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

INTRODUCTION

4.1.1 APPROACH

The Niglintgak development plan was created through a process that:

- established and modelled reservoir uncertainties
- identified specific development variables and alternatives
- modelled alternatives to establish optimum development concepts

This evaluation process assessed development alternatives using a range of evaluation criteria consistent with Shell's sustainable development commitment and principles.

4.1.2 RESERVOIR SIMULATION

Reservoir simulations were created for 10 different interpretations of the subsurface, called realizations. These realizations are representative of the subsurface uncertainties and varied aspects of the subsurface, such as:

- degree of reservoir layering
- aquifer strength
- extent of faulting
- reservoir rock properties and distribution

The reservoir simulations were used to evaluate the impact on gas resource recovery and well deliverabilities through varying:

- wellbore placement
- number of wells
- downhole wellbore size and equipment
- rock properties
- reservoir parameters
- aquifer strengths

Results from this analysis identified several key characteristics to be considered in optimizing the Niglintgak development plan, including the need for:

- wells drilled high on the crest of the structure to delay water breakthrough and maximize resource recovery

4.1.2 RESERVOIR SIMULATION (cont'd)

- wells to be designed with the ability to isolate zones that might produce water

- sand control to maintain wellbore integrity

- commingled production in some wells to minimize well count

- at least six wells to deplete the resource efficiently

4.1.3 DEVELOPMENT ALTERNATIVES

Further analysis was conducted by combining the results of the reservoir simulations into specific development alternatives. The variables used in developing these alternatives included the:

- physical locations of well pads and the gas conditioning facility
- number of well pads
- number of wells and the complexity of the well design
- flow line configuration
- equipment configuration
- abandonment pressure

One of the key results of assessing development options was well pad placement. Reducing the number of well pads increases the requirement for long-reach wells with high inclinations caused by the shallow depth of the reservoir sands. Long-reach wells of this type:

- increase the likelihood for the suboptimal placing of wellbores in the reservoir, thereby reducing resource recovery

- risk possible wellbore deformation when drilling through fault zones, which could affect the:

  - ability to reach targets cost effectively
  - long-term viability of the wellbore for production purposes

- could increase operating costs because of the complexity of the wellbore path

The evaluation identified the need for three well pads from which to drill wells to reach targets for optimal resource recovery.

4.1.4 RESERVOIR UNCERTAINTIES

With the information from these evaluations, a field development plan was created with sufficient flexibility to ensure reasonable resource recovery for each of the different possible realizations. The six-well development plan obtains reasonable resource recoveries in all but one realization, the faulted case. This case requires a 12-well development to obtain a reasonable resource recovery.

4.1.5 RESERVOIR MONITORING PLAN

Production characteristics of the reservoir from each of the realizations were used to form a well and reservoir monitoring plan. The plan is designed to obtain necessary data that would help predict possible production problems and allow the correct mitigative actions to be taken to optimize resource recovery.

4.2.1 PURPOSE

The purpose of the reservoir simulation was to:

- choose and optimize well placement for the development plan
- assess the number of wells required
- obtain estimates of field production and resource volumes
- test alternative depletion plans
- analyze the impact of geological and reservoir parameter uncertainties

4.2.2 RESERVOIR SIMULATION MODEL

The reservoir simulation model used a geological model of the subsurface (the static model) to predict the flow of subsurface hydrocarbons and water (the dynamic model) into simulated wellbores. The dynamic model tested various arrangements of well placements and their associated production forecasts to choose and optimize the field depletion plan. DEPSIM and MULTISIM, Shell proprietary static and dynamic modelling software, were used.

A detailed 3-D dynamic reservoir model was developed for gas-bearing reservoirs A to N in the Niglintgak field. For the stratigraphy of the Niglintgak field, see Section 2.1, Geological Description. Input into the model included:

- reservoir property maps for the 3-D dynamic reservoir model imported from the 3-D static geological model (DEPSIM) into the reservoir simulator (MULTISIM). The information imported included data for structural elevation, faults, gross thickness, net-to-gross ratios, porosity and permeability maps based on data from the wells described in Section 2, Geology, Geophysics and Petrophysics, and Section 3.1, Reservoir Data.

- capillary pressure and relative permeability curves

- gas and water compositions

An optimized model grid of the gas-bearing area was developed. The 3-D dynamic reservoir model covered an area of about 11 x 11 km, including the entire hydrocarbon area and the surrounding aquifer area. The result was a total of 75,600 model grid blocks.

4.2.2.1 Dynamic Model Initialization

The reservoir dynamic model was initialized with:

- reservoir properties
- well locations with well path deviations
- hydraulic tables

Tubing sizes were optimized to meet the required rate per well. Subsurface safety valves were also considered in the lift curve analysis. Positive skin values of 5 to 10 were modelled, based on engineering estimates of the skin values for each well design and type of completion.

