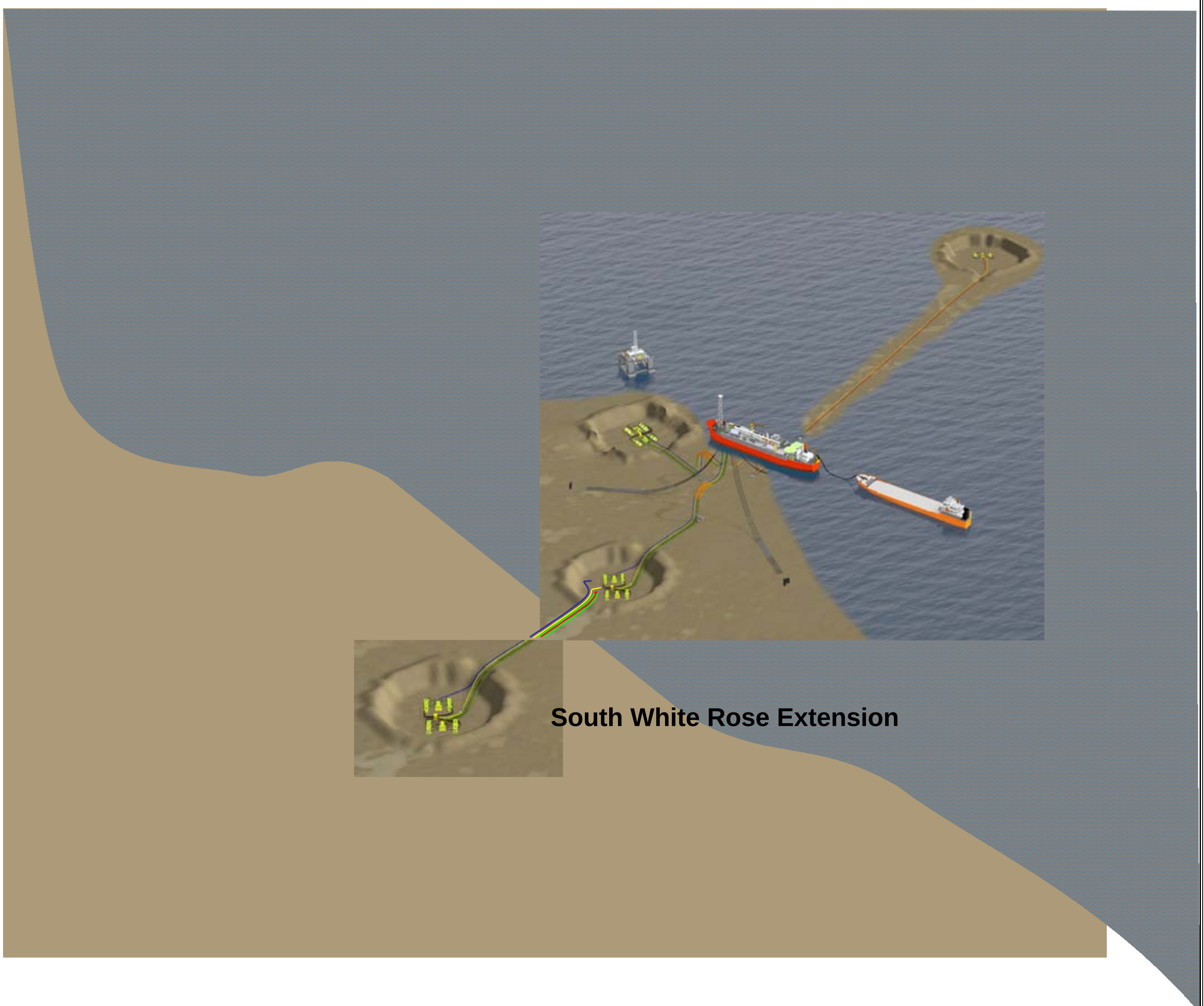
White Rose Development Plan Amendment -

South White Rose Extension Tie-back



September 2006

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Executive Summary

Husky Oil Operations Limited (Husky) and its partner Petro Canada propose to undertake an expansion of its White Rose Development in the Jeanne d'Arc Basin on the Grand Banks within the Significant Discovery License areas 1043 and 1044. Specifically, the expansion will consist of a subsea tie-back to the FPSO through the existing Southern Glory Hole (SGH) and utilizing a new glory hole constructed approximately 4 km south of the SGH.

The South White Rose Extension Tie-back (SWRX) is being considered for development. The total predicted recoverable oil from the SWRX is between 20 and 25 mm bbls on a P50 basis. The estimated cost of the SWRX is in the range of $600 million (CDN). The SWRX Tie-back is considered to have borderline economics. The tie-back adds only a 10% increment to the stated White Rose oil reserves but will cost 25% of the original White Rose development budget. The escalation in cost is due to strong global demand for services, resources and materials.

The SWRX development will produce from a thin oil column in the Ben Nevis Formation. The oil column is overlain by a large gas cap and connected to a regional aquifer in some fault blocks. Secondary recovery is planned through water injection and regional aquifer support. SWRX is an extension of White Rose in terms of depositional setting and filling history, however the pool contains different hydrocarbon contacts than the main White Rose development.

The new glory hole for SWRX will be strategically positioned to also provide future access to the Southwest White Rose Extension reservoir area. A delineation drilling program is currently underway to determine the existence of reserves in this area that may be within reach of the SWRX drilling center. At this time, it is anticipated that the SWRX drill centre will initially comprise three production wells and two water injection wells with expansion capacity to eight wells. The glory hole will be large enough to expand the drill centre up to 16 wells.

The glory hole construction and subsea installation activities associated with developing the tie-back will be similar to those employed for the existing White Rose Development. The SWRX tie-back will require minor modifications to the topsides processing plant, mainly in the area of chemical injection and storage. The existing White Rose control system was designed with adequate spare capacity to allow reconfiguration of the base capacity and the addition of SWRX.

A review of the White Rose Benefits Plan and its application to the SWRX Tie-back has been submitted to the C-NLOPB as a separate report.

As further information becomes available, plans will be modified and refined. Submission of this document does not commit Husky to proceed with the tie-back. It should also be noted that this potential tie-back is currently in the preliminary front end engineering (FEED) phase and has not yet been sanctioned by the White Rose partners.

1.0 Introduction

Husky Oil Operations Limited (Husky), as the Operator and in joint-venture with Petro-Canada, submitted a Development Application (DA) for the White Rose Development to the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) in January 2001. This DA was prepared pursuant to the Canada-Newfoundland Atlantic Accord Implementation Act and the Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act. The C-NLOPB approved the White Rose DA in December 2001. The Production License PL 1006 applies to the existing White Rose Development.

This document is being submitted to outline a proposed amendment to the original Development Plan. Namely, Husky and its partner Petro Canada propose to undertake an expansion of its White Rose Development in the Jeanne d'Arc Basin on the Grand Banks within the Significant Discovery License areas 1043 and 1044. Specifically, the expansion will consist of a subsea tie-back to the FPSO through the existing Southern Glory Hole (SGH) and utilizing a new glory hole constructed approximately 4 km south of the SGH.

2.0 Development Overview

2.1 Preamble

The White Rose oil field is located on the Grand Banks, approximately 350 km east of the Island of Newfoundland on the eastern edge of the Jeanne d'Arc Basin (Figure 2.1)

Figure 2.1 - White Rose Oil Field

The White Rose Significant Discovery Area consists of both oil and gas fields or pools, including the South Avalon Pool, the North Avalon Pool, and the West Avalon Pool. The main oil reservoir at White Rose is the Ben Nevis - Avalon Formation sandstone.

The White Rose Development utilizes a Floating, Production, Storage and Offloading (FPSO) facility, with ice avoidance capacity (quick disconnectable turret), and subsea wells. Crude oil is transported to market by shuttle tankers. Oil production from the White Rose field commenced in November 2005.

Subsea installations for the initial development scope (South Avalon) consisted of a potential of 21 subsea wells. To date, 18 wells have been planned with 13 drilled and completed (7 water injection, 1 gas injection, 5 oil producers). The wells are manifolded and connected to flowlines and flexible risers which terminate at the FPSO. To accommodate small scale growth in the overall White Rose Development, limited design flexibility was included to allow for the addition of some production and injection wells within existing glory holes. These wells could then be used to develop nearby ancillary oil pools in the future should they be proven commercially viable.

The White Rose Development Plan identified North Avalon and West Avalon Pools as potential areas for future development to enable maintenance of the oil production plateau after 2008. Development of these pools would allow the FPSO to continue to be used at capacity levels for a longer period of time thus helping to extend the economic life of the South Avalon Pool.

To this end, the South White Rose Extension (SWRX) area is being considered for development (Figure 2.2). This area is located approximately 4 km south of the current SGH, in approximately 120 m of water. At present, consideration is being given to developing this southern region by excavating a new glory hole. The new glory hole will be strategically positioned to also provide future access to the Southwest White Rose Extension reservoir area. A delineation drilling program is currently underway to determine the additional production that may be within reach of the SWRX drilling center. Within the glory hole, one new drill centre is being considered with wells tied back to the FPSO via the current SGH. At this time, it is anticipated that the SWRX drill centre will initially comprise three production wells and two water injection wells with expansion capacity to eight wells. The glory hole will be large enough to expand the drill centre up to 16 wells should it be required in the future.

The total predicted recoverable oil from the SWRX is between 20 and 25 mm bbls on a P50 basis. The estimated cost of the SWRX is in the range of $600 million (CDN). The SWRX Tie-back is considered to have borderline economics. The tie-back adds only a 10% increment to the stated White Rose oil reserves but will cost 25% of the original White Rose development budget. The escalation in cost is due to strong global demand for services, resources and materials. Identified risks associated with development of the SWRX include:

- Uncertainty around subsurface mapping and reserve ranges;
- Substrate issues related to glory hole excavation;
- Ability to secure long lead materials;
- Capital cost escalation due to tight market conditions; and
- Drilling rig availability and day rate sensitivity.

As further information becomes available, plans will be modified and refined. Submission of this document does not commit Husky to proceed with the tie-back. It should also be noted that this potential tie-back is currently in the preliminary front end engineering (FEED) phase and has not yet been sanctioned by the White Rose partners.

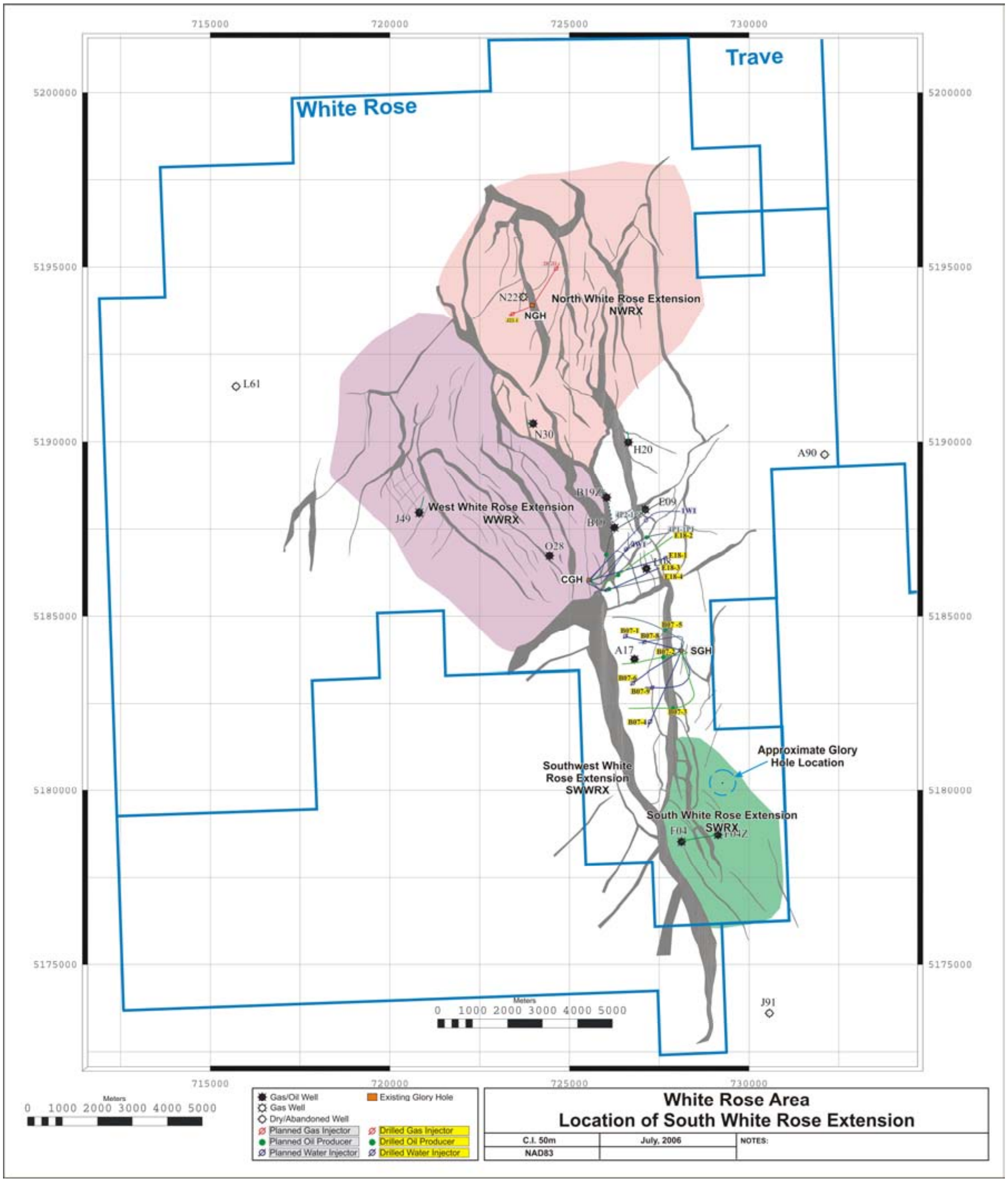


Figure 2.2 - Location of South White Rose Extension

2.2 Development of the SWRX

2.2.1 Glory Hole Construction

Glory hole construction methods will mainly be the same as those employed for development of the South Avalon Pool; that is, the glory hole will be dredged using a trailing suction hopper dredging vessel. This type of dredger is a self-propelled ship which fills its hold or hopper during dredging while following a pre-set track. Dredged material will be disposed of in the approved spoils disposal area used during construction of the glory holes for White Rose. However, the glory hole for SWRX will be larger and deeper than those constructed for the South Avalon Pool. The glory hole needed to support establishment of the drill centre will be excavated to a maximum of -9 to -11 metres below existing seabed level with a maximum “floor” dimension of 70 m by 70 m with graded sloped sides as required for stability and flowline ramps. The increased dimensions result from enhancements to the original White Rose Development glory hole design. Specifically:

- The depth will allow equipment to be installed with a clearance from the seabed floor to decrease exposure of wellheads and associated equipment to irregularities in excavation and sedimentation in the bottom of the glory hole;
- A larger size will facilitate improved movement of ROVs, easier equipment installation, and to allow for possible installation of a universal subsea tree structure currently being assessed; and
- Graded slope ramps will facilitate placement of flow lines and may enhance removal or movement of sediment out of the glory hole through increased current flow.

The proposed glory hole layout for SWRX is indicated in Figure 2.3.

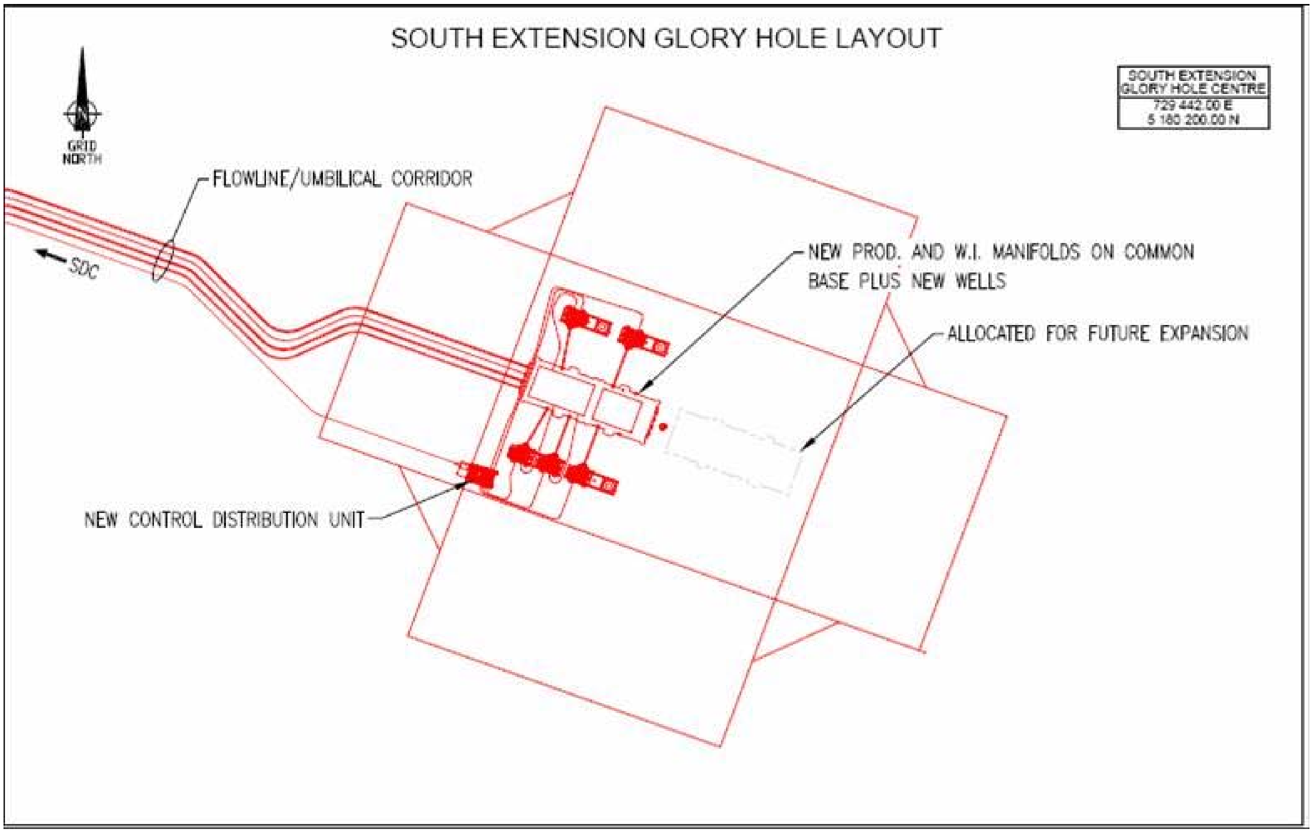


Figure 2.3 - Proposed SWRX Glory Hole Layout

2.2.2 Subsea Equipment Installation

The new drill center will be tied back into the existing Southern Drill Centre (SDC) using subsea flowlines (Figure 2.4). The subsea system will be connected via, and in tandem with, the current subsea production system feeding the SDC (i.e., piggy backing through the same flowlines, chemical lines and control umbilical feeding back to the Sea Rose FPSO). Subsea tie-in work in the SGH and subsea installation, connections and tie-in work in the SWRX glory hole will require use of divers and remotely operated vehicle (ROV) technology.

