STAFF ANALYSIS
OF THE
WHITE ROSE DEVELOPMENT PLAN
AMENDMENT APPLICATION

WHITE ROSE EXTENSION PROJECT

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1.0 PURPOSE

The purpose of this document is to provide the Board with an assessment of Husky Oil Operations Limited (Proponent) White Rose Development Plan Amendment (DPA) for the White Rose Extension Project. This analysis considered safety, operations, environment and resource management aspects of the Development Plan amendment application.

This staff analysis does not consider any benefits or socio-economic aspects of the proposed project. These matters are assessed in a separate Benefits Plan prior to making a decision on the Development Plan. This approach is consistent with section 45(2) of the Atlantic Accord Acts.

2.0 EXECUTIVE SUMMARY

On October 21, 2013 Husky Energy (Proponent) submitted to the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) on behalf of its co-venturers Suncor Energy and Nalcor Energy – Oil and Gas the following documents in support of the amendment to the existing White Rose Development Plan:

- White Rose Extension Project – White Rose Development Plan Amendment (October 2013)
- White Rose Extension Project – Socio-Economic Impact Statement and Sustainable Development Report (October 2013)
- White Rose Extension Project – Wellhead Platform Concept Safety Analysis (October 2013)
- White Rose Extension Project – White Rose Canada-Newfoundland and Labrador Benefits Plan Amendment (October 2013)

The documents describe the Proponent's intention to build a wellhead platform (WHP) concrete gravity base structure drilling facility which will be installed in the area to the west of the White Rose field to develop oil resources primarily from the West White Rose pool beginning in late 2018. This project is referred to as the White Rose Extension Project.

In selecting this development option, the Proponent undertook a review of possible concepts for the White Rose Extension Project (WREP). Two potential concepts were analyzed:

1. Subsea wells tied back through a subsea drill centre in conjunction with the *SeaRose FPSO* and existing White Rose Field infrastructure; and
2. WHP in conjunction with the *SeaRose FPSO* and existing White Rose Field infrastructure.

The Proponent evaluated these two modes of development by assessing such factors as facility costs, production profiles and development drilling options. Based on this assessment, the Proponent's preferred concept was the WHP.

The Proponent outlined the following key factors that contributed to selection of the WHP option:

- Reduced drilling and completion costs
- Reduced drilling costs on WHP facilitated higher well count
- Increased functionality on WHP provided more drilling options in highly complex reservoirs
- Ability to develop smaller pools which increases ultimate recovery
- Increased ultimate recovery and production acceleration from the use of well stimulation, artificial lift and other technological capabilities afforded by dry tree access.

The staff concurs with the selection of this development approach.

The main function of the WHP is to provide 'dry tree' drilling and completions. All reservoir fluids produced to the WHP will be transported to the *SeaRose FPSO* for processing. Unlike the Hibernia gravity based structure, there will be no oil storage on the WHP.

Upon receipt of the development plan amendment application documents above, staff reviewed the documents for completeness. Based on its review, staff requested additional information in letters dated January 31, 2014 and April 24, 2014. Information provided by the Proponent in response to these letters was assessed by staff and in June 2014 the documents were deemed sufficiently complete. The Proponent then resubmitted the following documents which are considered "the Application" and are the subject of this analysis:

- White Rose Extension Project – White Rose Development Plan Amendment (June 2014)
- White Rose Extension Project – Socio-Economic Impact Statement and Sustainable Development Report (June 2014)
- White Rose Extension Project – Wellhead Platform Concept Safety Analysis (June 2014)
- White Rose Extension Project – White Rose Newfoundland and Labrador Benefits Plan Amendment (June 2014)
- White Rose Extension Project –Development Application Summary (June 2014)

In considering the proposed project, the Board decided that a public review was necessary. So, in June 2014 the Board announced the Dr. Leslie Harris Centre of Memorial University perform the public review on behalf of the Board. The public review began on June 12, 2014 and the public information sessions where held on June 24, 2014 in Placentia and June 25, 2014 in St. John's. The public review comment period ended on September 10, 2014 and the final public review report (see Appendix A) was submitted to the C-NLOPB on September 23, 2014.

The outcomes of the public review are part of the Application and are considered in the staff's analysis and the Board's decision.