4.2.2.2 Regional Aquifer Model

A 3-D single layer regional aquifer model of the A1 sand was developed to study the impact of aquifer support on Niglintgak reservoir pressure. The 3-D regional aquifer model covered 40 x 26 km, including the Niglintgak, Kumak and Taglu fields. These results were used to model the aquifer support for the chosen case in the field reservoir model.

4.2.3 WATER PRODUCTION

Water production is expected in some wells in the Niglintgak field.

Water from the aquifer will move up the flanks of the field along the laterally continuous reservoir sands. The sands closest to the areas with gas–water contact will produce water first. Areas of high permeability might also result in early water breakthrough. To prevent problems with excess water production, specific water-producing intervals can be isolated. This is known as zonal isolation.

4.2.4 EVALUATION PROCESS

Wells were located to:

- maximize gas recovery
- delay water breakthrough

The evaluation was based on different:

- well patterns
- well spacing
- well production rates
- abandonment tubing head pressures

4.2.5 RESERVOIR SIMULATION RESULTS

The reservoir simulation key assumptions and output results for the chosen development plan included:

- a well pattern of six wells located on the crest of the structure
- a total field raw gas production rate of 4.3 Mm^3/d (150 MMscf/d), allocated as:
    - 3.5 Mm^3/d (121 MMscf/d) from the A sand reservoir (four wells)
    - 0.6 Mm^3/d (22 MMscf/d) from the D, E, and F-G sand reservoirs (one well with commingled production)
    - 0.2 Mm^3/d (7 MMscf/d) from the L, M and N sand reservoirs (one well with commingled production)
- a tubing head abandonment pressure of 1,724 kPa
- compression required from start-up
- an economic production life of about 25 years
- a plateau rate for 13 to 14 years
- a cumulative total gas recovery of about 27 Gm^3
- a cumulative NGL recovery of 0.04 Mm^3

The following forecasts were generated by the reservoir model for the chosen Niglintgak development concept:

- Figure 4-1 – Niglintgak Reservoir Model Raw Gas Forecast
- Figure 4-2 – Niglintgak Reservoir Model Cumulative Raw Gas Forecast
- Figure 4-3 – Niglintgak Reservoir Model Water Production Forecast

These initial reservoir model forecasts do not include availability impacts which, when included, extend the expected production flatlife period. The model output was adjusted to include availability, fuel gas usage and liquids shrinkage to determine the expected sales gas forecast for the development (see Section 5.4, Functional Criteria).

The production forecasts for the Niglintgak field are based on Shell's development on SDL 19, assuming no development on adjacent lands. Future adjacent developments might alter these forecasts.

4.2.6 RESERVOIR UNCERTAINTY ANALYSIS

To assess the impact on gas recovery, possible reservoir uncertainties were identified and have been studied with the 3-D dynamic reservoir model. These uncertainties are related to factors such as:

- fault transmissibility
- aquifer strength
- reservoir connectivity
- gross rock volume variation
- permeability variation
- rock compressibility
- residual gas saturation
- kv/kh ratio (vertical permeability to horizontal permeability ratio)