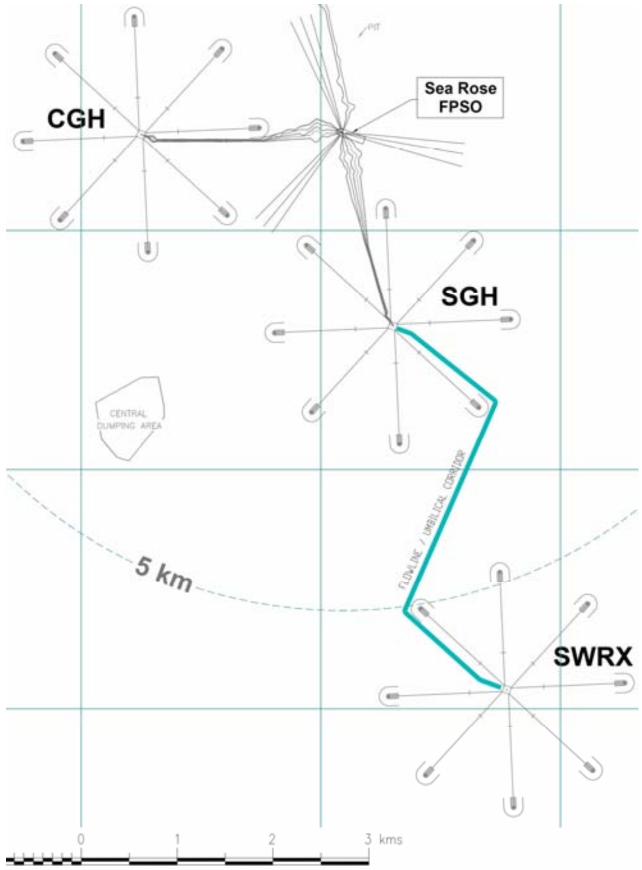


Figure 2.4 - SWRX Tieback to the SGH

The subsea facilities at SWRX will include all equipment necessary for the safe and efficient operation and control of the subsea wells and transportation of production and injection fluids between the wells and the SDC. No changes to existing flowlines, risers or umbilical are anticipated. The umbilical and flowlines utilized for SWRX will be of similar design and specifications as those installed during initial development. It is expected that two 10-inch oil production flowlines, one 8-inch water injection flow line and an electro-hydraulic multiplex (EHMUX) umbilical will be routed approximately 5 km from the SWRX to the SDC. Similar to the White Rose Development, flowlines for SWRX will be laid on the seafloor and will be insulated for temperature and flow assurance purposes. The SWRX reservoir temperature is estimated to be similar to that of the White Rose reservoir (see Section 4.1.1). As a result, there is no anticipated requirement for changes to the design of the flexible flowlines.

The SWRX Tie-back will require modifications of the SDC to extend flowlines and controls (Figure 2.5). Procedures for installation of subsea facilities and subsequent operations for SWRX are anticipated to be similar to those currently employed for the initial phase of White Rose Development. Once installation is completed, the system will be fully tested prior to being brought back into service through the existing infrastructure to the SeaRose FPSO.

The subsea facilities will be configured to allow production well testing to be performed by routing individual wells through a test flowline to the test separator on the FPSO or via an equivalent agreed upon system. Whenever well testing is not ongoing, the test line will continue to be used for production to mitigate wax formation in the line. Round trip pigging of the production and test lines will be extended from the SDC to the SWRX drill centre.

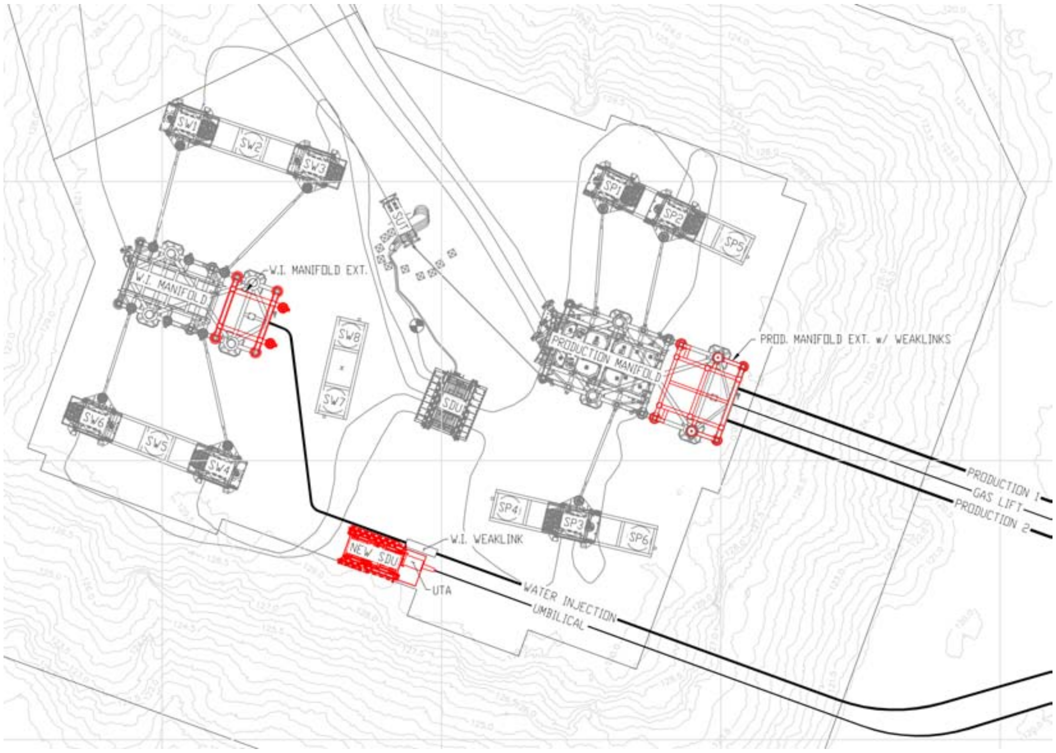


Figure 2.5 - SDC Modifications to Support the SWRX Tie-back

Extension modules required to tie-in equipment will be installed on the manifolds structural foundations in the SDC. Flowlines from SWRX will enter the SDC manifolds after passing through these extension modules (refer to Figure 2.5). The design of the manifold that will be employed in the SWRX drill centre will be modified from the original to provide more flexibility regarding number of oil producers versus water injectors.

Iceberg protection measures applied to the current White Rose Development will also be applied to the SWRX including placement of wellheads, Xmas trees and manifolds in glory holes, with the top of the equipment having a minimum clearance of 2 to 3 m below the seabed level and use of flowline and umbilical weak link technology.

2.2.3 Drilling and Completions

Drilling and Completions activities will be carried out using existing White Rose processes and systems. The SWRX Tie-back will utilize well templates and wellhead systems similar to those used on the White Rose Development.

In general the SWRX tie-back well design and drilling operations programs will be based on experience from the White Rose Development. Synthetic-based muds will be used to drill the intermediate and production hole sections. Best available technology will continue to be utilized to minimize synthetic drill mud on cuttings. Advanced directional drilling tools and systems will continue to be used to drill the deviated and horizontal wells required to develop this region of the field.

Existing White Rose cementing practices will be applied to the SWRX Tie-back. White Rose drilling practices employed to drill the conductor and surface hole sections will be applied to SWRX to mitigate the impact of drill cuttings and cement spillage into the glory hole. Specifically, Guar gum sweeps, cuttings transport systems and reduced excess cement will be used in conjunction with a modified template system.

The SWRX Tie-back well completions will be designed to maximize well productivity while maintaining necessary standards of risk and well integrity. “Smart” water injection and production wells may be utilized for SWRX. "Smart" completion technology is required for the water injection wells to control injection profiles into two reservoir intervals. The control of flow would be from a variable interval control valve operated hydraulically. The hydraulically controlled valve is operated from the subsea pod via the subsea umbilical. Final design of the drilling program and the SWRX wells will be addressed in the individual Approval to Drill a Well (ADW) applications. Details of the completion design and installation plan will be outlined in the individual completion programs.

2.2.4 FPSO (Topsides/Turret) Modifications

The SWRX will require some very minor modifications to the topsides processing plant mainly in the area of chemical injection and storage. A review of chemical usage will be carried out to ascertain the necessary storage capacity for the following chemicals:

- corrosion inhibitor;
- methanol; and
- wax inhibitor.

The piping system for the above chemicals will be reviewed to determine if line size increases are required to match the necessary delivery volume required to meet the SWRX needs.

The existing White Rose control system was designed with adequate spare capacity to allow reconfiguration of the base capacity and the addition of the SWRX tieback. A revised software control package will be developed in line with operational requirements and will be integrated into the current operation system onboard the Sea Rose FPSO.

2.3 Schedule

A high level preliminary schedule for development of SWRX is provided in Figure 2.6.

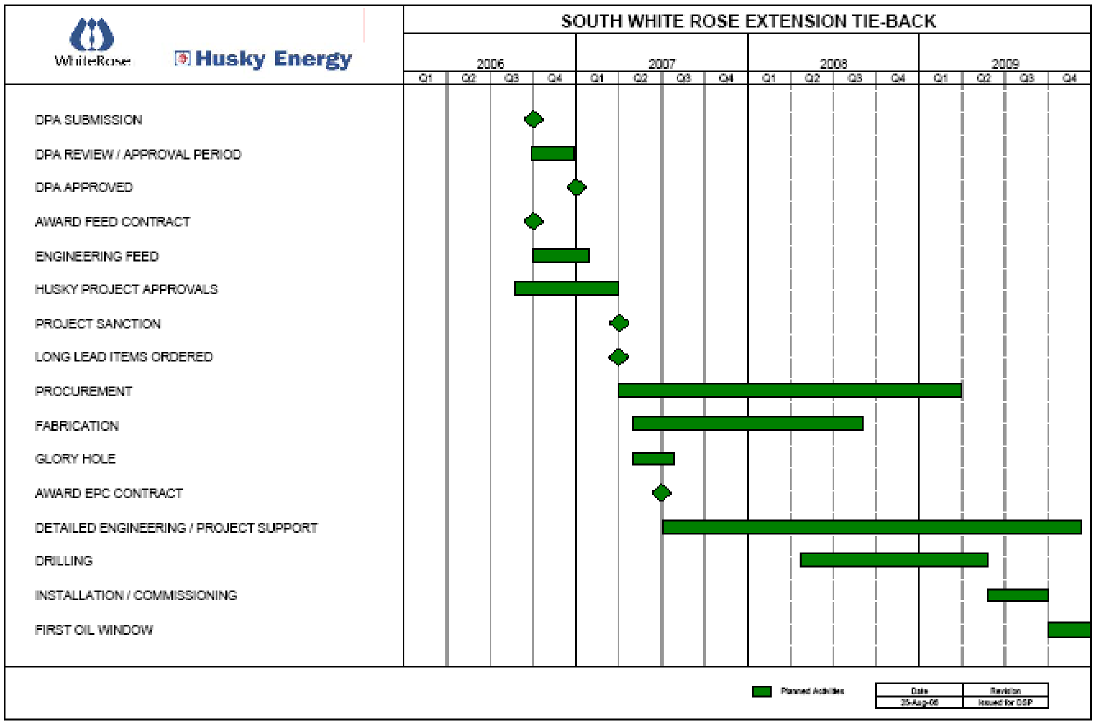


Figure 2.6 - Preliminary Development Schedule for South White Rose Extension

2.4 Management

Husky, as the White Rose Field Operator, will manage the development of the tieback to the FPSO and subsequent operations. The Operator's authority, role, responsibility and reporting requirements are outlined in the White Rose Exploration, Appraisal, Development and Operating Agreement that is already in place.

2.5 Canada-Newfoundland Benefits Commitments

The White Rose Canada-Newfoundland and Labrador Benefits Plan and the regulatory requirements of the C-NLOPB White Rose Development Application Decision Report 2001.01 are applicable to the development of the SWRX Tie-back. A review of the White Rose Benefits Plan and its application to the SWRX Tie-back has been prepared and submitted to the C-NLOPB as a separate report.

3.0 Geology, Geophysics and Petrophysics

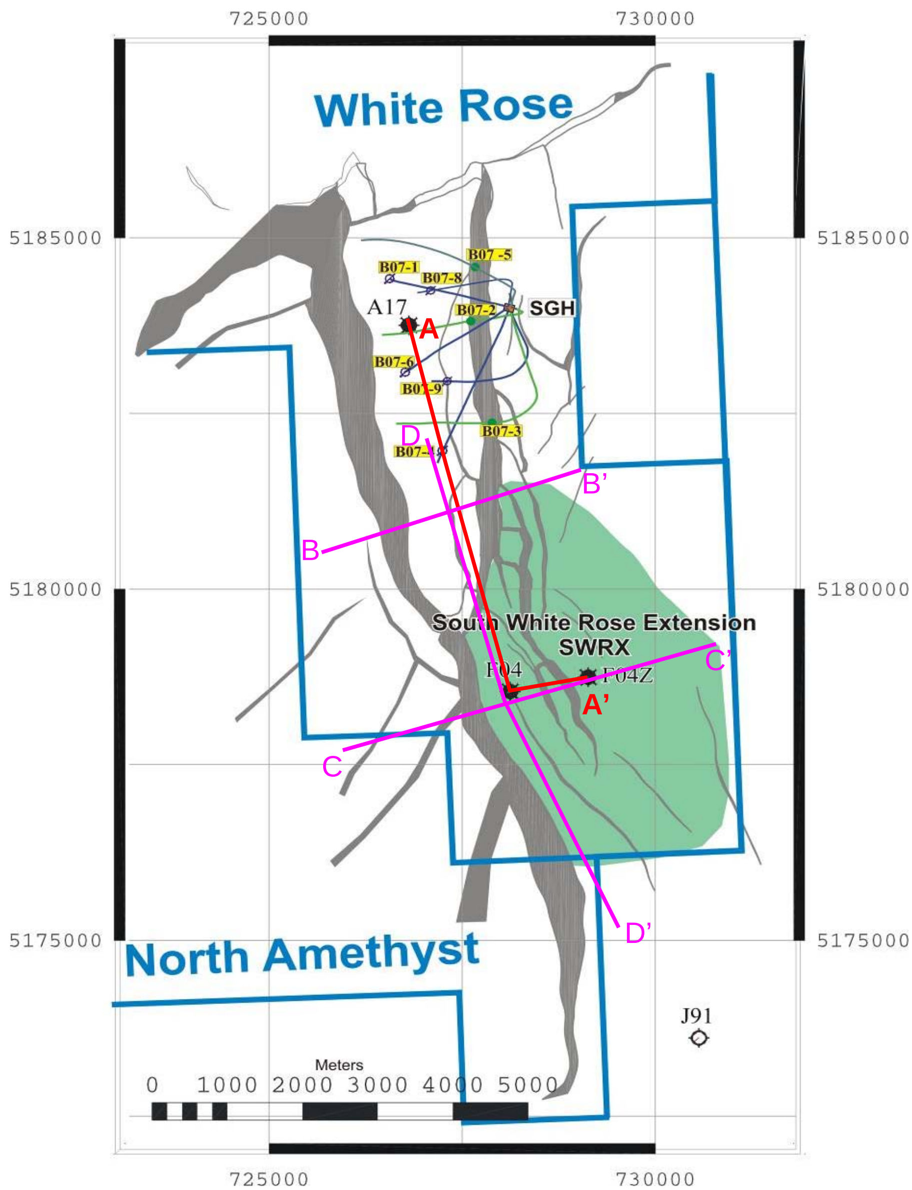
The current geologic interpretation used for geological modeling is an updated version of that presented in the Development Plan for the South Avalon Pool, White Rose Field. At the time of submission there were seven delineation wells in the greater White Rose region that included the South, West, and North White Rose sub-regions. The updated model currently includes all wells within the core White Rose Development region, as well as the F-04 and F-04z wells drilled in the SWRX region in 2003 (Figures 2.2 and 3.1). This brings the total number of wells in the region to 23. The F-04 and F-04z penetrations of the reservoir section in the SWRX region confirmed the presence and quality of the Ben Nevis reservoir to the south of the core development, further delineating the shoreface trend. Development drilling has provided six vertical/deviated (J-22 1, E-18 1, B-07 1, B-07 4, B-07 6, and B-07 8) and seven horizontal (E-18 2, E-18 3, E-18 4, B-07 2, B-07 3, B-07 5, and B-07 9) penetrations of the Ben Nevis reservoir. Although information from these wells has provided a concentrated data set for modeling purposes, no unexpected results were encountered. The same is true for the delineation wells B-19 and B-19z drilled in 2005. As a result, no material changes have been made to the depositional framework (or petrophysical maps) for the Ben Nevis Formation as proposed in 2001. Furthermore, no material changes have been made to the static geological model as provided in the original White Rose Development Plan.

The results of the F-04 and F-04z wells have been tied to the seismic data, and F-04 was used in developing the velocity model for depth conversion. Aside from these minor shifts, the geophysical interpretation has not materially changed since the original Development Application submission.

A note of clarification is required, however, regarding the naming convention used in the White Rose Development Application. The reservoir section was termed the 'Avalon' in the Development Application. It is now believed the reservoir section lies upon the mid-Aptian unconformity, is middle Aptian-Albian in age, and is an overall fining-upward package within a transgressive systems tract, and thus likely to be the Ben Nevis Formation. Reasons for this are twofold. Firstly, biostratigraphic evidence suggests that the reservoir package at White Rose rests unconformably upon Barremian to early Aptian-aged strata. Secondly, seismic defines Jurassic through lower Cretaceous subcrop edges, indicating that the mid-Aptian unconformity at the base of the reservoir is an *angular* unconformity. When this is taken in a regional context, the reservoir section at White Rose correlates favorably to the back-stepping transgressive Ben Nevis Formation. Note that with the two naming conventions spanning the work done in this compilation, Ben Nevis (BN) and Ben Nevis-Avalon (BNA), are used interchangeably throughout this report.

Figure 3.1 - Location Map of the SWRX

(Also indicating the lines of section shown in upcoming figures. A-A' – Stratigraphic/Well sections. All Others – Seismic sections)



3.1 Geology

Current geological understanding places the SWRX in a region of shallow marine lower shoreface deposition trending southwest-northeast. Points A and B on Figure 3.2 illustrate the tectonic relationships to the deposition of the Ben Nevis formation in the White Rose region.