Staff reviewed the Application from a resource management, safety, operations, environment, benefits and socio-economic perspectives. It should be noted that the staff analysis for the benefits and socio-economic aspects of the Application are in a separate Benefits Plan staff analysis.

Resource Management

The Application proposes development of the West Pool, North Pool and Blocks 2 and 5 of the South Pool from the WHP. As the West Pool has the largest reserves of all these pools, it will be the primary focus of the WREP. The plan also includes drilling infill development wells in the currently producing Terrace and Central Blocks of the South Pool from the WHP.

In order to reduce uncertainty about the development feasibility of the West Pool, the Proponent submitted the "White Rose Development Plan Amendment, West White Rose – Pilot Scheme" to the Board in 2009 and the Board approved the DPA in Decision 2010.01. The pilot scheme allowed the Proponent to acquire static and dynamic production and injection data that have provided a better understanding of the West Pool and led to the submission of this Application.

Board staff reviewed the Proponent's seismic interpretations, geological models and reservoir simulation models. Staff also conducted a review of reservoir, geological and production data acquired to November 2014 and used this data to construct geological and reservoir simulation models for the South, West and North pools.

The depletion strategy for all pools to be developed from the WHP will involve water flooding, but in some cases this will be augmented with gas flooding. Additionally, electric submersible pumps and hydraulic fracturing will be considered for certain production wells should these technologies be deemed appropriate for increasing oil recovery.

Staff used geological models to calculate oil-in-place estimates for each pool. There is a discrepancy between the Proponent's and the Board's volumetric assessments for STOOIP in the West Pool and the North Pool. These differences are attributed to variations in geological and reservoir modelling approaches, petrophysical analyses and parameters varied in the uncertainty analysis. Board staff believes that the Proponent's modelling approach and resulting STOOIP volumes particularly in the West Pool are conservative, especially considering that production from the pilot scheme has been better than expected. Future drilling and production data will allow better understanding of reservoir quality and hydrocarbon volumes and will allow refinement of the models as development progresses.

There is relatively good agreement between the Proponent's and staff's STOOIP estimates for Blocks 2 and 5 of the South Pool. Minor differences can be attributed to differences in modelling approach, petrophysical analyses, and interpretation of fluid contacts.

Board staff also assessed the Proponent's reservoir engineering data including pressures, temperatures, fluid characteristics and special core analysis. Staff believes that the Proponent has provided sufficient information about reservoir engineering for the project area, and the approach to reservoir characterization is appropriate and reasonable.

In support of the Application, the Proponent submitted ECLIPSE reservoir simulation models for the West and North pools based on their geological models. The West Pool simulation model incorporated data obtained from the drilling and production of the pilot scheme producer and injector. Staff created independent reservoir simulation models for the West and North pools based on staff's corresponding independent geological models. These simulation models were developed to assist staff in evaluating the proposed depletions schemes and determining reserve estimates for the pools. Generally, staff found the Proponent's models, assumptions and proposed depletion schemes to be reasonable and appropriate.

The majority of the oil reserves to be produced from the WHP are contained in the West Pool. The Proponent estimates the total recoverable oil reserves from the West Pool to be 17.1 MMm^3 (107.6 MMbbls). Of this total, the Proponent estimates 14.8 MMm^3 (93.1 MMbbls) will be produced through the WHP while the remainder will be produced from the West Pool pilot producer via the existing field infrastructure. There is generally good agreement between staff and the Proponent's estimated recoverable oil volume from the West Pool. Staff estimates recoverable oil for the West Pool overall to be 18.6 MMm^3 (117.1 MMbbls). Of this total, staff estimates that 16.1 MMm^3 (101.1 MMbbls) will be recovered through the WHP.

Taking into account the additional reserves from the North Pool, Blocks 2 and 5 and the infill wells to be drilled in the South Pool, the Proponent indicates that 18.3 MMm^3 (115.1 MMbbls) of additional oil can be recovered from all the pools to be developed from the WHP. Staff's estimate for the total oil recoverable from the WHP is 20.5 MMm^3 (128.7 MMbbls).

It is notable that the Proponent has extended field life to 2030 for the full-field production profiles. Production to 2030 would extend field life five years beyond the original 20-year design life of the FPSO. Further work will be required by the Proponent to assess feasibility and impacts of extending the field life beyond 2025.