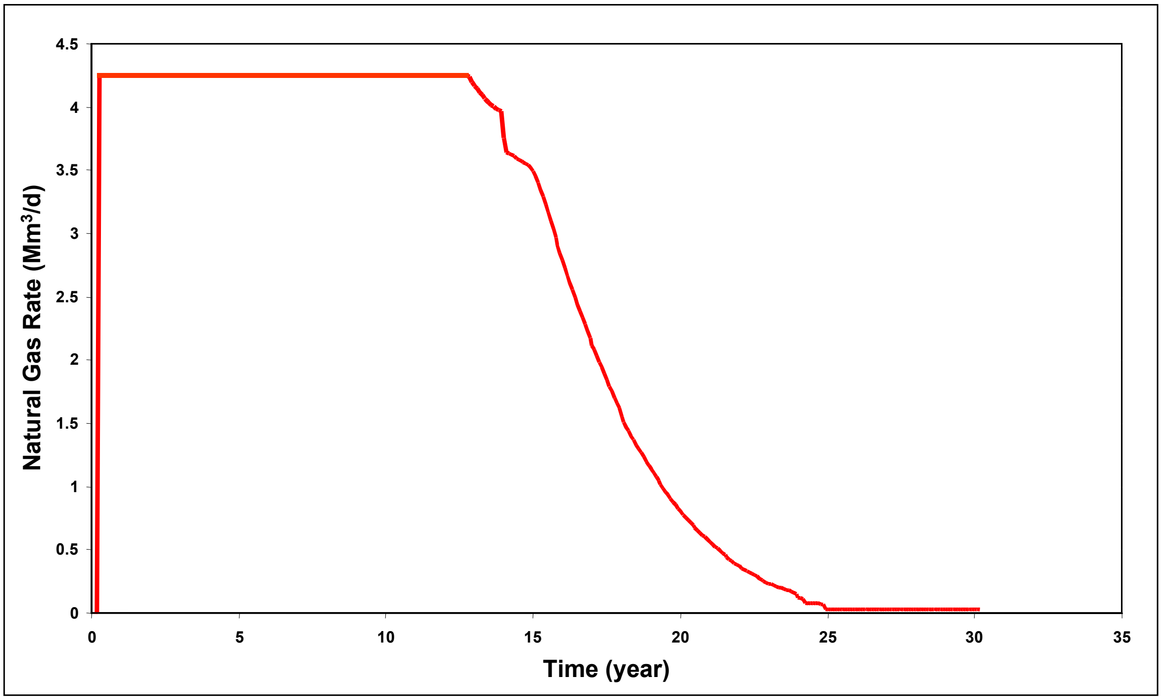

Figure 4-1: Niglintgak Daily Raw Gas Production Forecast

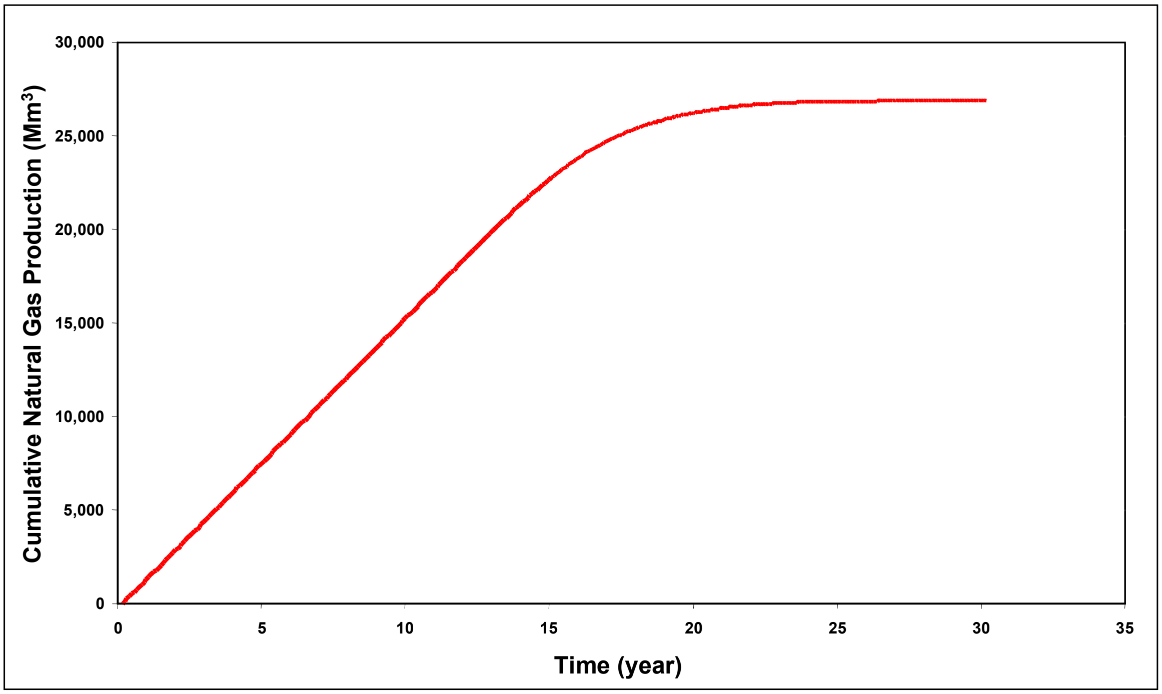

Figure 4-2: Niglintgak Cumulative Natural Gas Production Forecast

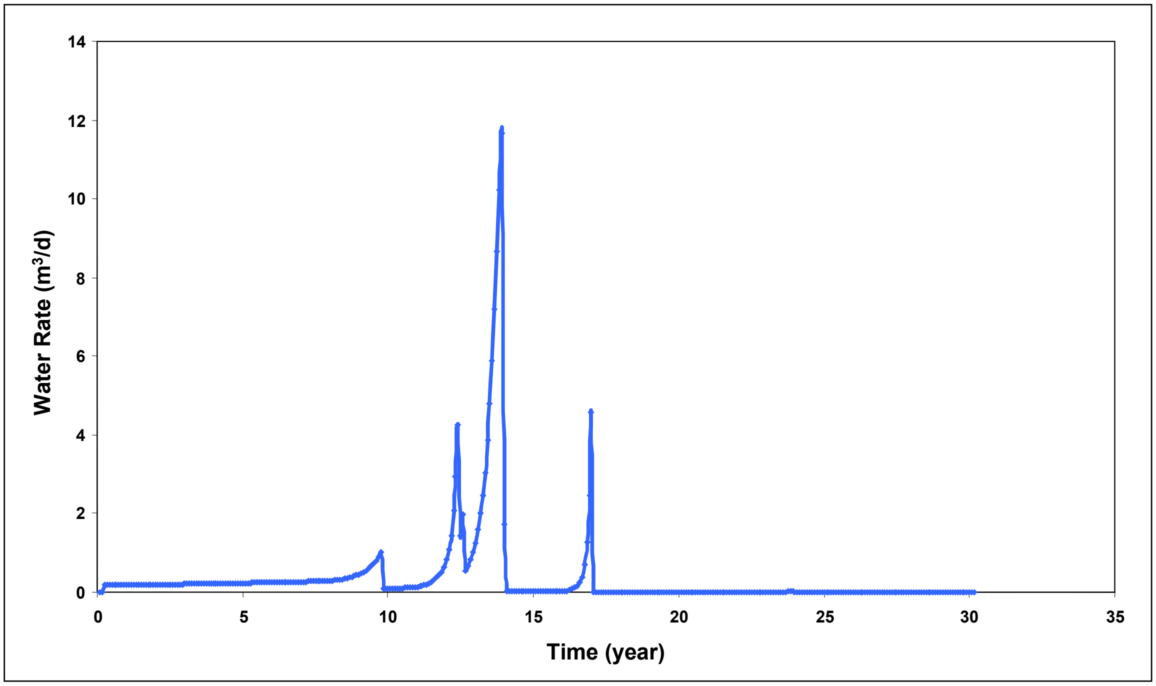

Figure 4-3: Niglintgak Daily Water Production Forecast

4.2.7 A SAND RESERVOIR REALIZATIONS

To study a wide range of reservoir depletion scenarios, 10 subsurface reservoir realizations (R1 and R1.1 to R9) were considered for the A sand, which contains most of the Niglintgak gas resources.

Table 4-1 summarizes the 10 realization cases.

Table 4-1: Summary of Reservoir Realization Cases

Reservoir Realization	Description
R1	Layered reservoir with sealing faults (chosen case)
R1.1	Layered reservoir with transmissible faults
R2	Layered reservoir with a stronger aquifer
R3	Layered reservoir with more sealing faults (faulted case)
R4	Tank reservoir case
R5	Tank reservoir case, with thief zone of high permeability
R6	High GRV/GIIP case
R7	Low GRV/GIIP case
R8	Sweet fairway case - good permeability around wells only
R9	Low permeability case
Note: GRV = gross rock volume GIIP = gas-initially-in-place	

4.2.7 A SAND RESERVOIR REALIZATIONS (cont'd)

Table 4-2 summarizes the results for each realization, based on a six-well development with an initial rate of 4.3 Mm^3/d (150 MMscf/d).

Table 4-2: Ultimate Raw Recoverable Gas and Average Field Production Plateau by Realization Case

Case Number	Case Type	Ultimate Raw Recoverable Resources (Gm^3)	Average Production Plateau Period (Years)