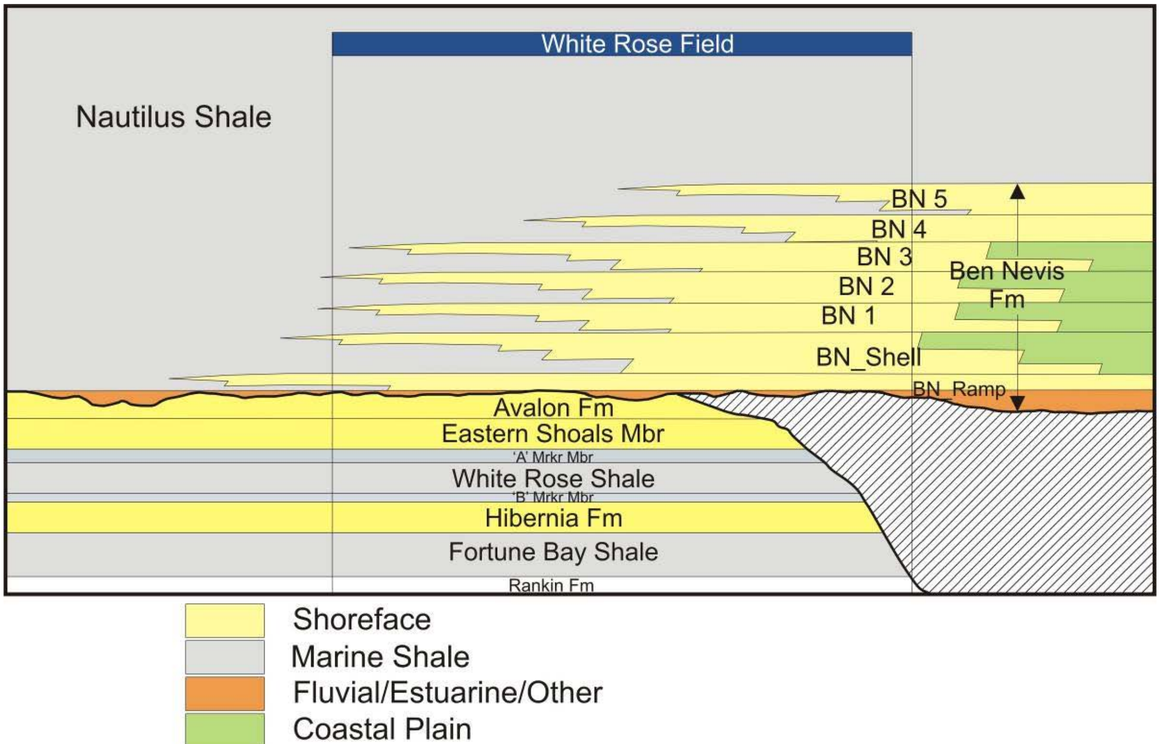
> **A** - Early NTer fault movement results in increased accommodation space and thicker Ben Nevis Fm relative to the southern field extents.
>
> **B** - increased region of accommodation east of the H20 well. No evidence of syntectonic growth is interpreted over the SWRX region. This has been confirmed by the additional 16 well penetrations drilled since the DA submission.

Internal divisions of the Ben Nevis formation represent seven parasequence sets; the BN_ramp, BN_Shell_Cmt, BN_1, BN_2, BN_3, BN_4, and BN_5 from base to top respectively (Figure 3.3). These units correspond with coarsening upwards cycles evident in distal wells (such as H-20), but lose resolution where the net to gross ratio (N:G) is high, and sand-on-sand intra-formational contacts exist. In these regions (SWRX included) the internal divisions are highly interpretational, but correlated through the area nonetheless.

Figure 3.4 illustrates the sequence stratigraphic framework of the Ben Nevis Formation in the extension area. Red correlation lines are representative of the larger cycle parasequence sets used throughout the field and within the reservoir model. The finer spaced grey dashed correlation lines are individual parasequences. These are used for defining fining- or coarsening upward cycles to assist in picking the internal parasequence set boundaries only. They are not defined in the reservoir model and are highly interpretive.

Figure 3.2 - Schematic of Aerial Distribution of Shoreface Sandstone and Early Moving Faults Related to the Initial Phases of Ben Nevis Fm Deposition (Note development wells are not displayed)

Figure 3.3 - White Rose Field Stratigraphy Illustrating the Internal Divisions of the Ben Nevis Formation



The parasequence sets are 4th order cycles that generally are 6 m to 250 m thick, 50 km^2 to 50,000 km^2 in aerial extent, and have a depositional duration of 0.1 Ma to 0.5 Ma. Based on the assumption that these types of scales apply to the Ben Nevis at White Rose, the main correlation surfaces used throughout the field (in red on the cross sections in Figures 3.4 and 3.5) are marking 4th order flooding surfaces bounding the parasequence sets outlined in Figure 3.3. The highly interpretive small scale cycles defined by the grey correlation lines in Figure 3.4 are then representative of 5th order flooding surfaces that frame parasequences. These finer scale surfaces are used only to assist in defining the surfaces associated with the parasequence set division. This maintains consistency in correlation and improves the static modeling framework in the updated reservoir model for the SWRX area.

Structurally the SWRX is segregated into several fault blocks by post-depositional normal faults with throws ranging from <20 m to 300 m. The nearly full offset of the Ben Nevis Formation across the ETer fault (separates terrace from SWRX) allows for different fluid contacts in the extension region relative to those encountered in the A17 terrace region (Figure 3.5).

Figures 3.6 and 3.7 outline the depth structure maps of the top and base reservoir (seismically mapable BNEV_SLTST and mAPT_UC, respectively). Figure 3.8 displays the net sand thickness in the SWRX region, and illustrates the consistent reservoir package that is present throughout the southern White Rose area.

Figure 3.4. Stratigraphic cross-section through SWRX region.

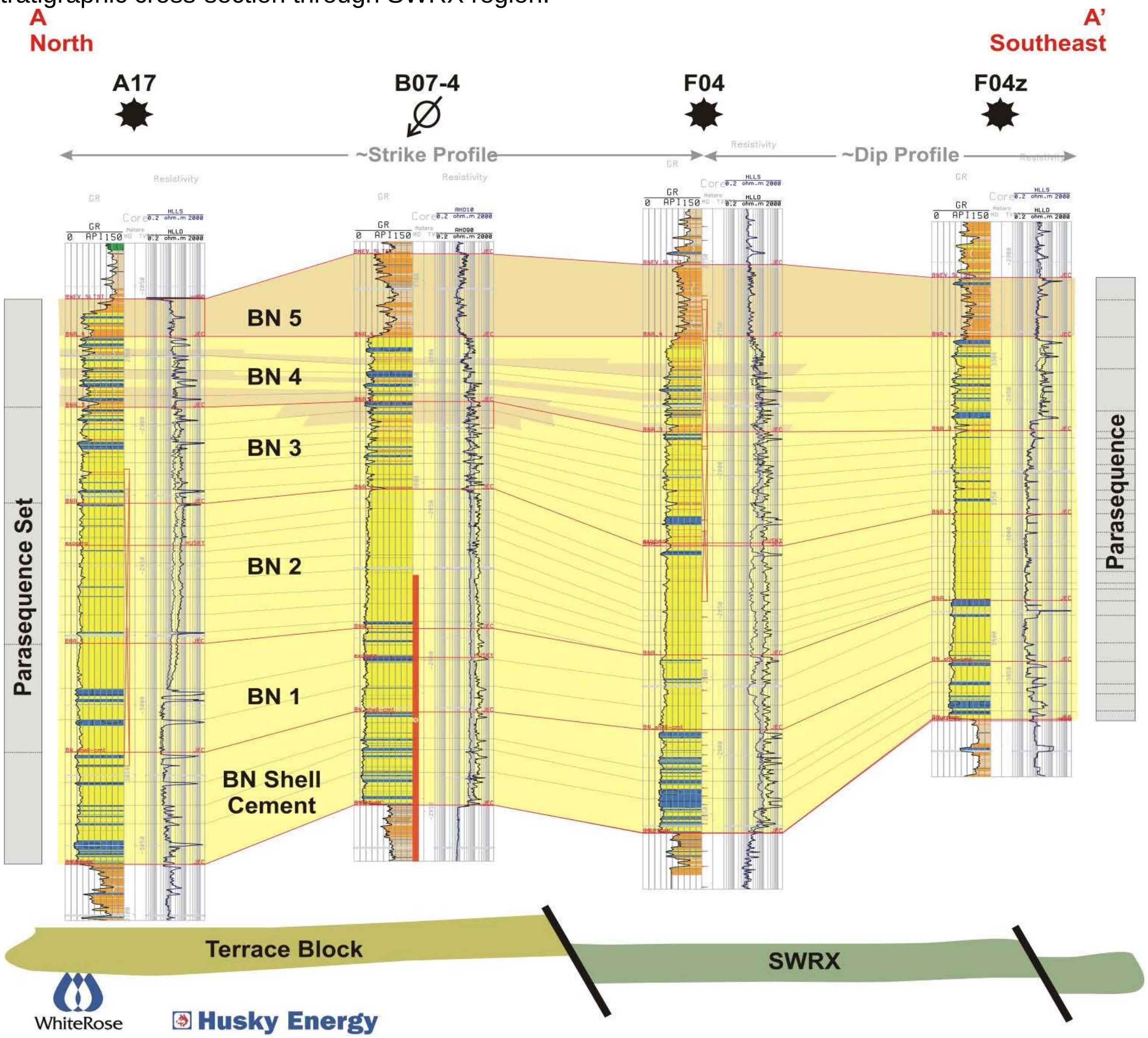


Figure 3.5 - Structural Section Schematic of Terrace to SWRX Region (Note the fluid legs displayed by colour; red – gas, green – oil, blue – water)

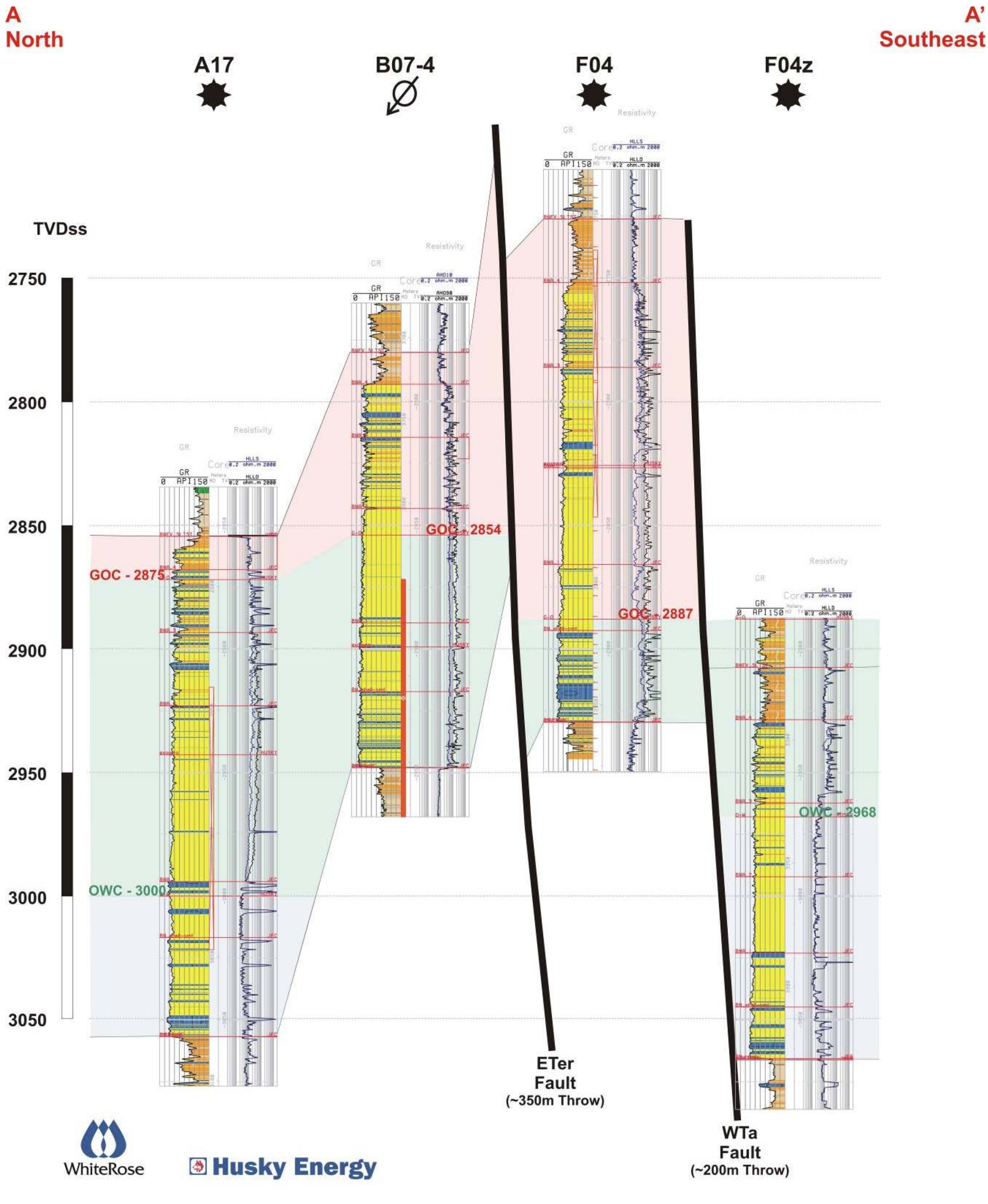


Figure 3.6 - Top Reservoir Depth Structure Map (BNEV_SILTST)

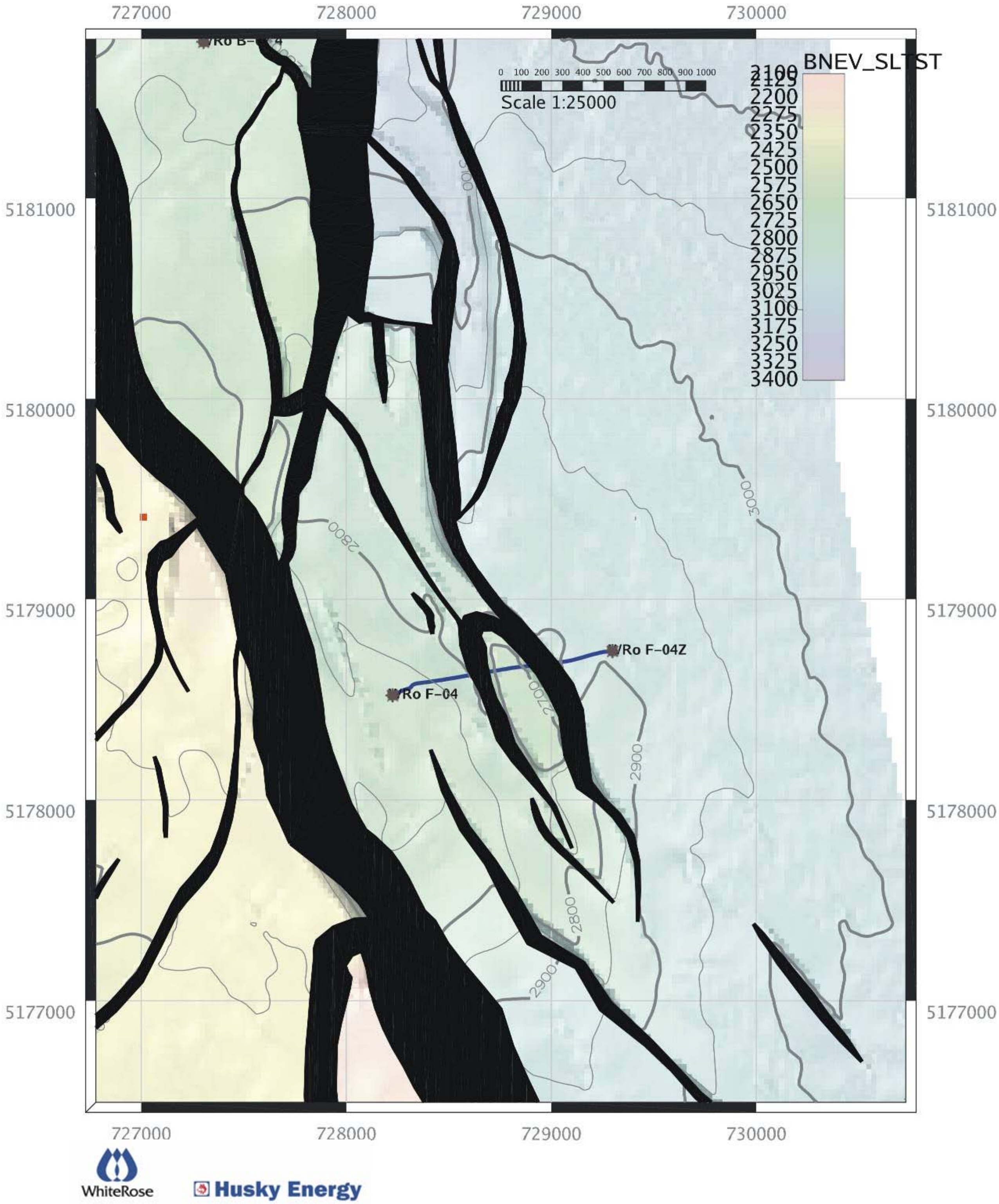


Figure 3.7 - Base Reservoir Depth Structure Map (mAPT_UC)

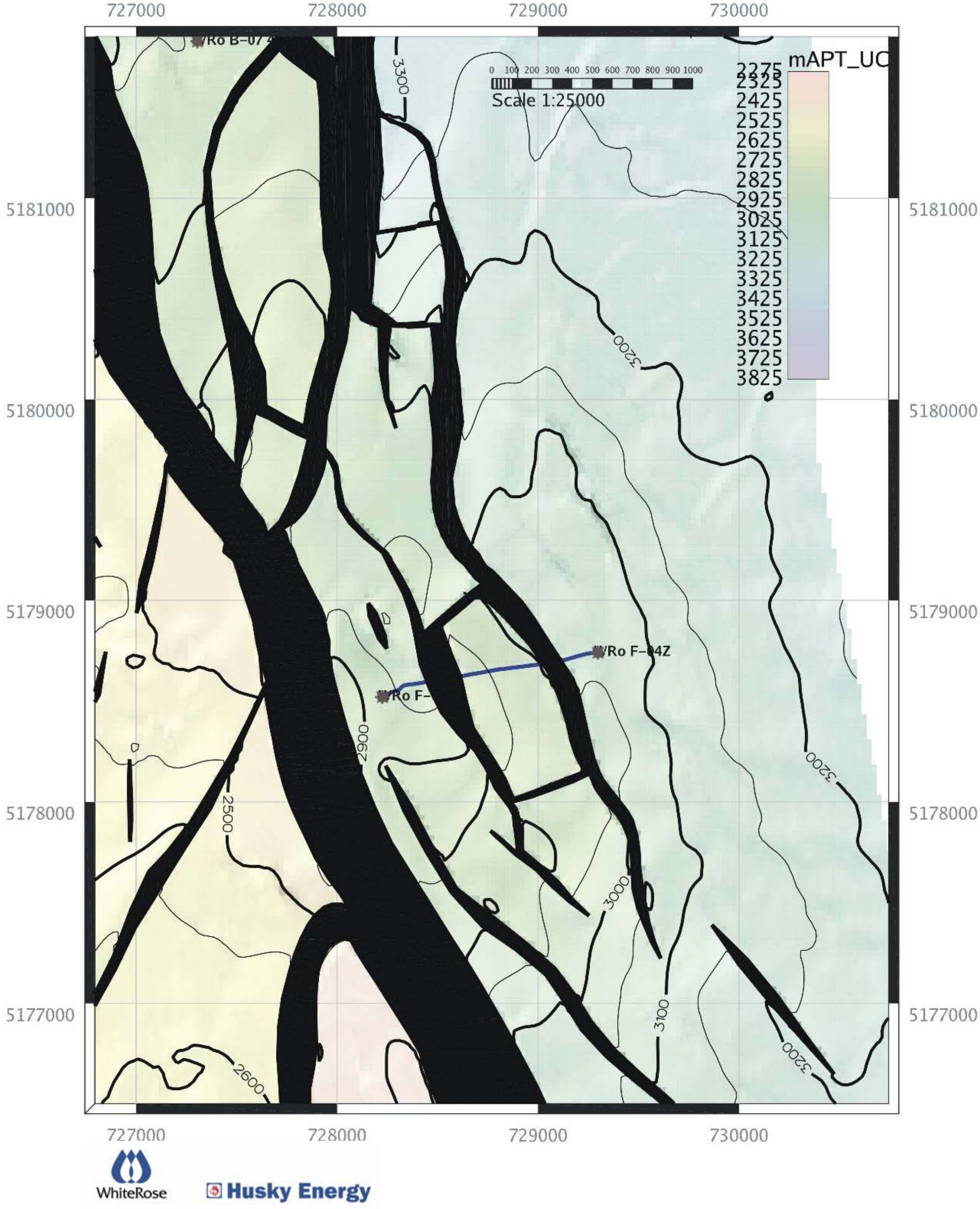


Figure 3.8: Net sand thickness in the SWRX region.