The Application proposes drilling of two wells for reinjection of drill cuttings. Based on the *Newfoundland Offshore Drilling and Production Regulations* disposal of oiled drill cuttings requires approval from the Chief Conservation Officer (CCO). The Proponent must address the feasibility of re-injecting large volumes of cuttings into a suitable formation, and describe how production accounting will be impacted and managed. A report containing these details and results of simulation will be required prior to submission of any Application to Drill a Well (ADW) for a cuttings re-injection well.

If the well is approved for cuttings re-injection, reports of each injection are required to be submitted to the C-NLOPB. All cuttings re-injection equipment is required to meet offshore standards and requires the approval of a certifying authority.

While the Application proposes secondary recovery by water flooding for the West Pool and other pools to be developed from the WHP, it also indicates that this mechanism could be augmented by gas injection, water-alternating gas injection (WAG) or other enhanced oil recovery methods if these methods are found to be beneficial to oil recovery. The Proponent has performed studies on enhanced oil recovery schemes for the West Pool and other pools in the White Rose Asset but, with the exception of gas flooding in the northern Terrace Block of the South Pool, did not provide simulation modelling or other forms of technical analysis in support of these studies with the Application. Staff is not opposed to the Proponent implementing these schemes, as the practice of routinely assessing EOR schemes is consistent with the requirements of the *Newfoundland Offshore Petroleum Drilling and Production Regulations*. However, before the Proponent may proceed with gas or WAG injection from the WHP, simulation modelling or some other form of technical analysis that shows there will be no detriment to oil recovery must be provided to the C-NLOPB.

With respect to natural gas development, timely delineation of the resource needs to be undertaken and a delineation plan needs to be put in place. With respect to the current Application, staff concurs with the proposed approach of using gas for oil development. In terms of regional development of gas resources on the Grand Banks, staff believes that the White Rose Asset will play a key role, since it contains a substantial proportion of discovered gas resources. Staff concurs with the Proponent and others that development of the gas resources will require basin-wide cooperation, as there are insufficient resources in any one field to justify development at this time. Staff recommends that the Proponent be required to provide a report on gas development technologies as they relate to White Rose Asset gas resources. This will assist the Board in assessing timely development of the gas resource.

Resource Management staff recommends that the West Pool pilot scheme (Decision 2010.01), consisting of the White Rose E-18 10 and E-18 11 wells, be considered to have ended, and that ongoing production and injection from these wells be allowed to continue as development wells in the West Pool. This recommendation is based on the assumption that the Proponent is moving toward timely execution of the commitments and exploitation scheme detailed in the Application. Therefore, the Board, in consultation with the Chief Conservation Officer, should evaluate whether the Proponent is meeting the commitments outlined in the Application at six-month intervals from the date of the Decision. If during such an evaluation the Board determines the commitments are not being met, production and injection from the E-18 10 and E-18 11 wells shall cease. Under these circumstances, no further production or injection from the West Pool would be permitted until a new DPA for such activity has been approved.

Should the Application not be approved, the pilot scheme will cease with no further production and injection from the E-18 10 and E-18 11 wells permitted until a new DPA for the West Pool is approved.

Staff recommends from a resource management perspective, that the Board approve the Application subject to the following conditions:

1. **That prior to drilling of any cuttings re-injection well, the Proponent must provide a report suitable to the Board describing the feasibility of injection, the impact on reservoir management and the impact on production accounting. The report must be submitted at least six months prior to ADW submission.**

2. **That prior to initiating a gas flood or WAG scheme in the West Pool or any other pool to be developed from the WHP, the Proponent must provide simulation modelling or some other form of technical analysis which demonstrates that such a scheme will not be detrimental to oil recovery.**

3. **That the Proponent submit to the Board, within three years following initiation of production from the White Rose wellhead platform:**
    - **An updated evaluation of the White Rose Asset gas resources along with a description of activities to be undertaken to evaluate the resource; and**

- **A report on the advances and limitations of technologies such as compressed natural gas, floating liquefied natural gas, pipelines, associated onshore liquefied natural gas terminals and any other currently existing commercial offshore gas technologies, and how these technologies relate to the White Rose Asset gas resources.**

4. **That the Board, in consultation with the Chief Conservation Officer, will evaluate the commitments outlined in the Application at six-month intervals commencing from the date of the Decision. If during such evaluation the Board determines the commitments are not being met, production and injection from the E-18 10 and E-18 11 wells shall cease. In such circumstances, no further production or injection from the West Pool shall be permitted until a new Development Plan Amendment for such activity has been approved.**

Safety

Pursuant to the Atlantic Accord Acts, the Board must authorize all oil and gas activities in the Canada-Newfoundland and Labrador Offshore Area. Before issuing an authorization, the Board must consider the safety of the activity as a whole, as well as the safety of its component parts. In the case of the White Rose Extension Project (WREP), the Proponent will be required to obtain authorizations for the pre-operation activities, commencing with tow-out, as well as for the operational phase.