R1	Layered reservoir with sealing faults (chosen case)	26.9	13
R1.1	Layered reservoir with transmissible faults	28.7	15
R2	Layered reservoir with a stronger aquifer	26.1	14
R3	Layered reservoir with more sealing faults (faulted case – 12 wells)	22.7	10
R3	Layered reservoir with more sealing faults (faulted case – six wells)	14.7	3
R4	Tank reservoir case	30.2	16
R5	Tank reservoir case, with thief zone of high permeability	29.2	15
R6	High GRV/GIIP case	31.4	16
R7	Low GRV/GIIP case	21.9	10
R8	Sweet fairway case	24.6	13
R9	Low permeability case	24.4	11
Note: GRV = gross rock volume GIIP = gas-initially-in-place			

With all these realizations, the chosen development plan will have reasonable resource recoveries with the six-well development from the three well pads, except for the faulted case (R3). Analogue fields show that more wells than had originally been planned are sometimes needed because of the compartmentalization of the reservoir caused by subseismic faulting or stratigraphic variability. The R3 faulted realization doubles the number of fault blocks that are seen from seismic. Reasonable recoveries can be achieved by adding additional development wells.

4.2.8 HORIZONTAL WELLS

A horizontal well with a horizontal length of 500 to 600 m was evaluated in both the north and south areas of the field. However, model results indicated that a horizontal well would not add significant value, compared to the planned deviated wells.