As presented in the White Rose Development Application, three main Facies Associations (FA) and some diagenetic components are identified at White Rose, and these extend into the SWRX region:

1. FA1: Lower Shoreface Storm Deposits. Consisting of well sorted very fine grained sandstone, this FA is the main reservoir rock type in the region. Facies encountered within this grouping are low-angle (hummocky to swaley), laminated sandstone, massive sandstone, and parallel laminated sandstone. Varying amounts of shell bioclastic and sideritised shale ripup clasts are present as lags along basal scour contacts.

2. FA2: Lower Shoreface Fairweather Deposits. These intervals consist of heavily bioturbated siltsone to silty-sandstone to sandstone. Primary sedimentary structures are rarely preserved.

3. FA3: Marine Deposits. Representing the distal component of White Rose region deposition, the facies types for this group are laminated and massive silty-shale to shale, with some minor bioturbated intervals.

4. Diagenetic Components. Although not representative of a primary depositional feature, due to the abundance of secondary components in the reservoir rock, these have been separated into three groups. Calcite cement is dominant within the Ben Nevis Fm and consists of two types of nodules. Calcite nodules are defined by their round edges as seen in both core and on image logs and likely have poor lateral continuity. Calcite nodules can also be concentrated along shell lag intervals, appearing more lenticular and usually exhibiting convolute edges. Although more continuous than singular nodules, these occurrences are not likely to form intra-reservoir barriers. A third type, siderite nodules, are not significant in terms of reservoir proportion but are locally present, commonly within mud-lined trace fossils.

These Facies Associations have been incorporated within the static reservoir model and the resultant dynamic model used in simulation.

3.2 Geophysics

Results of the -F04 and F-04z wells lead to a downward shift in the top reservoir surface. The primary difference was related to the pre-drill interpretation being a cycle higher than where the actual post-drill top was encountered in both wells. This is the main difference in the current seismic interpretation relative to that presented in the DA. Although several interpreters have made slight adjustments to the pre-existing interpretation, no further material changes have resulted.

The current velocity model being used for the White Rose field is a two layer VoK model with Tertiary (sea level to base tertiary) and Upper Cretaceous (Base Tertiary to mAPT_UC) velocity intervals, and includes data from the F-04 well. Current uncertainty between prognosed and actual results in the main development region place the velocity model uncertainty at between +/- 35 m for the top reservoir and +/-15 m for the base reservoir.

Figures 3.9, 3.10, and 3.11 illustrate seismic sections through the SWRX area, highlighting the top and base reservoir as well as the density of faulting encountered in the Aptian-Albian section.

Figure 3.9 - Seismic Section at Northern Extent of the SWRX Area (Line runs west to east intersecting the Amethyst ridge, Terrace, and SWRX blocks)

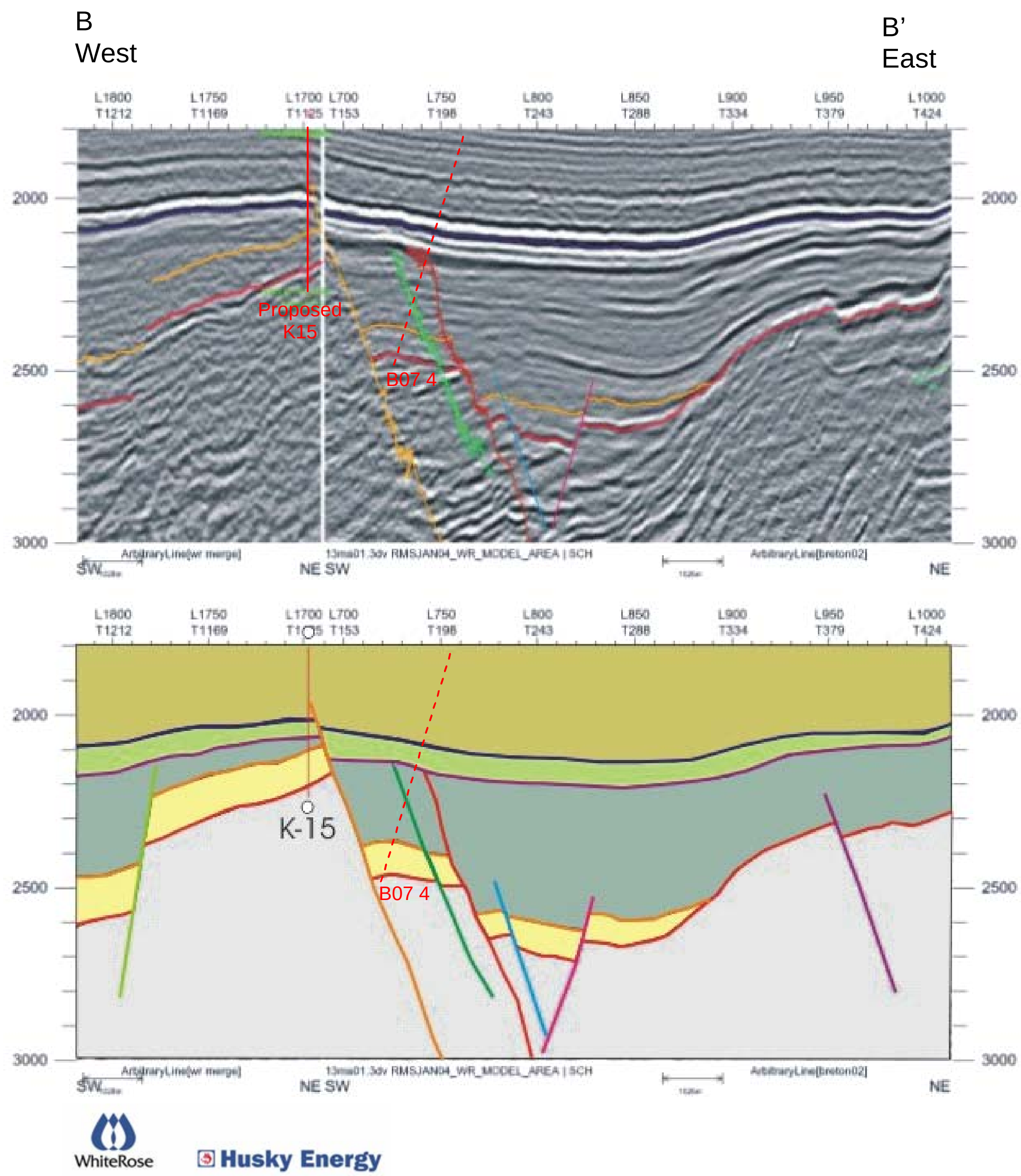


Figure 3.10 - Seismic Section at the Central Extent of the SWRX Area (Line runs west to east intersecting the F-04 and F-04z wells in the SWRX blocks)

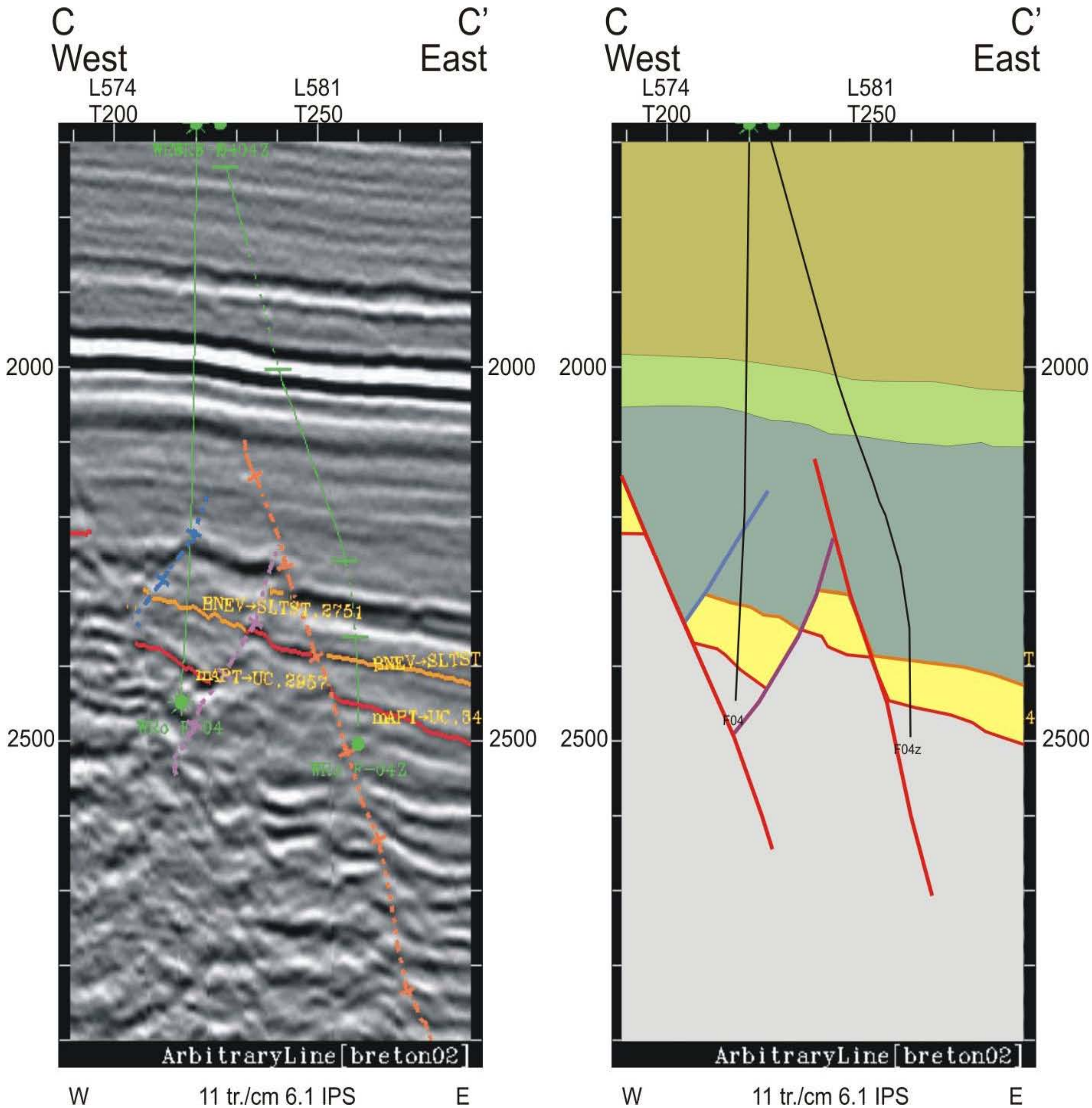
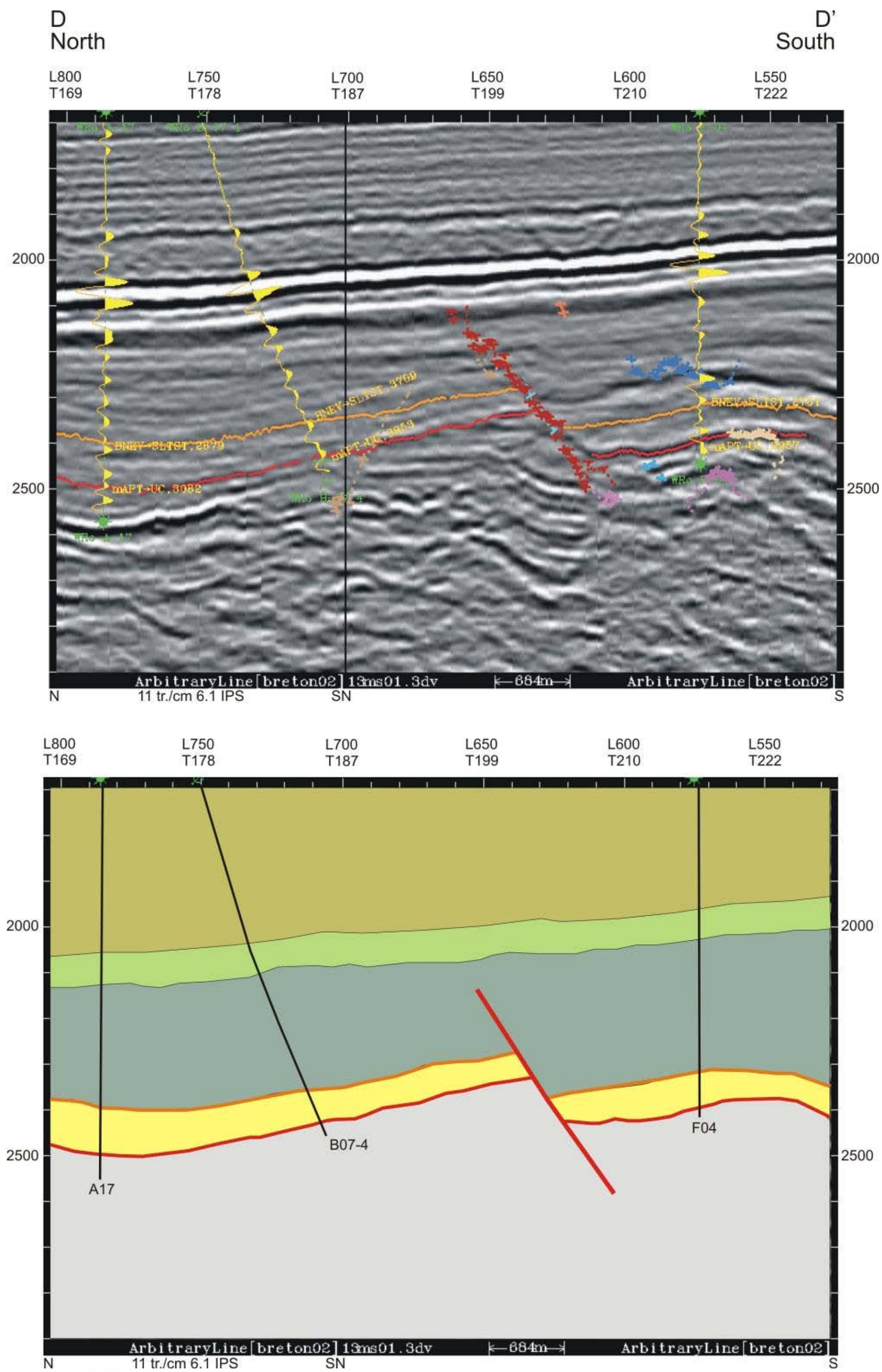


Figure 3.11 - Seismic Section at the Central Extent of the SWRX Area (Line runs north to south intersecting the A-17,B-07 4, and F-04 wells in the terrace and SWRX blocks)



3.3 Petrophysics

Petrophysical summaries for all wells within the White Rose Development region and SWRX are listed in Tables 3.1, 3.2, 3.3, and 3.4. For this Development Plan Amendment, the F-04 and F-04z wells are the relevant sources of information for the southeastern extents of the Ben Nevis reservoir. In both of these wells, thick, porous hydrocarbon-bearing sandstone was encountered, with reservoir properties being similar to the development/delineation wells of the White Rose Development.

White Rose F-04 was drilled in 2003 to delineate the SWRX region. A thick sand interval with a large gas zone (118 m) and thin oil zone (19 m) at its base was encountered (Figure 3.12). Porosity and permeability were in the same range as the Ben Nevis reservoir in the White Rose Development region, but did trend towards the higher side of the ranges.

The sidetrack to F-04, White Rose F-04z (Figure 3.13), was then drilled into a structurally lower block in order to confirm the oil-water contact expected in the region. This well encountered no significant gas leg, and 27 m of oil pay before reaching the oil/water contact (OWC) at a depth of 2968 m top depth (TVD ss). Again porosity and permeability where found to be in the same ranges sampled in the White Rose Development region. This well encountered 183.3 m of gross interval, with 114 m being of reservoir quality. Figures 3.14 and 3.15 are petrophysical summaries of A-17 and B-074 for comparative purposes.