In support of the various applications for authorization, the Proponent will need to demonstrate compliance with the provisions and conditions of the development plan amendment, the regulations, and the selected codes, standards and specifications. Before the C-NLOPB can issue any authorizations, the statutory requirements in the Accord Acts must be satisfied.The activities associated with the WREP will be subject to the C-NLOPB's assessment of safety processes.

The WREP proposes the design, construction, installation, operation and maintenance of a manned Wellhead Platform (WHP); this means the introduction of a significant new manned facility in the White Rose Field. The current development approach in the White Rose Field is the use of subsea wells that are drilled by Mobile Offshore Drilling Units (MODUs) and are operated by a Floating Production Storage and Offloading (FPSO) facility, namely the *SeaRose FPSO*.

The main function of the WHP is as a drilling and well intervention platform for dry tree/wellhead operations; this is similar to Hibernia and Hebron. However, unlike Hibernia and Hebron, production will not occur on the WHP and no crude (unproduced or produced) will be stored on the WHP; reservoir fluids will be pumped to the *SeaRose FPSO* via subsea flowlines and will be processed through the *SeaRose FPSO* production train. That is, the WHP will act as a satellite facility in support of the *SeaRose FPSO* production operations.

The Proponent has stated in the Application that the WHP is at the preliminary design stage. The Proponent has also indicated that the results of a number of activities such as model tests, studies and decisions on systems will be incorporated into the detailed design. The Proponent will be required to keep the C-NLOPB apprised of the design development, including the provision of key design philosophy documents, specifications and drawings.

The Atlantic Accord Acts requires that, before operations may be authorized, the installation shall have a Certificate of Fitness issued by a recognized Certifying Authority (CA). The *Newfoundland Offshore Certificate of Fitness Regulations* define the bodies which may act as a CA and require that a recognized CA undertake an independent examination of the design of facilities and survey the installation during construction and operation. It should be noted that the Chief Safety Officer has to be satisfied with the level of review by the CA. This is determined through a review and approval of the Scope of Work, which is a requirement of the *Newfoundland Offshore Certificate of Fitness Regulations*, and through monitoring of the certification activities. Staff will monitor and audit the activities of the CA to ensure that it carries out its independent examination of the design of facilities and survey the installation during construction and operation in accordance with the approved Scope of Work.

The Application notes that the proposed "life" for the WHP of 25 years is beyond the current design life of the *SeaRose FPSO* yet this platform will support production by the *SeaRose FPSO*. This discrepancy in life of asset needs to be addressed well in advance of reaching the current design life of the *SeaRose FPSO*. The risk rests with the Proponent if at that time they are not able to demonstrate that the life of the *SeaRose FPSO* can be extended to align with the intended life and value of the WHP. Although the Application speaks to the current functional limitations of the *SeaRose FPSO;* the Application does not provide a clear summary of the functional criteria for the various systems on the WHP.
With respect to the CGS design, The Proponent has chosen to use the ISO offshore structures standards for the design of the WHP structure. Specifically, the *ISO 19906: Petroleum and Natural Gas Industries – Arctic Offshore Structures, First Edition, 2010-12-15* pertains to the design, construction, transportation, installation and removal of offshore structures.

Limit states design methodology, equations, load and resistance factors are as specified in the ISO 19906 code as follows:

- Ultimate Limit States (ULS): resistance to extreme ice loads, Extreme Level Ice Event (ELIE);
- Abnormal (accidental) Limit States (ALS): accidental events and abnormal environmental events Abnormal Ice Level Event (ALIE);
- Serviceability Limit States (SLS): loads associated with normal functional use; and
- Fatigue Limit States (FLS): accumulated effect of repetitive actions.