4.3.1 ASSESSMENT PROCESS

During the conceptual design phase, Shell considered several options for developing the Niglintgak surface facilities. Consistent with Shell's sustainable development principles, the following criteria were used to evaluate and compare the identified development options:

- environmental impact
- stakeholder impact
- socio-economic impact
- impact on safety
- impact on reliability
- impact on operability
- impact on resource recovery
- capital and operating cost
- future expansion capabilities

The evaluation was completed in two phases:

1. an initial screening to eliminate the least attractive options

2. a more detailed evaluation of the remaining options to assess their relative strengths and weaknesses

In addition to these evaluations, studies were completed by the Mackenzie Gas Project to assess different options of using a common centralized gas conditioning facility for the Niglintgak, Taglu and Parsons Lake fields. These studies concluded that there was no significant technical, economic or environmental advantage to this option.

Table 4-3 briefly describes each of the 10 alternatives considered.

4.3.2 SCREENING ANALYSIS

Many of the Niglintgak development alternatives have common characteristics with the proposed development option. The first phase of evaluation eliminated eight of the development scenarios.

Table 4-3: Niglintgak Development Options

Chosen Development Option	Description
Barge option	• Six wells drilled from three well pads, including: • two well pads on Niglintgak Island • one well pad on the east bank of the Kumak Channel • Gas from island well pads produced through above-ground flow lines and under the Kumak Channel to the barge-based processing facility • Processing at gas conditioning facilities located on a foundation in the Kumak Channel
Alternative Development Options	**Differences From the Chosen Development Option**
Land-based option	• Gas processing on land-based facilities on the east bank of the Kumak Channel, including a barge landing and access road to these facilities
Island dehydration	• Gas processing on land-based facilities on the east bank of the Kumak Channel • An additional dehydration facility on Niglintgak Island to remove water before the river crossing
Taglu processing	• No processing facilities at Niglintgak; all raw gas transported to Taglu for dehydration and compression
Two river crossings	• A land-based processing facility located on Niglintgak Island, with river crossings for both the raw gas and gathering pipeline
Minimum drilling footprint	• Five wells drilled from one Niglintgak Island-based drilling pad to reduce the land footprint • A land-based processing facility located on Niglintgak Island
Niglintgak Island	• Six wells drilled from three well pads, with all three well pads located on Niglintgak Island • A land-based processing facility located on Niglintgak Island
Outside Kendall Island Bird Sanctuary	• Six wells drilled from three well pads • Well pads and a land-based processing facility located outside the bird sanctuary on the west side of the Middle Channel
Artificial island	• An artificial island constructed near the south end of Niglintgak Island to support the well pads and processing facility
East bank	• Two wells drilled from one well pad on the east bank of the Kumak Island to access the southern part of the reservoir only

Table 4-4 summarizes the key weaknesses of the eliminated options.

4.3.3 DETAILED EVALUATION

Evaluation of the two remaining development alternatives, the barge option and land option, was continued with technical, socio-economic and environmental assessments being completed for both options. The EIS provides details on the assessment of both the proposed development and the land-based processing option.

Table 4-4: Niglintgak Development Options Evaluation

Development Option	Key Factors in Elimination
Island dehydration	Minimal technical, economic or environmental benefits, with significant additional capital expenditure.
Taglu processing	Capital savings and reduced footprint insufficient for the increased technical concerns with: • operation of the longer wet flow line • reduced resource recovery with remote compression • loss of Niglintgak area facility benefits to future area development
Two river crossings	Benefits of relocating the gas processing facility to Niglintgak Island are insufficient for the additional capital expenditures required.
Minimum drilling footprint	Benefits of a reduced footprint are insufficient for the significant reduction in resource recovery because of the technical limits of drilling high-lateral-reach to true-vertical-depth ratio wells (long-reach drilling) required to access all reservoir compartments.
Niglintgak Island	Benefits of a less complex gathering system are insufficient compared to the loss of resources and increased complexity associated with the long-reach drilling required.
Outside Kendall Island Bird Sanctuary	Benefits associated with being outside the bird sanctuary are insufficient to offset the reduced resource recovery because of long-reach drilling, increased capital expenditures and additional environmental concerns.
Artificial island	The reduction in the land footprint is insufficient to offset loss of resources because of long-reach drilling and environmental concerns.
East bank	The reduction in the land footprint and the savings in capital expenditures are insufficient to offset loss of resources because of decreased well penetrations of resource-bearing sands.