Table 3.1 - Petrophysical Summary for the Gas Leg Intervals

Region	Well	Type	Top Depth (m TVD ss)	Gross Thickness (m)	Net:Gross	Porosity (%)	Permeability (mD)
	Gas Leg						
White Rose Development Region	H20	Delineation					
	B19z	Delineation	2857.2	43.6	0.14	12.8	34.7
	B19	Delineation	2779.5	94	0.27	14	68.2
	E09	Delineation	2784	82	0.22	13	41
	L08	Delineation	2771.2	102	0.46	15.6	92.6
	E18 1	Injector	N/A	N/A	N/A	N/A	N/A
	E18 2	Producer	N/A	N/A	N/A	N/A	N/A
	E18 3	Injector	N/A	N/A	N/A	N/A	N/A
	E18 4	Producer	N/A	N/A	N/A	N/A	N/A
	A17	Delineation	2854.5	19.5	0.20	15	91.3
	B07 1	Injector	2758.53	113	0.42	16.3	139.5
	B07 2	Producer	N/A	N/A	N/A	N/A	N/A
	B07 3	Producer	N/A	N/A	N/A	N/A	N/A
	B07 4	Injector	2752.46	157.5	0.48	16	125.5
	B07 5	Producer	N/A	N/A	N/A	N/A	N/A
	B07 6	Injector	2819.03	66	0.01	12.5	33.7
	B07 8	Injector	2851.88	20.52	0.23	11.5	25
	B07 9	Injector	N/A	N/A	N/A	N/A	N/A
SWRX	F04	Delineation	2700.06	191.3	0.62	17.2	140.5
	F04z	Delineation	2881.98	6	0.21	15.8	95.4

Table 3.2 - Petrophysical Summary for the Oil Leg Intervals

Region	Well	Type	Top Depth (m TVD ss)	Gross Thickness (m)	Net:Gross	Porosity (%)	Permeability (mD)
	Oil Leg						
White Rose Development Region	H20	Delineation					
	B19z	Delineation	2893.56	128	0.38	15.4	86.9
	B19	Delineation	2871.9	129.4	0.74	16	114.63
	E09	Delineation	2869.4	138.2	0.73	16	72.6
	L08	Delineation	2872	137.7	0.83	17	133
	E18 1	Injector	N/A	N/A	N/A	N/A	N/A
	E18 2	Producer	N/A	2071.6	0.86	17	140
	E18 3	Injector	N/A	N/A	N/A	N/A	N/A
	E18 4	Producer	N/A	1247	0.88	17	130
	A17	Delineation	2874.4	125.3	0.74	16.4	99
	B07 1	Injector	2871.52	113.75	0.80	16.5	140.5
	B07 2	Producer	N/A	1102	0.80	16	140.5
	B07 3	Producer	N/A	1075	0.91	17	170
	B07 4	Injector	2858.94	131.5	0.76	17	156
	B07 5	Producer	N/A	1447	0.85	17.8	146
	B07 6	Injector	2871.99	106.8	0.78	17	172
	B07 8	Injector	2871.54	122	0.81	15.2	103
	B07 9	Injector	N/A	N/A	N/A	N/A	N/A
SWRX	F04	Delineation	2888.26	42	0.46	16.6	126.05
	F04z	Delineation	2887.94	79.5	0.34	17	142.2

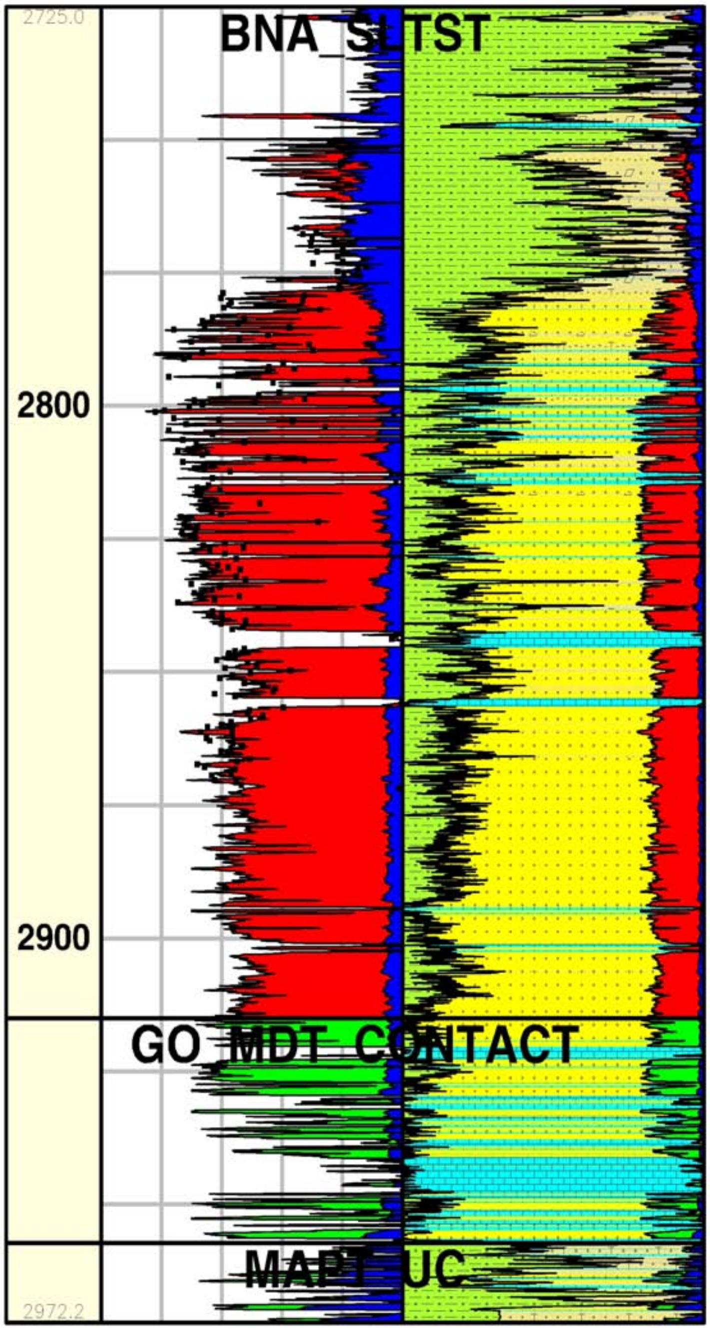
Table 3.3 - Petrophysical Summary for the Water Leg Intervals

	Water Leg						
	Well	Type	Top Depth (m TVD ss)	Gross Thickness (m)	Net Sand :Gross	Porosity (%)	Permeability (mD)
White Rose Development Region	H20	Delineation					
	B19z	Delineation	3004.81	191.6	0.77	16	110.7
	B19	Delineation	2999.9	110.5	0.74	15.6	91.36
	E09	Delineation	3008.3	111.5	0.75	15	69
	L08	Delineation	3009	63	0.67	14.6	68.1
	E18 1	Injector	N/A	N/A	N/A	N/A	N/A
	E18 2	Producer	N/A	N/A	N/A	N/A	N/A
	E18 3	Injector	N/A	1352	0.73	15	75.7
	E18 4	Producer	N/A	N/A	N/A	N/A	N/A
	A17	Delineation	3000	58	0.71	16	85
	B07 1	Injector	N/A	N/A	N/A	N/A	N/A
	B07 2	Producer	N/A	N/A	N/A	N/A	N/A
	B07 3	Producer	N/A	N/A	N/A	N/A	N/A
	B07 4	Injector	N/A	N/A	N/A	N/A	N/A
	B07 5	Producer	N/A	N/A	N/A	N/A	N/A
	B07 6	Injector	2998.45	66.5	0.65	16.7	157
	B07 8	Injector	2992.62	42.28	0.70	14.7	87
	B07 9	Injector	N/A	454.9	0.75	16.5	144.8
SWRX	F04	Delineation	N/A	N/A	N/A	N/A	N/A
	F04z	Delineation	2968.23	97.4	0.77	17.6	156.2

Table 3.4 - Petrophysical Summary for the Entire Ben Nevis Interval

	Total Ben Nevis Interval						
	Well	Type	Top Depth (m TVD ss)	Gross Thickness (m)	Net Sand :Gross	Porosity (%)	Permeability (mD)
White Rose Development Region	H20	Delineation					
	B19z	Delineation	2857.2	362.4	0.63	15.5	95
	B19	Delineation	2779.5	330	0.64	15.7	96.5
	E09	Delineation	2784	335.9	0.63	14.6	66.3
	L08	Delineation	2771.2	300.9	0.71	16.3	109.8
	E18 1	Injector	2840.42	242	0.78	16	91.6
	E18 2	Producer	N/A	N/A	N/A	N/A	N/A
	E18 3	Injector	N/A	N/A	N/A	N/A	N/A
	E18 4	Producer	N/A	N/A	N/A	N/A	N/A
	A17	Delineation	2854.5	203.1	0.70	16.1	92.4
	B07 1	Injector	2758.53	226.3	0.62	16.3	140.5
	B07 2	Producer	N/A	N/A	N/A	N/A	N/A
	B07 3	Producer	N/A	N/A	N/A	N/A	N/A
	B07 4	Injector	2752.46	285.5	0.62	16.5	142.5
	B07 5	Producer	N/A	N/A	N/A	N/A	N/A
	B07 6	Injector	2819.03	234.7	0.56	16.9	162
	B07 8	Injector	2851.88	183.3	0.72	15	96.8
	B07 9	Injector	N/A	N/A	N/A	N/A	N/A
SWRX	F04	Delineation	2700	232.25	0.60	17.1	138
	F04z	Delineation	2881.98	183.3	0.62	17.3	149.5

Figure 3.12 - F04 Petrophysical Summary



F-04 Summary (20051012, HR)

BNA Siltstone	***2725.0m MD***
GO_MDT_Contact	***2915.0m MD***
Base BNA Reservoir	***2957.25m MD***

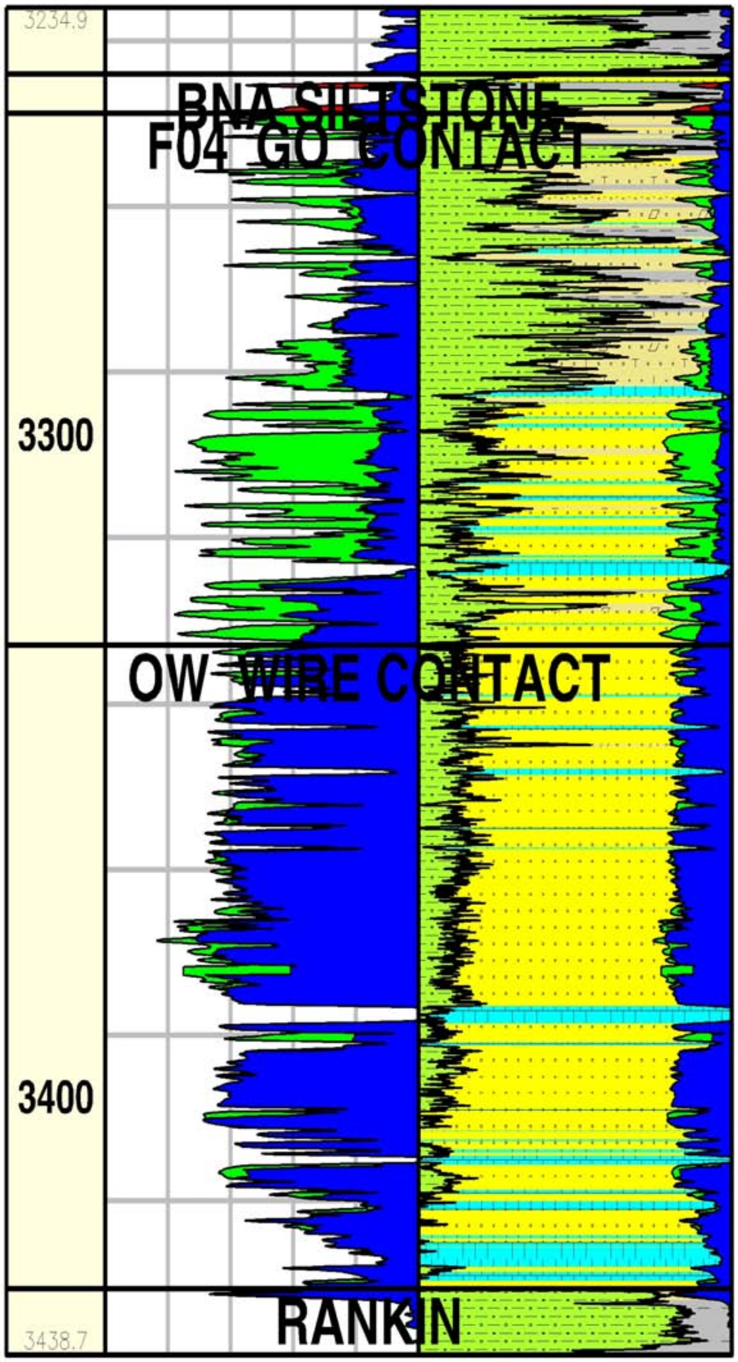
Reservoir Cutoffs
Phid>.10 v/v, Swt_Arch <=1, Vsh <.30 v/v, K >3mD
Pay Cutoffs
Phid>.10 v/v, Swt_Arch <.5, Vsh <.30 v/v, K >3mD

Reservoir: Net 138.4m MD Gross 190.0m MD N/G .63

Net Gas Pay (Avg)	118.6m MD (N/G .62) Phid .172v/v, Swt .11 v/v, Vsh 0.002 v/v, K 140.5 mD
Net Oil Pay (Avg)	19.3m MD (N/G .46) Phid 0.166v/v, Swt 0.10 v/v, Vsh .01 v/v, K 126.05 mD

WhiteRose Husky Energy

Figure 3.13 - F04z Petrophysical Summary



F-04Z Summary (20051014, HR)

BNA Siltstone	***3245.0m MD 2905.0m TVD***
F04_GO_Contact	***3251.0m MD 2910.9m TVD***
OW_WIRE_CONTACT	***3331.6m MD 2991.2m TVD***
Base BNA Reservoir	***3428.7m MD 3088.3m TVD***

Reservoir Cutoffs
Phid>.10 v/v, Swt_Arch <=1, Vsh <.30 v/v, K >3mD
Pay Cutoffs
Phid>.10 v/v, Swt_Arch <.5, Vsh <.30 v/v, K >3mD

Reservoir: Net 114.0m TVD Gross 183.3m MD N/G .62

Net Gas Pay (Assumed) 1.26m TVD (N/G .21)
(Avg) Phid .158v/v, Swt .32 v/v,
Vsh 0.03 v/v, K 95.4 mD

Net Oil Pay 27.0m TVD (N/G .34)
(Avg) Phid 0.17v/v, Swt 0.30 v/v,
Vsh .06 v/v, K 142.2 mD

Water Leg 75.0m TVD (N/G .77)
(Avg) Phid 0.176v/v, Swt N/A
Vsh .05 v/v, K 156.2 mD

WhiteRose Husky Energy

Figure 3.14 - B07-4 Petrophysical Summary

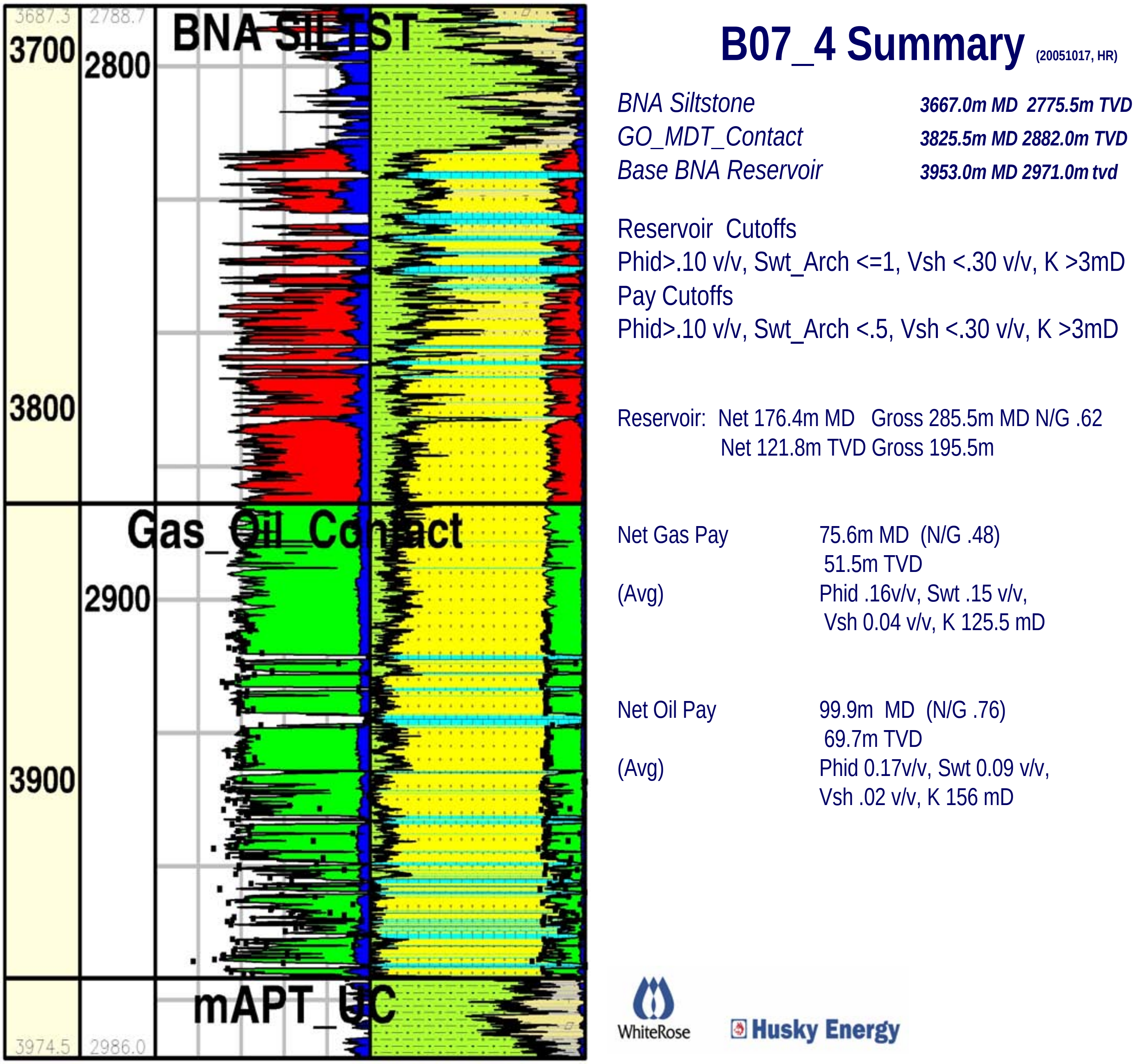
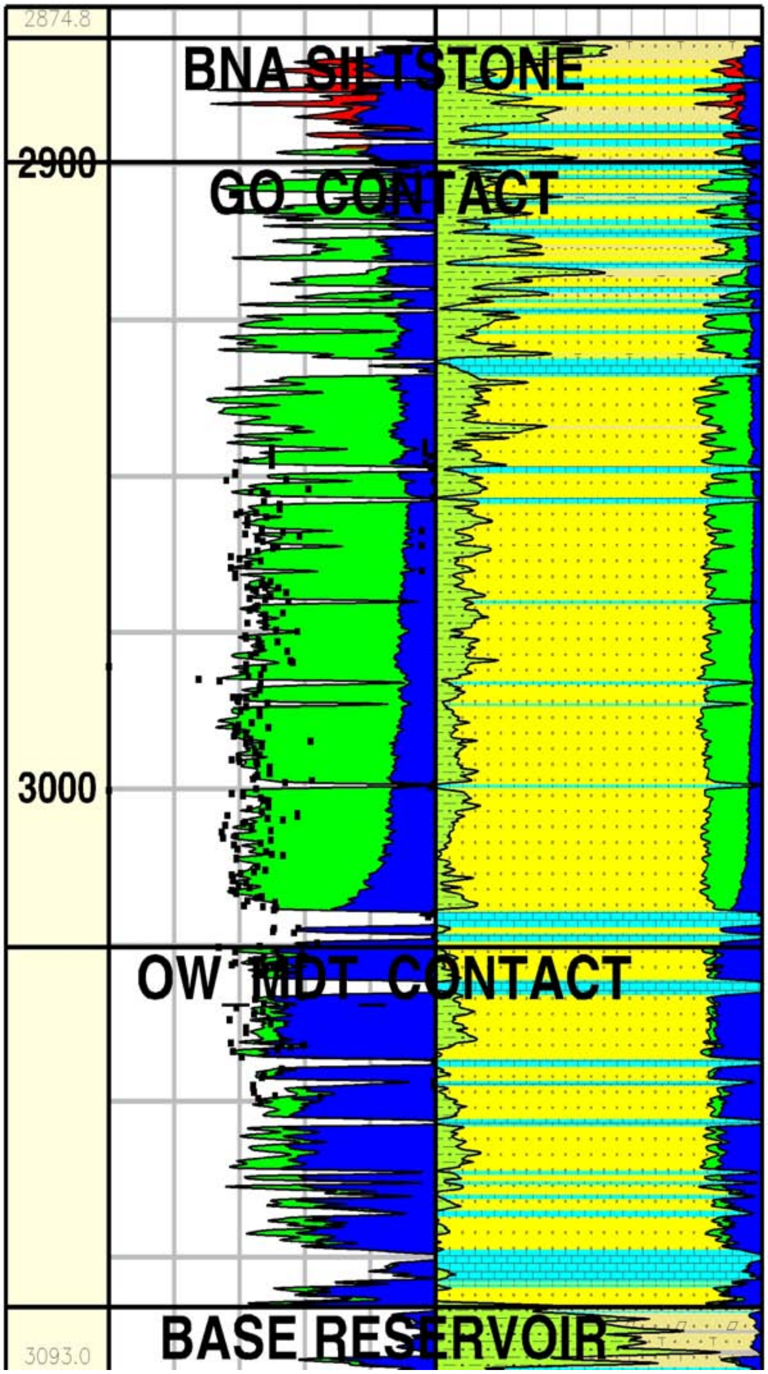


Figure 3.15 - A17 Petrophysical Summary



A17 Summary (20050928, HR)

BNA Siltstone	*2879.8m MD 2854.5m TVDSS*
GO_CONTACT	*2899.7m MD 2874.4m TVDSS*
OW_MDT_CONTACT	*3025.3m MD 3000.0m TVDSS*
Base BN (mAPT_UC)	*3083.0m MD 3057.6m TVDSS*

Reservoir Cutoffs
Phid>.10 v/v, Swt_Arch <=1, Vsh <.30 v/v, K >3mD
Pay Cutoffs
Phid>.10 v/v, Swt_Arch <.5, Vsh <.30 v/v, K >3mD

Reservoir: Net 142.4m MD Gross 203.1m MD
N/G 0.70

Net Gas Pay 3.9m MD (N/G .20)
(Avg) Phid 0.15v/v, Swt .38 v/v,
Vsh 0.12 v/v, K 91.3 mD

Net Oil Pay 92.7m MD (N/G .74)
(Avg) Phid 0.164v/v, Swt 0.19 v/v,
Vsh 0.08 v/v, K 98.8 mD

Water Zone 41.0m MD (N/G .71)
(Avg) Phid .16 v/v, Swt N/A,
Vsh 0.08 v/v, K 85.0 mD

Modular dynamic formation tester (MDT) pressure points in F-04 indicate a deeper gas-oil contact then that found in the White Rose Development area. The oil and gas gradients were found to be 7.23 kilopascals (kPa)/m and 2.06 kPa/m respectively (see Section 4.1.1 for a more detailed discussion).