In all aspects the WHP will be designed for an L1 exposure level, with the exception of the CGS shaft for iceberg impact which will be designed for an L2 exposure level iceberg impact event. The standard allows an Exposure Level L2 classification to be applied to manned-evacuated or unmanned platforms whose failure results in medium or low consequence for life, environment and asset. For greater clarity, the CGS shaft will be designed to withstand all other environmental loads based on an L1 exposure level; it is only the iceberg impact loading event that will be based on an L2 exposure level event.

Hibernia and Hebron have been built to an L1 exposure level event in respect to all environmental loads for all aspects of each platform. The Proponent's approach is a significant departure from the design philosophy for Hibernia and Hebron. In fact, the WHP has a 10 times greater likelihood, than the Hibernia or Hebron facilities, to be impacted by an iceberg that will impart a load that exceeds the design of the CGS to the extent that the CGS shaft may fail and result in the collapse of the facility.

However, the ISO standard allows for an L2 design approach if the following criteria are met:

- Ice management protocols allow sufficient time to shut-in wells and evacuate platform (i.e. the facility is unmanned at the time of the event – no persons at risk).
- All wells that can flow on their own in the event of platform failure should contain fully functional, subsurface safety valves that are manufactured and tested in accordance with applicable specifications.
- Oil storage is limited to process inventory and "surge" tanks for pipeline transfer.
- Pipelines have limited hydrocarbon release potential, due to low volume, low pressure or effective check valves or line block valves.

The Proponent has indicated that it will take a conservative approach to ice monitoring and will ensure that all persons are removed in a planned and controlled manner prior to the WHP being exposed to an L2 iceberg impact event. All wells will be constructed with two downhole safety valves. As noted above, the WHP will not have any production or storage capabilities and the production flowlines to the *SeaRose FPSO* will be designed to have limited hydrocarbon release potential. The staff will be following up on these matters with the Proponent that the above criteria are met.

With respect to the Proponent's approach to ice management, it is expected that a conservative approach to T-Time calculation and to comprehensive ice monitoring be taken to ensure that downstaffing is successfully completed well in advance of an L2 iceberg event. At this stage in the project, the Proponent would not have sufficient detailed design and operation information to allow for the completion of the associated Ice Management Plan. The Proponent has acknowledged, however, that work is required to improve the existing Ice Management Plan for the White Rose Field so as to account for a fixed platform. That is, the plan is to build in the appropriate level of conservatism in detecting and monitoring L2 or greater icebergs, based on observable parameters, and to have sufficient conservatism in downstaffing timeframes utilizing helicopter and personnel transfer methods of moving personnel off the facility in order to meet the L2 criteria of an unmanned facility at the time of an L2 event.

Staff notes that regarding drilling and completions activities the Proponent will have to address matters such as electrical submersible pumps (ESP), hydraulic fracturing and dual conductor drilling by providing additional information to staff prior to the submission of an Approval to Drill (ADW) application.

Current production operations in the Canada-Newfoundland and Labrador offshore area have all encountered significant levels of Hydrogen Sulfide (H_2S) both from reservoir souring and from onboard sources such as slops tanks and oily water handling systems. Hydrogen sulfide has also been encountered during well intervention operations. The *Newfoundland Offshore Petroleum Installations Regulations* require the installation to be equipped with a gas detection system in every part of the installation in which hydrogen sulphide gas or any type of hydrocarbon gas may accumulate. The Proponent is required to provide a robust gas detection system and further clarity of its plans for gas detection, and particularly for H_2S gas detection, should be provided.

It is noted that the Application does not speak to the minimum design criteria or timeframe that the TSR must provide a safe haven. Experience has demonstrated the threat posed by smoke entering the TSR and associated evacuation systems, including both lifeboats and the helicopter deck. A similar threat is posed by gas ingress either into the TSR or around lifeboat stations and/or the helicopter deck. Also, the Proponent has not identified in detail the specific evacuation systems for its facilities nor does the Proponent commit to using the best practicable evacuation technology. The Proponent will be required to demonstrate to the satisfaction of the Chief Safety Officer that the best practicable evacuation technology available will be utilized on the WHP.