The major differences for the land-based option are:

- the gas conditioning facility would be located on the east bank of Kumak Channel on a combined piled and gravel foundation
- a new dredged barge landing site would be required on the east bank of Kumak Channel, with an access road from the landing site to the gas conditioning facility

4.3.3.1 Evaluation Results

Based on the evaluation work completed, the barge-based processing facility option was chosen over the land-based option, mainly because:

- the estimated capital cost of constructing the barge-based option is lower than for constructing the land-based option
- constructing the barge facilities off site in a more controlled environment reduces the risk of cost escalation and schedule delays

4.3.3.1 Evaluation Results (cont'd)

- transporting the gas conditioning facility through the Beaufort Sea will reduce the overall Mackenzie Gas Project transportation and logistics requirements on the Mackenzie River. Limitations and bottlenecks associated with river transport logistics have been identified as a concern for the project.
- commissioning and start-up efficiencies will be realized by constructing and pre-commissioning the gas conditioning facility in a controlled environment
- the footprint within the Kendall Island Bird Sanctuary is reduced
- the barge can be refloated, removed and salvaged at the end of its life

4.3.3.2 Concerns and Future Work

Two concerns identified for the current development plan compared to a land-based processing alternative were:

- the potential need for dredging in the Beaufort Sea and the Mackenzie River
- the potential that constructing the barge facilities off site might reduce local employment opportunities in the short term

The impact of dredging in the Beaufort Sea and Mackenzie Delta was assessed in the EIS. No significant environmental impacts resulting from the expected dredging requirements were identified. Field programs to collect additional data will be completed in summer 2004 and will enable the dredging requirements to be further refined and optimized.

The barge option will result in some construction employment opportunities leaving the region and, possibly, Canada. However, the socio-economic assessment completed for the Mackenzie Gas Project indicates that this impact will be minimal because the project will generate more construction jobs than can be filled by the northern workforce. Ongoing long-term operations jobs and business opportunities are similar for both options.

4.4.1 FUTURE POTENTIAL DEVELOPMENT

The Niglintgak field consists of multiple stacked sands, primarily filled with dry gas. However, the field also contains some sands filled with oil and associated gas.

Low to medium (18 to 32) American Petroleum Institute (API) gravity oil is contained in the following reservoir sands:

- I, J and K
- L-low
- M-low
- O-P
- Q and R

The L-low, M-low and O-P sands have associated gas caps.

These resources are not likely to be developed in the foreseeable future.

4.4.2 OTHER SIGNIFICANT DISCOVERY LICENCES

Shell has working interests in several SDLs that hold smaller volumes of natural gas. Although no specific plans have been formulated yet, these volumes might be tied into the Niglintgak development during the life of the project.

4.4.3 FUTURE RESOURCE EVALUATIONS

Some evaluation tests might be done in the north end of the field to clarify the uncertain nature of hydrocarbon fill in the H0 sand. The thin sands at the top of the O-P unit might contain non-associated gas. In addition, some potential remains for resource recovery from the Richards Sequence above the A sand. Before drilling begins, a decision will be made about evaluating these intervals and potentially incorporating them into the plan during the production phase.

4.4.4 SPECIAL DRILLING SPACING UNITS FOR SUBSURFACE DRILLING LOCATIONS

The wells in the Niglintgak field will be drilled to reach the optimal subsurface targets of the reservoirs. The current subsurface targets are located mainly at high elevation points on the crest of the structure that will allow for maximum gas recovery mainly through delay in future water production. The final detailed well trajectories will be derived from ongoing seismic and geological analyses.

To locate the wells on the crest of the structure, the wells probably will not be drilled according to the gas spacing unit format of the Draft Spacing Unit Regulations. Therefore, this will necessitate a special drilling spacing unit application, as described in the draft regulations, before drilling begins.

Shell owns 100% of the subsurface rights of SDL 19. The planned bottomhole locations of the wells will be located on SDL 19, and will not encroach upon the one grid unit buffer zone between adjacent landowners that is contemplated in the draft regulations. Therefore, these locations will not affect other leaseholders' subsurface rights.

More than one well per section per reservoir unit might be needed to provide efficient drainage of the gas in the case where more compartmentalization of the reservoirs than is currently interpreted becomes apparent. The proposed buffer zone is shown in Figure 4-4.