3.4 Resources in Place

In-place volumetric assessments are based on reservoir modeling and probabilistic simulation. Deterministic volumes are based on a single realization of the structure and geology, and use the fluid contacts encountered in the F-04 and F-04z wells (Figure 3.16).

In order to understand the effects of uncertainty in the geological interpretation on the resource-in-place numbers, a probabilistic simulation of the SWRX was completed. In order to assess the range of expected outcomes, the input variables (bulk rock volume (BRV), net to gross ratio, porosity and water saturation (Sw)) were modeled with distribution functions. The main uncertainty affecting this region, given that there are two well penetrations constraining most inputs, is BRV. In order to capture this uncertainty, the top and base horizons were adjusted in a positive and negative fashion to define a high side and low side case.

Results from this work are illustrated in Table 3.5. The P50 original oil in place is estimated at 91 mmbbl (14.5 $10^6 m^3$) and original gas in place is estimated at 175 billion cubic feet (bcf) (5 $10^9 m^3$).

Table 3.5 Probabalistic Resources in Place, SWRX

SWRX Resources				
	P90	P50	P10	
OOIP	66	91	120	mmbbl
	10.5	14.5	19	$10^6 m^3$
OGIP	130	175	220	bcf
	3.7	5	6.2	$10^9 m^3$

Figure 3.16 - Slices Through the Fluid Phase Parameter Illustrating the Fluid Contacts in the SWRX Region

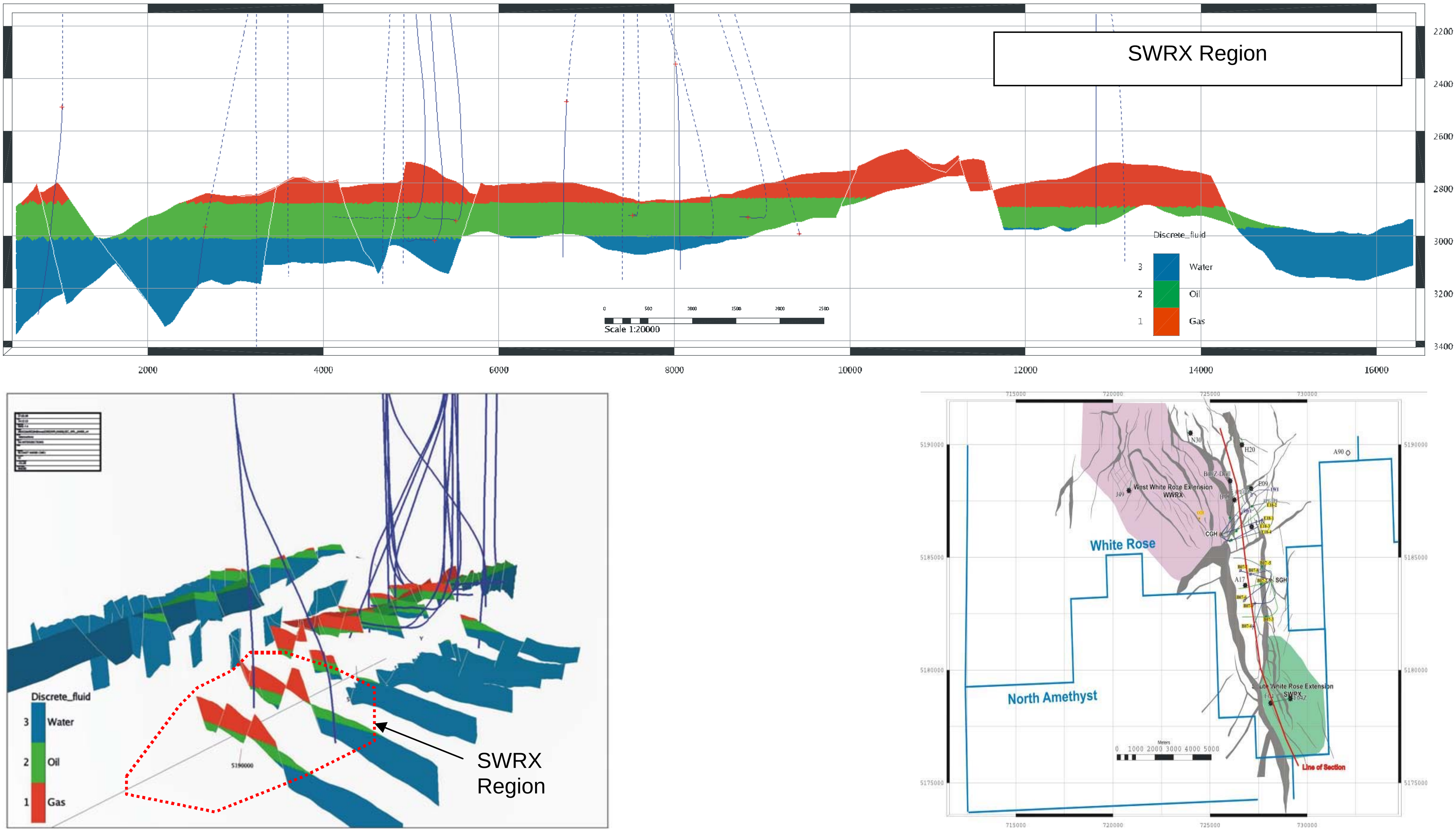
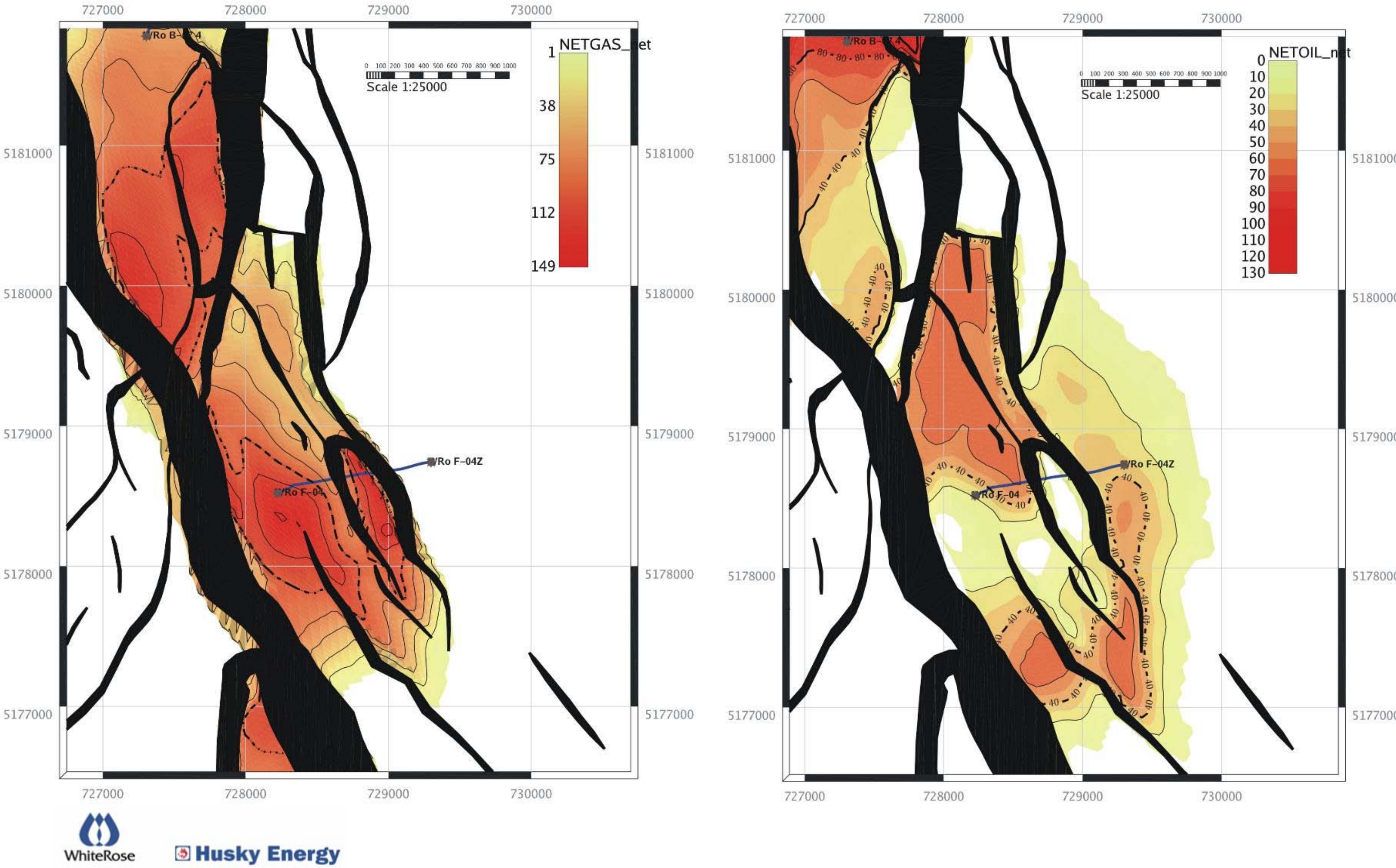


Figure 3.17 - Single Realization Output of Net Gas (left) and Net Oil (right) in the SWRX Region



4.0 Reservoir Engineering

4.1 Basic Reservoir Data

4.1.1 Reservoir Pressures and Temperatures

The reservoir pressure was measured while open hole logging with Schlumberger's MDT tool in the White Rose F-04 well. The gas gradient was 2.06 kPa/m and the oil gradient was 7.23 kPa/m. Both of these values are similar to the fluid gradients seen elsewhere in the White Rose area as shown in Table 4.1. The pressure elevation plot for the F-04 well is provided in Figure 4.1 along with other wells from the White Rose producing area.

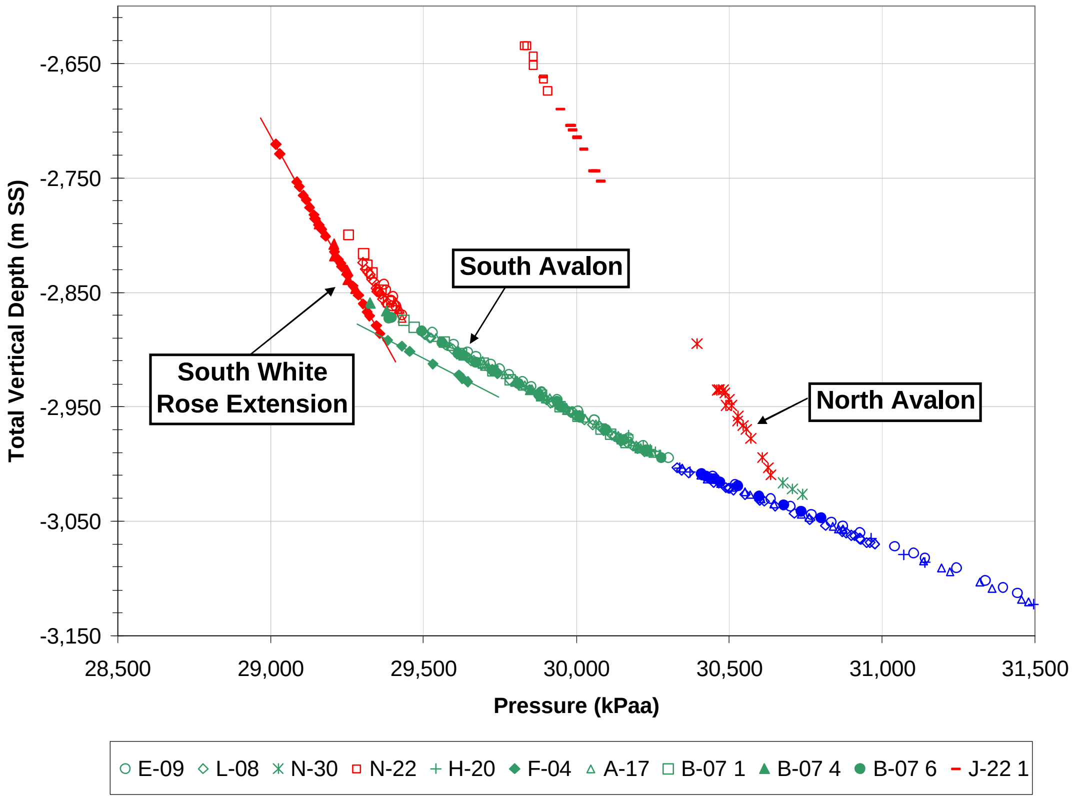
Table 4.1 - White Rose Fluid Gradients in Ben Nevis Avalon Sands

Well	Reservoir Gas Gradient (kPa/m)	Reservoir Oil Gradient (kPa/m)	Reservoir Water Gradient (kPa/m)	PVT Live Oil Gradient (kPa/m)
A-17	1.71	6.96	9.71	7.07
L-08	2.11	6.98	9.69	7.06
E-09	2.28	7.09	9.81	6.85
H-20	n/a	6.15	9.67	n/a
B-07 1	2.13	6.84	n/a	n/a
B-07 4	2.06	6.92	n/a	n/a
B-07 6	n/a	7.18	10.22	n/a
N-22	1.99	n/a	n/a	n/a
N-30	2.26	6.70	n/a	n/a
J-22 1	2.05	n/a	n/a	n/a
F-04	2.06	7.23	n/a	n/a

The gas – oil contact by intersection of the F-04 fluid gradient lines is -2888 m TVDss. The pressure at this contact is 29,400 kPa. An oil – water contact was not detected in the F-04 well. An oil – water contact was detected in the F-04Z sidetrack well. The bottom of the oil water transition zone is defined at -2968 m TVDss from open hole logs (refer to Section 3.0).

The maximum temperature detected at maximum depth during logging the F-04 well was 98^{o} C. Incorporating the reduction in temperature expected during logging due to circulation of drilling mud, the reservoir temperature was estimated to be 101^{o} C for the SWRX area.

Figure 4.1 - Pressure Elevation Plot for White Rose Area Ben Nevis Avalon Wells



4.1.2 Fluid Characterization

During open hole wireline logging of the F-04 well, bottom hole pressurized fluid samples were obtained in the gas zone. An attempt was made to obtain pressurized samples in the oil zone however the MDT tool became stuck downhole, leading to an extensive fishing operation. On the sidetrack F-04Z well, the MDT logging operation was conveyed on drill pipe rather than wireline. However, due to operational difficulties, the risk of continuing to attempt logging was considered too great to continue and oil samples were not obtained for this well.

The fluid properties for the samples taken in the gas zone of F-04 are very similar to other gas samples in the White Rose field. The reservoir fluid study results are summarized and compared to other White Rose wells in Table 4.2.

Table 4.2 - Summary of White Rose Gas Cap Fluid Properties

	N-30	**J-22 1**	**J-22 1**	**F-04**
Sample Type	Bottom Hole - MDT	Bottom Hole - MDT	Recombined Sep	Bottom Hole - MDT
Sample ID	248-06	MPSR 1359	1206 / 14002-QA	MPSR 1363
Sample Depth (m MD)		2851.3	Separator	2826.8
Mud System	WBM	SBM	SBM	WBM
Reservoir Temp (°C)	106	106	106	101
Dew Point (kPa)	30,660	30,340	28,463	29,470
Z Factor *	0.9728	0.9131	0.9740	0.9250
Viscosity (cP) *	0.0252	0.0240	n/a	0.0243
Density (g/cm3) *	0.2141	0.2256	0.1860	0.2044
MW	21.41	21.40	20.48	20.96
CGR (m^3 / 10^6m^3)	182.75	183.52	159.74	150.73
CGR (stb/mmscf)	32.55	32.69	28.46	26.85
N_2 mole fraction	0.0013	0.0037	0.0052	0.0052
CO_2 mole fraction	0.0153	0.0130	0.0108	0.0134
H_2S mole fraction	0.0000	0.0000	0.0000	0.0000
C1 mole fraction	0.8924	0.8787	0.8819	0.8743
C2 mole fraction	0.0389	0.0412	0.0429	0.0431
C3 mole fraction	0.0185	0.0215	0.0230	0.0241
i-C4 mole fraction	0.0032	0.0033	0.0035	0.0039
n-C4 mole fraction	0.0074	0.0097	0.0087	0.0096
i-C5 mole fraction	0.0015	0.0018	0.0024	0.0023
n-C5 mole fraction	0.0024	0.0030	0.0034	0.0036
$C6^+$ mole fraction	0.0191	0.0241	0.0183	0.0205
$C6^+$ MW	183.40	138.46	125.08	127.94
$C6^+$ density (g/cm^3)	0.8417	0.7920	0.7896	0.7700

* property at dew point at reservoir temperature

It is anticipated that the oil properties for the SWRX will be the same as for the main White Rose Development. Since the White Rose Development Application was submitted in 2001, all Eclipse models have been using the same pressure, volume and temperature (PVT) properties. The source of PVT properties was the analysis results of drill stem test (DST)-samples from wells A-17, L-08, and E-09. The analysis results were averaged to an initial gas-oil-ratio of 122 m^3/m^3, saturation pressure of 29,400 kPa, and an initial oil formation volume factor of 1.35 m^3/m^3.

Following a preliminary history match of the first six months of production (Nov 2005 to May 2006), new PVT property tables were found to best match the confirmed producing gas-oil ratio in wells B-07 2, B-07 3, E-18 2, and E-18 4. The new PVT tables were generated from the differential liberation experimental data sample 03-15 SEP43-02 from well A-17 after correcting the saturation pressure to 29, 405 kPa. Tabulated PVT properties are shown in Table 4.3.