The Proponent proposes to tow the CGS to the offshore site and then conduct topsides mating and integration in the White Rose Field. All prior development projects in the Canada-Newfoundland and Labrador offshore area, both gravity based and floating facilities, have seen this mating and integration work being completed in sheltered waters, thus minimizing the extent of integration and commissioning being conducted in the offshore area. The approach proposed has a number of areas of concern. In general, there is a lack of detail around the scope of activities, size of workforce required and timing of activities. As well, in order to undertake this approach, the Proponent is planning to use a new vessel that will be the world's largest ship of its kind but is still being built; therefore there will be limited operational history or experience with this vessel. The Proponent does not provide sufficient commentary on how this risk will be managed.

This approach will require POB accommodations capacity offshore that has not been required on any other project to date and the Application has not provided any meaningful information on how this POB capacity requirement will be handled or the implications on managing risk. The Application mentions several possible options for trying to accommodate the extra POB. One is the use of an accommodation module. The other involves utilizing POB space from the *SeaRose FPSO*, yet there is no commentary on the implications on *SeaRose FPSO* operations even though the *SeaRose FPSO* traditionally has utilized its full POB capacity for its own operations and will require use of its own POB capacity to support the necessary modifications to be able to act as a remote operation centre. However, these options are only mentioned in passing and the Application does not provide any clear plan on how the POB capacity requirements will be managed.

The lack of commentary and analysis of these matters have a significant impact on the level of understanding of the proposed approach for executing this aspect of the development project and also have significant impact on the risk profile for this project. The operator has not presented an appropriate comparative consideration of other options, such as undertaking this mating and integration activity at a deepwater site in sheltered waters as has been done with all other projects. The operator has not demonstrated that they have considered the full scope of options for undertaking mating and integration and have not demonstrated that the proposed approach is the lowest risk option in respect to safety of activity.

Staff note that the CSA concludes that risks are within the ALARP region but it does highlight that the "frequencies of hazards resulting in 3 or 4 fatalities approach the intolerable threshold". It is understood that this information will be refined as detailed design progresses and the CSA highlights the need to review the adequacy of potential risk reduction measures to prevent, mitigate and safeguard against the major risk contributors. The Proponent will have to be able to demonstrate that all reasonable efforts have been made to mitigate these risk to as low as reasonably possible. It is also noted that the CSA does not explicitly quantify risk due to dropped objects even though dropped objects is a major risk trend in the offshore and has significant consequences if not properly mitigated. The CSA proposes a number of recommendations to ensure that the assumptions made at this pre-detailed design stage are "reviewed and revised at detailed design stage, when more detailed information is available, to facilitate a more robust and representative assessment". The CSA provides a list of recommended safety studies. The Proponent notes that additional safety studies will be required during detailed design but does not provide definite commitments in this regard. The Application fails to provide either sufficient commitment to, or a strategy for, completing a detailed suite of safety studies required to support the design and provide the basis for the Safety Plan. Staff notes that other projects derived significant benefit from the development of a Safety Assessment Plan to plan, track and manage safety studies during the design of the facilities. The C-NLOPB will require that the Chief Safety Officer be informed of the actions which the Proponent proposes to take to satisfy recommendations of the safety studies, and that the Certifying Authority ensure that the recommendations have been properly satisfied.

The Proponent is expected to develop, at an early stage, a plan to document and track the suite of safety studies required for detailed design and staff believes that the plan should include the Proponent's schedule for satisfying the recommendations presented in its CSA. Further to this, staff expects that the Certifying Authority review this plan, and the studies under it, to ensure appropriate safety assessment is undertaken and implemented in the design, construction, installation and operations phases of the WREP. Staff believes that a systematic and continuous approach to the elimination or reduction of risks to people, the environment, assets and operations is required. The Proponent will be expected to keep the C-NLOPB apprised of the design development, including the provision of key design philosophy documents, specifications and drawings.

Based on the assessment from a safety perspective staff recommends to the Board that the application be approved subject to the following conditions:

1. **The Proponent submit to the Board a schedule of activities and decision points, including schedule of model tests, associated with the detailed design of the Wellhead Platform. The Proponent will submit selected test and study results to the Board as directed. The Board, in consultation with the Chief Safety Officer, will establish the date by which submissions must be made.**

2. **The Proponent submit to the Board its plans for reconciling the differences in design life for the Wellhead Platform, the *SeaRose FPSO* and the related subsea infrastructure. The Proponent must also include information, inclusive of a description of the related analysis and measures, that demonstrates to the satisfaction of the Chief Safety Officer, the rationale for any extension in the design life, including details of related verification activities by the Certifying Authority. The Board, in consultation with the Chief Safety Officer, will establish the date by which submissions must be made.**