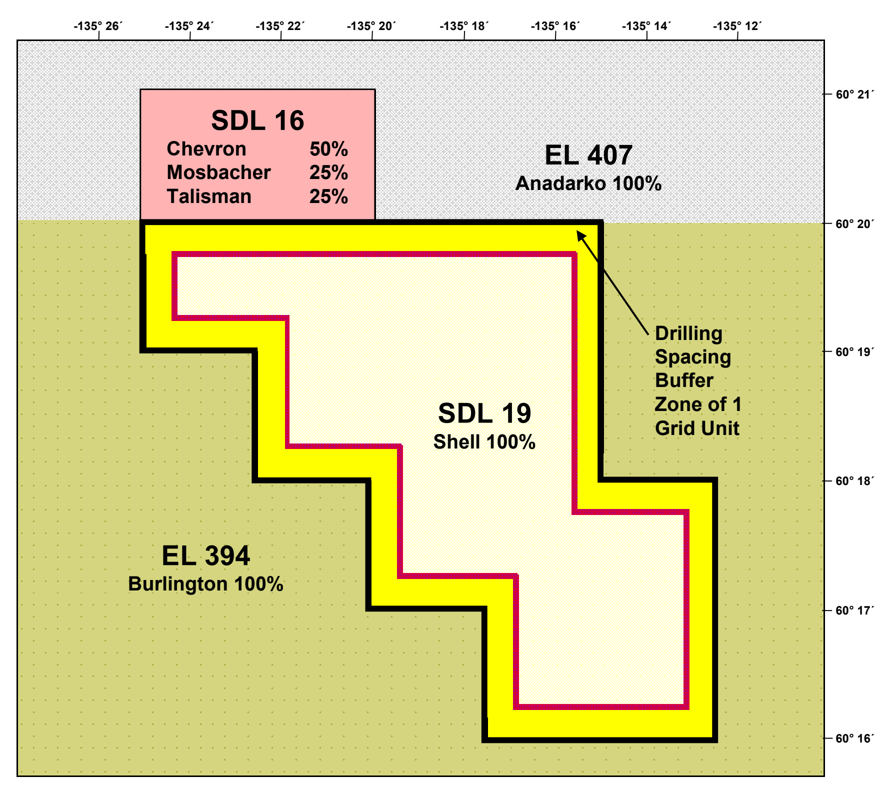

Figure 4-4: Special Drilling Spacing

4.5.1 PURPOSE OF DATA COLLECTION

The reservoir management plan for Niglintgak includes systematically collecting well and reservoir data throughout the field's life cycle. Data collection starts when the wells are drilled. Data is collected through logs, cores, multi-formation tests and production tests to establish reservoir parameters and initial reservoir conditions. Pressure, production rate and fluid type data is collected and analyzed from the wells as the field matures, with the goal of early recognition and mitigation of any problems that might affect resource recovery.

4.5.2 MONITORING PROGRAM

Reservoir monitoring is necessary to ensure that the Niglintgak development operates effectively to optimize gas recovery and production. Well and reservoir monitoring requires:

- a method of systematically gathering, evaluating and documenting reservoir performance
- a thorough knowledge of how the wells and reservoir are functioning, so that any production anomalies can be identified and corrected

4.5.2.1 Formation Evaluation

A formation evaluation plan, including wellbore logging and coring, will be conducted when the wells are drilled. This data will be used with other data collected as the field is produced, to analyze reservoir performance.

4.5.2.2 Monitoring Objectives

The main objectives of well and reservoir monitoring are to:

- optimize field development and gas recovery
- help evaluate GIIP and resources
- help predict, plan and optimize production
- characterize the reservoir's properties

4.5.2.2 Monitoring Objectives (cont'd)

- identify production and technical problems as early as possible, so that corrective and mitigative actions can be taken before significant production loss occurs
- provide a historical and current database for:
  - pressure
  - production
  - gas
  - fluid samples
- provide well and reservoir information to help evaluate well and reservoir performance effectively

4.5.2.3 Monitoring Strategy

The monitoring strategy will be to obtain production and pressure data from different surface and subsurface locations. Reservoir monitoring data will be used to:

- update the resource estimates
- monitor:
  - well performance
  - reservoir performance
  - aquifer influx and support
  - water production
  - sand control
- obtain a history match to update the current reservoir 3-D model
- manage ongoing well intervention workovers and infill drilling programs

4.5.2.4 Monitoring Criteria

Flexibility is a key component of the monitoring plan. The major criteria affecting monitoring requirements are the:

- maturity of the project or reservoir
- complexity of the well or reservoir

Maturity of the Project or Reservoir

As the reservoir matures or progresses through different phases, the monitoring effort required will change, as follows:

- initial or early life – This period covers the first two years of production. It is essential that a good database be obtained during this period for:
  - future evaluations
  - early recognition and mitigation of problems

- mid-life – This period extends from early life performance to or beyond the point of water breakthrough. It might encompass one or more major integrated reviews or studies. During this period, major changes might be required to ensure that optimum recovery is achieved. Infill drilling might be considered to ensure that drainage is adequate for optimum recovery.
- late life – This period covers the latter stages of reservoir depletion (the last 10% of the ultimate recovery). During this period, key monitoring of small-scale changes will help ensure that all zones and areas are adequately drained. For example, the monitoring might result in:
  - isolating a high-water-producing zone
  - recommending additional recompletion in an area of poor sweep efficiency

Complexity of the Well or Reservoir

The amount of monitoring required is also a function of the well's or reservoir's complexity. For example, a multizone, heterogeneous reservoir or commingled well might require more or different types of monitoring than a homogeneous reservoir with a single zone completion. The level of monitoring will be determined as information about the reservoir becomes available.

4.5.3 IMPLEMENTATION PROCESS

Implementing the proposed reservoir management plan involves four steps:

1. Obtain data.
2. Analyze data.
3. Document results.
4. Address main uncertainties early.

4.5.3.1 Obtaining Data

The initial implementation effort will require the coordinated efforts of the subsurface team members (reservoir, petrophysics, geology and geophysics), production engineering and operations. Data collection activities need to take into account the full life cycle of the project or field.