Table 4.3 - Summary of White Rose Oil Fluid Properties

A17 03-15 SEP43-02 Oil Properties				A17 03-15 SEP43-02 Gas Properties		
Rs	Pressure	Bo	Oil Visc.	Pressure	Bg	Gas Visc.
(sm3/sm3)	(barsa)	(m3/Sm3)	(cp)	(bara)	(m3/Sm3)	(cp)
@ T = 106 deg.C. & Pb = 292.54 barsa corrected to 294.05 (MDT)						
0.0000	0.8946	1.0550	2.9130	0.8946	1.5187	0.0107
13.8000	9.5591	1.0960	2.0260	9.5592	0.1372	0.0135
18.0000	18.2236	1.1120	1.8970	18.2238	0.0713	0.0141
24.4000	35.5425	1.1300	1.6850	35.5430	0.0360	0.0147
39.1000	70.2005	1.1650	1.4370	70.2015	0.0178	0.0156
53.8000	104.8484	1.1990	1.2420	104.8498	0.0118	0.0168
68.4000	139.5064	1.2330	1.0940	139.5083	0.0088	0.0182
82.4000	174.1543	1.2670	0.9800	174.1567	0.0071	0.0199
97.7000	208.8022	1.3030	0.8710	208.8051	0.0060	0.0218
113.7000	243.4602	1.3410	0.7850	243.4635	0.0052	0.0241
137.5000	294.0500	1.4050	0.7076	294.0500	0.0045	0.0280
137.5000	312.0625	1.4010	0.6959	312.0625	0.0043	0.0298
137.5000	350.0000	1.3926	0.6863	350.0000	0.0040	0.0346

Three formation water samples have been taken from the South Avalon pool and are summarized in Table 4.4. Both L-08 and A-17 were drilled with water-based drilling mud and the water compositions were corrected for mud contamination. The B-07 6 well was drilled with synthetic-based mud. Considering that all wells within White Rose that encountered a water leg in the Ben Nevis Avalon sandstone fall on a common water gradient (refer to Figure 4.1), the formation water composition of the SWRX area is expected to be similar to the range listed Table 4.4.

Table 4.4 - Summary of White Rose Formation Water Fluid Properties

Ion	Water Compositional Analysis		
	Concentration (mg/L)		
	L-08	A-17	B-07 6
Na^{+}	15,000	8,505	8,500
K^{+}	700	2,310	160
Ca^{+2}	750	440	307
Mg^{+2}	100	85	29
Ba^{+2}	3.3	0.517	0.37
Sr^{+2}	120	22.3	30.9
Fe^{+2}	3.0	2.15	0.5
B^{+3}	58	37	63.9
Mn^{+3}	0.5	0.213	0.2
Cl^{-}	25,300	14,400	11,800
Br^{-}	50	43.8	55.4
I^{-}	50	<50.0	67.5
HCO_3^{-}	1,100	1,464	1,320
SO_4^{-2}	350	764	970

CO_3^-	Not Listed	Not Listed	6
OH^-	Not Listed	Not Listed	5
H_2S	Not Listed	Not Listed	Absent
Remarks: -L-08 analysis corrected for mud contamination. Data provides best estimated composition for formation water from L-08. -A-17 analysis derived from corrections to a specific water sample analysis. -B-07 6 analysis performed on a filtrate recovered from oil stained water containing sediment.			

4.1.3 Injection Fluids

The depletion plan for the SWRX area includes secondary recovery by water flood. Sea water will be injected from the Sea Rose FPSO and will be sourced and treated in the same manner as water that is currently being injected into the South Avalon pool. Since the formation water in the SWRX area is expected to be the same as in the White Rose area, no compatibility issues are anticipated to arise due to sea water injection, however as with the South Avalon Pool, chemical injection capability will be installed to mitigate scaling issues if encountered.

4.1.4 Special Core Analysis

Normalized oil-water and gas-oil relative permeability curves (Figures 4.2 and 4.3) have remained unchanged since the DA submission in 2001. The irreducible water saturation end-points were updated following the high resolution interpretation of logs and new well core data. The laminated facies endpoint was changed from 12% to 10% and the bioturbated facies endpoint was changed from 60% to 25%.

Figure 4.2 - White Rose Oil-Water Relative Permeability Curves

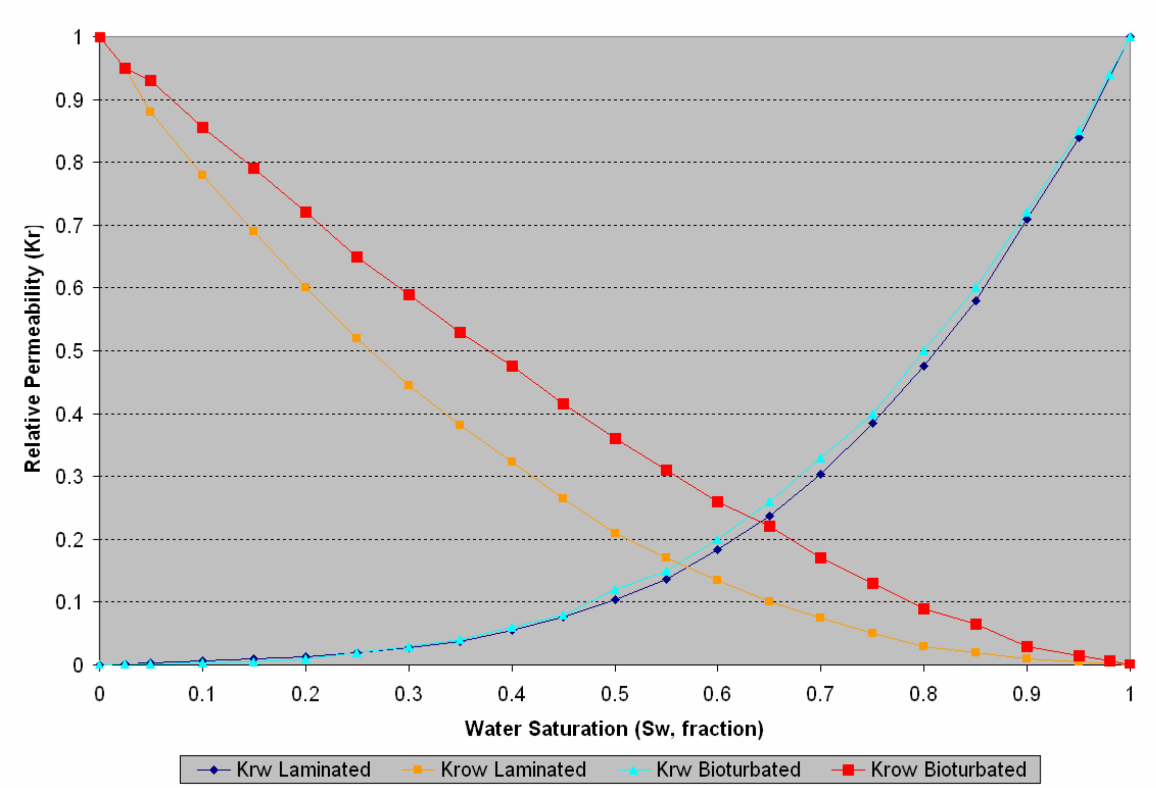
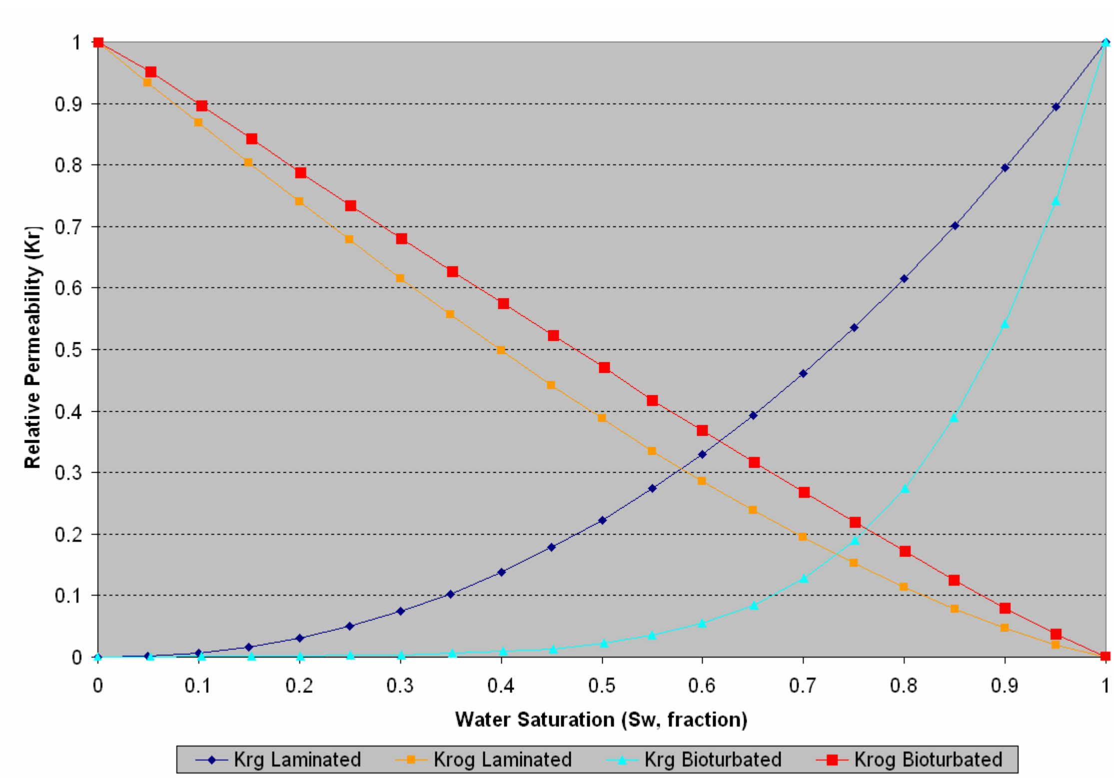


Figure 4.3 - White Rose Oil-Gas Relative Permeability Curves



4.1.5 J Function Curves

Three J function curves were used to estimate the initial water saturation profiles over depths in three distinguished rock facies (shale, bioturbated, and laminated) in the geological scale model. The shape of transition zones and values of the end-points were estimated from the log scale water saturations after high-resolution interpretation in wells A-17, L-08, E-09, E-18 1, B-07 4, B-07 1, B-07 6, F-04 and F-04Z. The following equation was used to generate the J curves:

$$J = P_C \left(\frac{K_{AIR}}{f} \right)^{1/2}$$

No surface tension was used.

$$P_C(at\,depth\,D) = 0.00981\,(OWC\ m - D\ m)\left(\Delta\, r_{OW}\ kg/m^3\right) = 0.00981\,(OWC - D)\,(995.4 - 720)$$

The Swi in each cell in the geological scale model was calculated from the J values using the same constants.

4.2 Development Strategy

4.2.1 Displacement Strategy

The displacement strategy for the SWRX is to provide water injection for pressure support in addition to active aquifer drive from the south and east of the development. Water injection will provide support for a producer in the F-04 block. The producers in the F-04Z block are anticipated to be supported by the regional acquifer.

The existence of a large water volume is possible from a geological point of view, however the connectivity of the water volume and the sustainability of water encroachment for pressure support is not definitive. This is primarily due to uncertainty in subseismic structural elements that could lead to compartmentalization of the reservoir. Current geophysical understanding of the southern region does not show the SWRX area to be segregated by faulting. Several simulation sensitivities were run regarding the aquifer size as a ratio of original oil in place (OOIP). It was found that a ratio of greater than 100 is required to provide sufficient pressure support for ultimate recoveries similar to dedicated water injectors. This is within the range of the regional water in place.

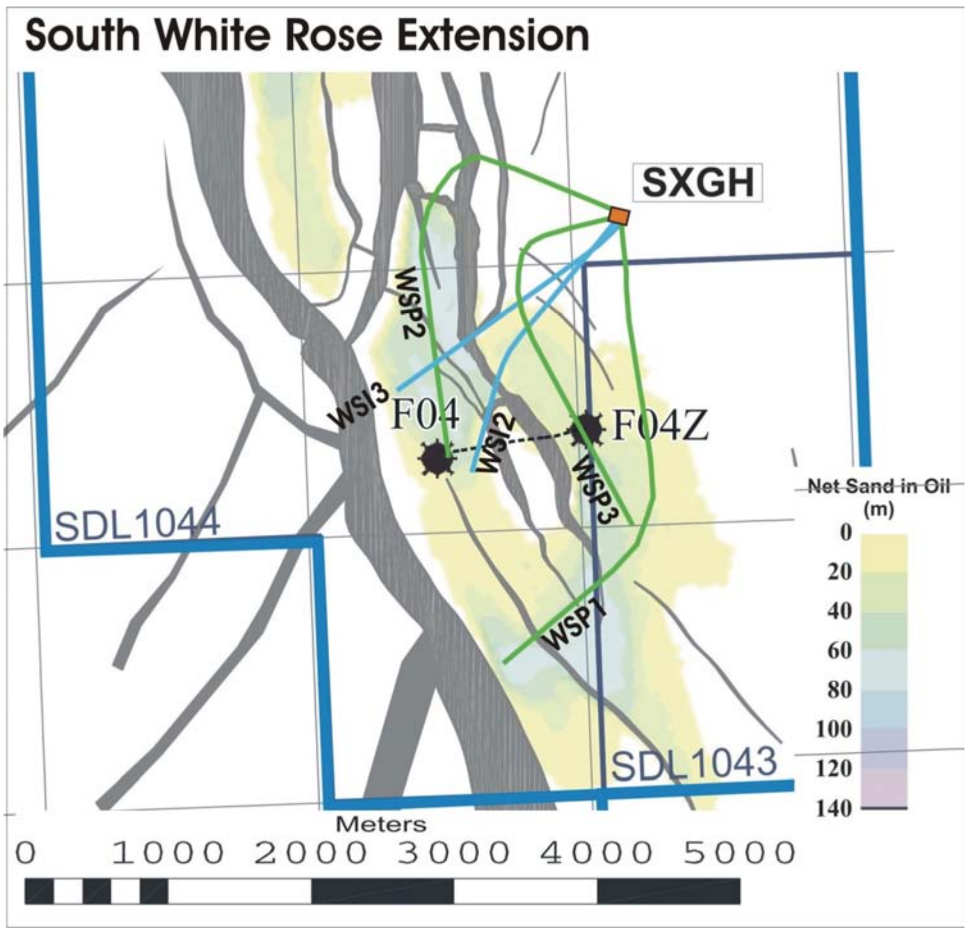
4.2.2 Development Scenario

A full field prediction model was run for the existing White Rose Development and this will be referred to as the Base Case. The SWRX wells were added to the Base Case and this full field prediction model will be referred to as the Development Case. The performance predictions for the SWRX area were determined by the difference between the Base Case and Development Case predictions.

The Base Case prediction incorporated gas lift optimization for all production wells. In the Development Case, gas lift is not included for the SWRX wells due to the high producing gas-oil ratio (GOR) (1000 to 3000 m^3/m^3) expected from these wells. The optimum gas lift injection rate in each producer was calculated by Eclipse at each time step in order to maximize the total oil production rate from the field.

A top view of the potential well locations in the SWRX for the Development Case is shown in Figure 4.4. The potential development scenario includes three oil producers and two water injectors.

Figure 4.4 Potential South White Rose Extension Well Locations



The following five wells are contemplated as potential wells for developing the SWRX F-04 and F-04Z blocks:

- F-04 Block

- Horizontal producer WSP1, 939 m long draining the southern oil region of the block. In terms of predicted oil reserves, the optimum well elevation depth in Eclipse model was found to be 2,925 m-TVDss.

- Horizontal producer WSP2, 1,349 m long draining central and northern oil regions of the block. In terms of predicted oil reserves, the optimum well elevation depth in Eclipse model was found to be 2,930 m-TVDss.

- Horizontal water injector WSI2, 777 m long injecting into the oil column (at depth 2,931 m-TVDss) in two faulted regions at the north-east and the center of the F-04 block.

- Vertical water injector WSI3 with 49 m completed interval injecting into the oil column at the north-western flank of the F-04 block.

- F-04Z Block

  - Horizontal producer WSP3, 975 m long draining the oil region west of the F-04Z well location. In terms of oil reserves, the optimum well elevation depth in Eclipse model was found to be 2,940 m-TVDss.

4.2.3 Reservoir Management Plan

The reservoir management plan for the SWRX area will be incorporated into the existing criteria currently being used to manage the White Rose South Avalon pool. Each pool in the White Rose area is at the bubble point with an overlying gas cap and underlying water leg. A voidage replacement ratio of between 1.0 and 1.2 will therefore continue to be targeted in order to maximize field ultimate recovery.

Produced gas from the SWRX area will be re-injected into the North Avalon pool for storage purposes in the same manner that excess produced gas from the South Avalon pool is currently being handled.

4.3 Reservoir Simulation

4.3.1 Simulation Model

The full field simulation model was generated from the geological model after up-scaling the cell dimensions and petrophysical characteristics. The up-scaling criteria were:

- honoring the observed reservoir characteristics at the drilled well locations;

- honoring the geologically predicted variations in reservoir characteristics within a certain stratigraphic unit; and

- no exceedance of 300,000 active cells in the simulation model.

The aerial cell dimensions were up-scaled from 50 X 50 m to approximately 100 X 100 m. As petrophysical variations within the Ben-Nevis -Sandstone mainly occur vertically, the cell thicknesses in the geological model vary from approximately 0.5 m at the South (SWRX) to approximately 3 m at the North (Block 2 & Block 5). The cell thicknesses were up-scaled by a factor of 3, from approximately 1.5 m at the South to approximately 9.0 m at the North.

The simulation model has 83 x 171 x 174 cells (total 2,469,582 cells). The number of active cells is 260,657 including the following development regions from South to North:

- South Extension (F-04 Block & F-04Z Block);
- Terrace Block;
- Central Block (Block 3, Block 1 & Block 4); and
- Block 2 & Block 5.

After the up-scaling process, the simulation model porosities, permeabilities and water saturations over depth were compared with the available log-scale petrophysical data and found to be in good agreement.

4.3.2 Production / Injection Constraints

The simulation full field model was run assuming a range of annualized production rates from 100,000, to 140,000 bopd (barrels of oil per day). In addition, the following FPSO production and injection constraints were considered:

- gas compression capacity = 4.2 X 10^6 m^3/d (148 million standard cubic feet per day (mmscf/d);
- total water injection capacity = 44,000 m^3/d (277,000 barrels per day (bbl/d);
- water injection capacity per glory hole = 30,000 m^3/d (189,000 bbl/d);
- produced water = 28,000 m^3/d (176,000 bbl/d);
- total liquids = 33,000 m^3/d (208,000 bbl/d);
- lift gas = 1.6 X 10^6 m^3/d (56 mmscf/d); and
- lift gas per glory hole = 1.19 X 10^6 m^3/d (42 mmscf/d).

Vertical flow performance (VFP) tables were generated (using Prosper software) for production wells using actual/proposed well trajectories and predicted production and pressure performance from the simulation model. VFP tables were based on both well and flow line performance. The minimum tie-in pressure for the South Avalon producers is 2,800 kPa at the FPSO topsides choke inlet. The minimum tie-in pressure for the SWRX producers is 5,500 kPa at the SDC subsea manifold. Flowing tubing head pressures were calculated at the subsea choke inlet (subsea x-mas tree).

In addition, a minimum bottom hole flowing pressure of 22,000 kPa was applied for South Avalon pool producers and 20,000 kPa for SWRX producers. The lower bottom hole flowing pressure limit for SWRX was due to the higher anticipated gas-oil ratios (1000 to 3000 m^3/m^3).

