tested and test conditions, such variations are not unexpected.

No hydrogen sulphide was observed in the gas analysis.

Natural gas liquids were produced from L, M and N sands during DSTs. The expected average liquid to gas ratio is about 38 m^3/Mm^3 (6.8 bbl/MMscf) from L, M and N sands.

Table 3-4: Expected Reservoir Gas Composition for Niglintgak

Component	Symbol	A Sand (mol%)	L, M and N Sands (mol%)
Hydrogen sulphide	H_2S	0	0
Carbon dioxide	CO_2	0.87	1.5
Nitrogen	N_2	0.13	0.02
Methane	C_1	98.34	95.11
Ethane	C_2	0.61	2.32
Propane	C_3	0.02	0.11
Isobutane	IC_4	0.02	0.12
Normal butane	C_4	0.01	0.03
Isopentane	IC_5	-	0.05
Pentane	C_5	-	0.01
Hexane	C_6	-	0.02
Heptane plus	C_7+	-	0.71
Total		100	100

3.2.1 APPROACH

Two different methods were used to calculate the hydrocarbon resources for each sand layer:

- a probabilistic model
- a 3-D dynamic reservoir model

Both methods generated similar results.

3.2.2 PROBABILISTIC MODELLING

Resources were calculated using a probabilistic model with Shell's proprietary software FASTRACK. The software uses Monte Carlo simulation to calculate a range of potential volumes and the respective probability for each. Data combinations were used to generate 1,000 possible volume estimates for the individual formations.

A risk assessment for undrilled blocks was done using a method consistent with that used in the National Energy Board's *Probabilistic Estimate of the Hydrocarbon Volumes in the Mackenzie Delta and Beaufort Sea Discoveries*, 1998. The analysis yielded a distribution curve of potential volumes in place. The P-90 estimate is a relatively low volume with a 90% probability of being met or exceeded, while the P-10 estimate is at the high end of potential volumes with an estimated 10% probability. The P-50 estimate is the median of volume and probability, and is called the most likely estimate.

Input data for each reservoir included:

- areas from the top reservoir structural map, based on seismic and well control
- an uncertainty area
- hydrocarbon contacts, based on pressure depth plots, DSTs and petrophysical data
- net reservoir thickness, based on geological models, well control and seismic interpretation

3.2.2 PROBABILISTIC MODELLING (cont'd)

- gross reservoir thickness, based on geological models, well control and seismic interpretation
- average porosity, based on core data, well log data and geological models
- average hydrocarbon saturation, based on special core analyses and well log petrophysical evaluations
- formation volume factors, based on compositional analyses
- recovery factors, based on results from dynamic reservoir models
- shrinkage of 7.4% over the field life, based on current development and economic models

For the estimated hydrocarbon resources contained in Shell's SDL 19, see Table 3-5.

Table 3-5: Estimated Hydrocarbon Volumes for SDL 19

Hydrocarbon Volume	Probabilistic Estimate (most likely)
Non-associated gas-initially-in-place	34.0 Gm^3
Non-associated ultimate recoverable gas	25.7 Gm^3
Non-associated marketable gas resources	23.8 Gm^3
Ultimate recoverable NGL resources	0.05 Mm^3