Daily monitoring data will include:

- surface tubing head pressures
- surface tubing head temperatures
- gas and water production

Data will also be acquired from:

- bottomhole pressure surveys
- well production testing
- production logging

4.5.3.2 Analyzing Data

Data collected will be used to:

- evaluate the performance of reservoir properties
- identify production contributions from individual sands
- address specific uncertainties in field or reservoir development scenarios

To evaluate fault transmissibility across field blocks, interference tests across the faults will be done, if conditions are suitable.

Key modern data monitoring techniques, such as downhole permanent pressure gauges, will be assessed to determine their merit and level of incorporation into the plan.

Reservoir models will be updated periodically to incorporate the new monitoring data.

4.5.3.3 Documenting Results

Niglintgak field review meetings will be held at timely intervals to update and discuss all monitoring data items, including:

- how individual wells are performing
- how monitoring data has been used in performance analysis
- whether any problems associated with monitoring have occurred

Documentation will be prepared showing Niglintgak’s development performance, including an assessment of the ongoing monitoring efforts.

4.5.3.4 Addressing Main Uncertainties Early

The main uncertainties that need to be addressed early in the project include:

- fault configurations, their locations and sealing nature
- aquifer support and its impact on water breakthrough in wells
- the reservoir’s nature and performance

4.5.4 FOUR-DIMENSIONAL SEISMIC

Four-dimensional (4-D) seismic is an evolving reservoir monitoring technology that compares pre-production seismic data with new seismic data acquired during field production. Subsurface reservoir fluid movements can be monitored by comparing the difference between the two data sets. Shell will continue to monitor and evaluate this technology and review its applicability to the Niglintgak field.

4.6.1 KEY FEATURES

Key features of the chosen development plan include:

- wells
- well completions
- reservoir evaluation programs
- production forecasts and assumptions
- well pad facilities and flow line
- a gas conditioning facility
- utilities and support systems

4.6.2 WELLS

The well drilling program is planned for three winter seasons, using two rigs, and includes:

- six to 12 production wells
- one disposal well
- three well pads:
    - north pad (H-30) – wells P-3, P-4, P-4L, and P-11 will be located at this pad
    - central pad (B-19) – well D-1 will be located at this pad
    - south pad (E-58) – well P-2 and the disposal well will be located at this pad

4.6.3 WELL COMPLETIONS

Completions are designed with:

- an evaluation program in key zones
- zonal water shutoff capabilities
- downhole sand control
- hydrate inhibition

4.6.4 RESERVOIR EVALUATION PROGRAMS

The reservoir will be evaluated and monitored by:

- an initial formation evaluation logging and coring program in key sands
- a well and reservoir monitoring plan

4.6.5 PRODUCTION FORECAST AND ASSUMPTIONS

The following production forecast is expected from the field:

- a nominal field raw gas production rate of 4.3 Mm^3/d (150 MMscf/d), allocated as:
    - 3.5 Mm^3/d (121 MMscf/d) from the A sand reservoir (four wells)
    - 0.6 Mm^3/d (22 MMscf/d) from the D, E, and F-G sand reservoirs (one well with commingled production)
    - 0.2 Mm^3/d (7 MMscf/d) from the L, M and N sand reservoirs (one well with commingled production)
    - a cumulative total gas recovery of 26.9 Gm^3 (950 Bcf)

The forecast is based on the following assumptions:

- production forecasts, including positive skins of 5 to 10
- a tubing head abandonment pressure of 1,724 kPa
- compression from start-up
- an economic production life of about 25 years
- a plateau rate for 13 to 14 years
- 100% availability

4.6.6 WELL PAD FACILITIES AND FLOW LINES

The field production facilities comprise:

- three well pad facilities constructed on elevated pile foundations
- three above-ground flow lines to connect the well pads to the gas conditioning facility
- an HDD crossing under the Kumak Channel
- power cable, fuel gas and chemical lines, installed with the flow lines connecting the well pads and the gas conditioning facility

4.6.7 GAS CONDITIONING FACILITY

The gas conditioning facility will be constructed offsite and towed to site through the Beaufort Sea. The facility will be located on a permanent foundation in the Kumak Channel, and will have:

- three-phase inlet separation
- mole sieve dehydration
- propane refrigeration
- water and sand handling facilities
- two-staged compression built from start-up

4.6.8 UTILITIES AND SUPPORT SYSTEMS

The systems supporting the ongoing operation and maintenance of the facilities are:

- a helicopter landing pad
- on-site accommodations
- control rooms at the gas conditioning facility and Inuvik
- control and communications systems
- power generation, building heat, heat tracing and tankage
- flares and safety systems
- tankage and storage