4.3.3 Production / Injection Performance

The injection-water and free-gas sweep efficiencies in each individual faulted block are shown in Figures 4.5 and 4.6, respectively. The SWRX producing GOR and water-cut (WC) profiles are much more accelerated than the other blocks. The SWRX overall performance was predicted to exceed 1,000 m^3/m^3 GOR and 50% WC before producing 20% of its original oil in place.

Figure 4.5 - White Rose Injection Water Sweep Efficiency

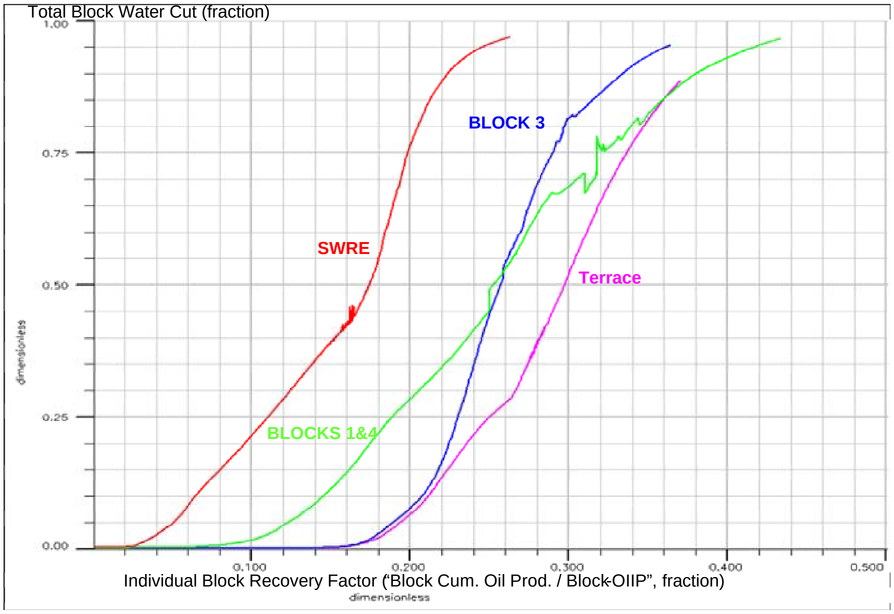
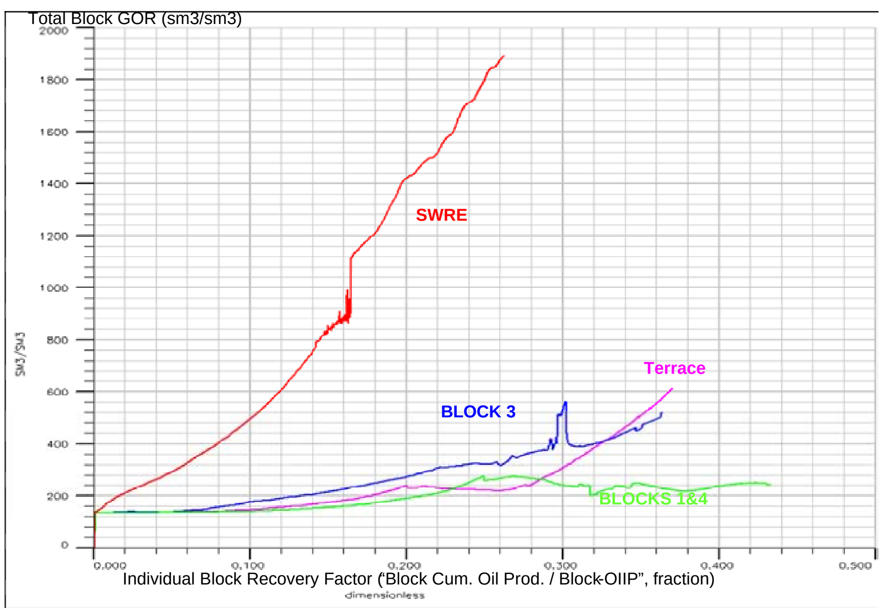


Figure 4.6 - White Rose Free Gas Sweep Efficiency



The anticipated injection water required to support the SWRX area is presented in Figure 4.7. In order to maintain a voidage replacement ratio of 1.0, influx from the aquifer existing to the south and east of the SWRX area is expected. Water encroachment of approximately 1,600 m^3/d from the aquifer to the east and approximately 6,000 m^3/d from the aquifer to the south would be required. The produced water and total produced liquid profiles for SWRX are also included in Figure 4.7. The combined White Rose Development case profiles for injected water, produced water and produced liquid are indicated in Figure 4.8. All peak values are within the topsides constraints of the SeaRose FPSO.

Figure 4.7 - SWRX Water Handling Requirements

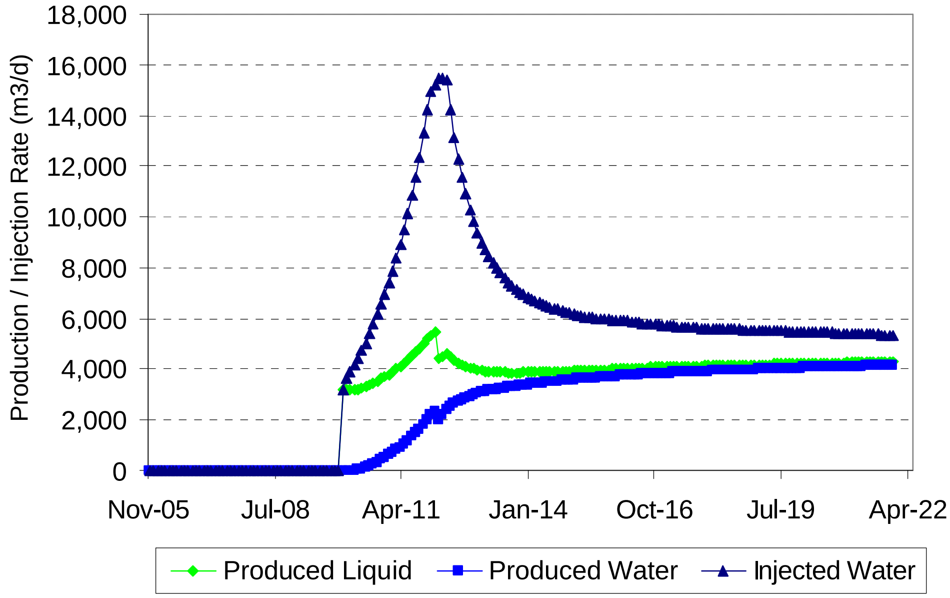
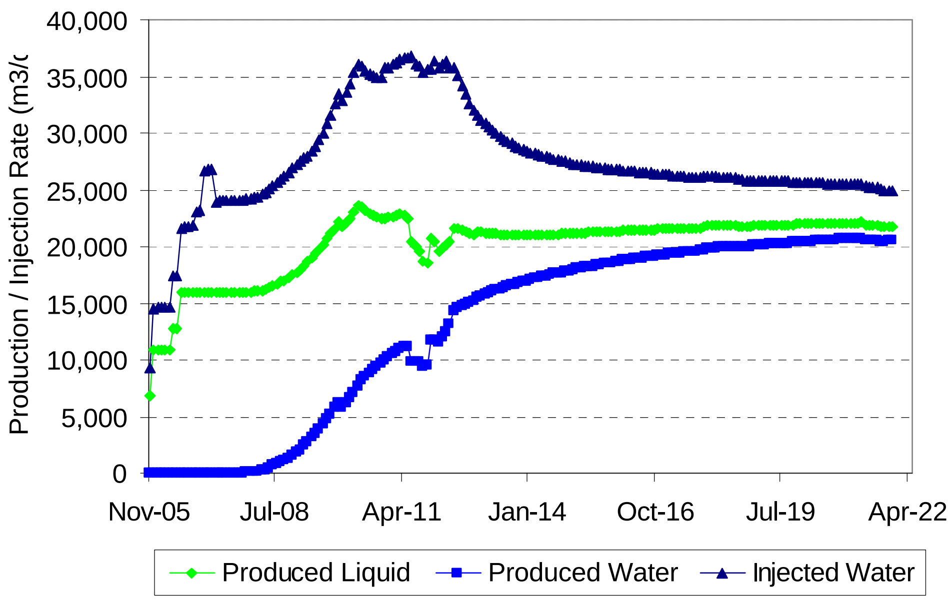


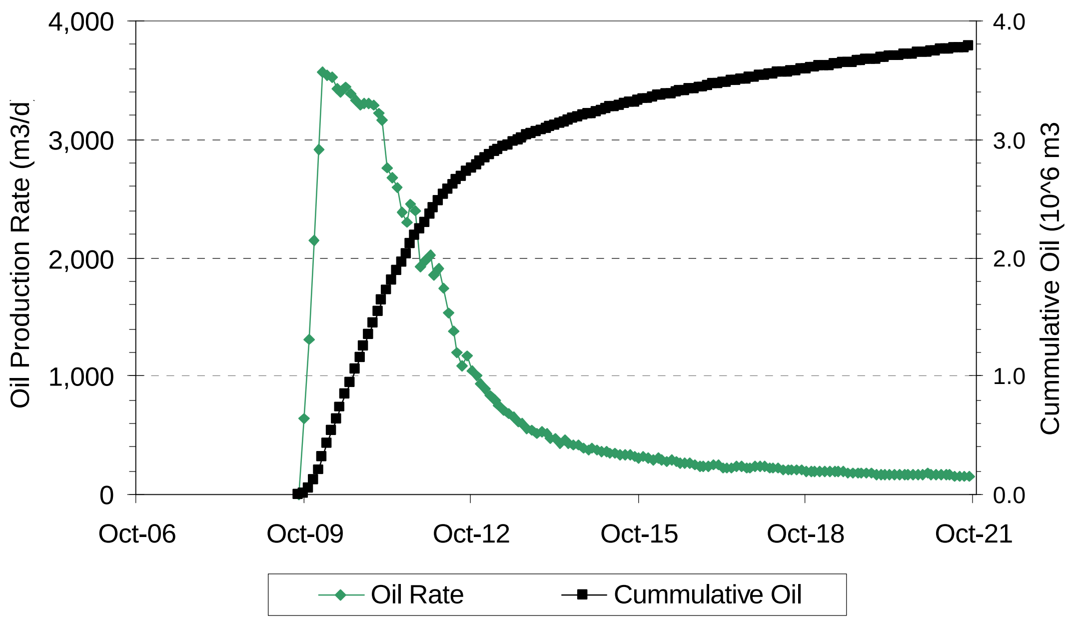
Figure 4.8 - Combined White Rose Development Water Handling Requirements



4.4 Production Forecasts

Figure 4.9 illustrates a potential production profile based on the difference between the Development Case simulation run (SWRX plus South Avalon pool) and the Base Case simulation run (South Avalon pool only). The optimum pool and well rates will be based on maximizing recovery from the entire White Rose Development. These rates would be optimized within the restrictions of Field Maximum daily rate and approved annualized daily production rate.

Figure 4.9 South White Rose Extension Oil Production Profile



4.5 Reserves Estimates

The anticipated recoverable oil from the SWRX area is between 20 and 25 MMBbl ($3.2 * 10^6 m^3$ to $4*10^6 m^3$) . The P50 volume of 24 MMbbl ($3.9 *10^6 m^3$) corresponds to a 26 % recovery factory of the P50 original oil in place of 14.3 $*10^6 m^3$ (90 mmbbl). This reserve estimate corresponds to the production forecast provided in Figure 4.9. Refer to Table 3.5 in Section 3.0 for a summary of the probabilistic reserves assessment. Table 4.5 provides a summary of the recoverable SWRX reserves.

Table 4.5 Recoverable SWRX Reserves

SWRX Reserves			
P90	P50	P10	
17	24	31	mmbbl
2.7	4	5	$10^6 m^3$

5.0 Facilities Design Criteria

5.1 Regulations, Codes and Standards

The facilities will be designed such that they comply with codes and standards, and regulatory requirements outlined in the following sub-sections.

5.1.1 Codes and Standards

Design, fabrication and erections will be certified according to the requirements of the authorities having jurisdiction in the Newfoundland and Labrador offshore area.

5.1.2 Regulatory Requirements

The installations will conform to the requirements of the following Canadian Federal and Provincial regulations that include, but are not limited to:

- Canada-Newfoundland Atlantic Accord Implementation Act (S.C. 1987, c.3);
- Canada-Newfoundland and Labrador Accord Implementation Newfoundland and Labrador Act (R.S.N.L. 1990, c. C-2).
- Newfoundland Offshore Certificate of Fitness Regulations 1995 (SOR/95-100);
- Newfoundland Offshore Area Petroleum Production and Conservation Regulations 1995 (SOR/95-103);
- Newfoundland Offshore Petroleum Installations Regulations 1995 (SOR/95-104);
- Draft Newfoundland Petroleum Occupational Safety and Health Regulations (posted on CNLOPB website on May 3, 2004);
- Newfoundland Offshore Petroleum Drilling Regulations 1993 (SOR/93-23);
- Canada Shipping Act (R.S., 1985, c. S-9);
- Offshore Waste Treatment Guidelines (August 2002);
- Newfoundland Offshore Area Guidelines for Drilling Equipment (March 1993); and
- Any and all other applicable laws.

5.2 Overall Design Requirements

The facilities design will meet the following additional requirements:

5.2.1 Fatigue

Target fatigue life for subsea equipment will be in accordance with the regulations listed in Section 5.1.2 and the requirements of ASME, API, DNV and CSA guidelines and practices.

5.2.2 Design Life Requirements

The subsea installations will be designed for a 25-year minimum service life.

5.2.3 Cathodic Protection

Cathodic protection systems will be provided for protection of subsea equipment.

5.2.4 Production Testing

Production well testing will be performed by routing individual wells through the appropriate test flowlines to the test separator on the FPSO. Real time well monitoring technology (IDUN) is employed by the White Rose Development and will be extended to the new wells at SWRX.

5.2.5 Hydrogen Sulfide Potential

The subsea system surfaces exposed to produced fluids will be designed for sour service according to NACE, MR-01-75, consistent with the present White Rose design and operating philosophies.

5.3 Environmental Criteria

The facilities design will utilize the same environmental criteria developed during the initial White Rose Development including data on wind, waves, currents, ice, seismic, and seawater properties and ambient temperatures.

Baseline environmental data for the SWRX area has already been collected as part of the current environmental effects monitoring (EEM) program. The EEM program will be reviewed to determine required changes to design as a result of development of an additional drill centre.

Development of the SWRX Tie-back will comply with all applicable government legislation, corporate policy, industry standards, existing Husky procedures, and best practices. Appropriate plans/work will be completed to address any specific environmental concerns. An environmental impact assessment for glory hole construction and development drilling is currently under review by the C-NLOPB.

5.4 Quality Assurance and Quality Control

Quality assurance and quality control will be achieved utilizing existing processes for similar White Rose activities.

5.5 Certification

Certifying Authority (CA) services will include activities during design, fabrication, installation, and commissioning as required for activities related to the SWRX Tie-back.

5.6 Decommissioning and Abandonment

The decommissioning and abandonment of the SWRX facilities will be in accordance with the established White Rose Decommissioning and Abandonment Plan.

6.0 Operations and Maintenance

There will be a requirement to shut down production during installation and commissioning of the SDC modifications and the new SWRX drill centre. However, with the exception of this shut down period, development of the SWRX Tie-back will not significantly impact the existing operations and maintenance of the White Rose Development. Similarly, the existing organizational structure (offshore and onshore) will not be impacted as a result of development of the SWRX Tie-back. The existing Operating and Maintenance Procedures will be reviewed and revised as required to include the operation and maintenance requirements of SWRX.

The Ice Management Plan will also be reviewed and updated or modified as required to reflect the additional “target” for icebergs as a result of the development of the satellite drill center. Logistics, Communications and Contingency Plans should not be impacted as a result of development of the SWRX Tie-back.

7.0 Safety Analysis

The White Rose Safety Plan approved by the CNLOPB details the approach to and results of the risk assessment process for the SeaRose FPSO. Activities associated with development of the SWRX Tie-back will utilize Husky’s formal safety assessment process. Existing Husky systems and processes for assessing risks of planned operations, modifications or changes will be used in assessing any identified risks related to the SWRX Tie-back. These processes include the Husky Management of Change Process and the Husky East Coast Process Hazards Analysis (PHA) Process. These processes will ensure that the risk profile is not compromised and the Target Levels of Safety continue to be met.

A review of the impact of the SWRX Tie-back on safety studies and plans and the mitigation measures that will be implemented has been submitted to the C-NLOPB as a separate report.

8.0 Development Costs

8.1 Capital Cost Estimates

This section discusses the capital cost estimates for facilities modifications and glory hole development, subsea production systems, and the drilling/completions cost estimates for the SWRX Tie-back. All costs presented are in 2006 Canadian dollars.

8.1.1 Assumptions for Capital Cost Estimates

The capital cost estimates have been prepared under the following set of assumptions:

- The reservoir parameters for the SWRX reserves, technical basis, and scope of work are as described in this Amendment document.
- The tie-back will be executed in accordance with the management philosophies and schedule described in this document.
- All facilities, goods, and services will be acquired on a worldwide competitive basis in accordance with the existing approved Canada-Newfoundland and Labrador Benefits Plan.

8.1.2 Capital Cost Estimates

The capital cost estimate for components of the SWRX Tie-back is approximately $595 million. Cost estimates for the components are as follows:

- Project Management and Engineering $48 M
- Drilling and Completions (5 wells) $308 M
- Glory Hole Construction $33 M
- Subsea Production System $201 M
- FPSO Modifications $5 M

8.1.3 Operating Cost Implications

The SWRX Tie-back will not significantly increase White Rose operating costs. However, in addition to fixed OPEX, the addition of a new drill centre, five additional wells, and lengthened flowlines will result in additional costs for inspection, maintenance and repairs.

Subsea inspections will increase proportionately to the count of drill centres and flowlines. Also allowances must be made for well interventions and increased chemical usage due to the flow assurance challenges associated with the longer tie-back.

Increased production and injection levels and extended plateau production will result in intensified use of existing production, processing and utility facilities, and will result in higher costs for maintenance, repairs and critical spares.

9.0 Acronyms

Term	Description
ADW	Approval to Drill a Well
bcf	billion cubic feet
Bbl/d	barrels per day
BRV	bulk rock volume
CA	Certifying Authority
C-NLOPB	Canada-Newfoundland and Labrador Offshore Petroleum Board
DA	Development Application
DST	drill stem test
EEM	environmental effects monitoring
EHMUX	electro-hydraulic multiplex umbilical
FA	facies associations
FPSO	Floating Production, Storage and Offloading Facility
GOR	gas oil ratio
Swi	irreducible water saturation
kPa	kilopascals
MDT	modular dynamic formation tester
MMbbls	million barrels
mmscf/d	million standard cubic feet per day
N:G	net to gross ratio
OOIP	original oil in place
OWC	oil/water contact
PHA	Process Hazards Analysis
PVT	pressure, volume, temperature
ROV	remotely operated vehicle
SDC	Southern Drill Centre
SGH	Southern Glory Hole
SWRX	South White Rose Extension Tie-back
Sw	water saturation
TVDss	true vertical depth subsea
VFP	vertical flow performance
WC	water cut