3. **The Proponent submit to the Board a summary of the Functional Design Criteria that will be the basis of the detailed engineering design work. The Board, in consultation with the Chief Safety Officer, will establish the date by which submissions must be made.**

4. **Prior to the conclusion of detailed design, the Proponent submit a report, that is to the satisfaction of the Chief Safety Officer, which describes the scope, extent and outcome of environmental load model testing associated with the Wellhead Platform and also demonstrate that the outcome of this model testing has been appropriately dealt with in the structural design of the facility.**

5. **At least six months prior to the issuance of any authorization related to the Wellhead Platform, the Proponent submit an Ice Management Plan that is to the satisfaction of the Chief Safety Officer and that defines observable criteria for categorizing if an approaching iceberg meets an L2 or greater classification upon which shutdown and downstaffing procedures will be implemented.**

6. **The Proponent submit information, that is to the satisfaction of the Chief Safety Officer, that provides a more comprehensive understanding of the wellhead arrangements and layouts being proposed, a quantitative comparison of risk between the proposed wellhead layout for dual conductor arrangement versus mono conductor arrangement, clarity of the enhancements in protocols for managing wellbore collision avoidance and detail on design and slot management considerations resulting from a review of good industry practice of using such technology in the North Sea. The Board, in consultation with the Chief Safety Officer, will establish the date by which submissions must be made.**

7. **Prior to completion of detailed design of the Wellhead Platform gas detection system, the Proponent submit information, that is to the satisfaction of the Chief Safety Officer, that provides a more comprehensive understanding of the approach to H_2S gas detection for the Wellhead Platform and that demonstrates compliance with the *Newfoundland Offshore Petroleum Installations Regulations*.**

8. **Prior to completion of the Accommodations Module detailed design, the Proponent submit, to the satisfaction of the Chief Safety Officer, its criteria and rationale for the minimum timeframe that the temporary safe refuge (TSR) must continue to function as a safe haven and remain unimpaired as a result of any of the credible design events.**

9. **Prior to completion of the Evacuation System detailed design, the Proponent submit a report that is to the satisfaction of the Chief Safety Officer which demonstrates that the best practicable evacuation technology is being employed on the Wellhead Platform.**

10. **The Proponent submit information, that is to the satisfaction of the Chief Safety Officer, which provides a more comprehensive understanding of the layout of the facility including the layout and features of the accommodations and the lifting systems that will be employed on the facility. The Board, in consultation with the Chief Safety Officer, will establish the date by which submissions must be made.**

11. **Prior to bringing live the modified systems on the *SeaRose FPSO*, the Proponent submit updated information on people, processes and equipment, that is to the satisfaction of the Chief Safety Officer, in respect to the associated *SeaRose FPSO* Operations Authorization.**

12. **Prior to tow out of the Concrete Gravity Structure (CGS) from the dry dock, the Proponent submit a report, that is to the satisfaction of the Chief Safety Officer, which demonstrates that the proposed approach to Topsides-CGS mating and integration activities is the lowest risk option in respect to safety of activity.**

13. **At least one year prior to the Wellhead Platform operating under an authorization from the Board, the Proponent submit a Training and Competency Plan associated with operation and maintenance of the Wellhead Platform that is to the satisfaction of the Chief Safety Officer.**

14. **At least one year prior to the Wellhead Platform operating under an authorization from the Board, the Proponent submit to the Board its strategy for the development and documentation of the detailed operations and maintenance procedures and contingency plans necessary for the safe operation of the**

installation. The Proponent must also ensure that its contingency plans address, to the satisfaction of the Chief Safety Officer, the possibility of simultaneous occurrence of an accidental event on the Wellhead Platform in combination with adverse environmental conditions and that these contingency plans provide clear detail of the risk reduction measures that will be undertaken when such adverse environmental conditions are forecast and/or realized.

15. **The Proponent submit a plan, that is to the satisfaction of the Chief Safety Officer, to document and track the suite of safety studies required for detailed design. The plan is to include a schedule for satisfying the recommendations provided in the Proponent's Concept Safety Analysis. The Board, in consultation with the Chief Safety Officer, will establish the date by which submission must be made.**

16. **Prior to submission of any application for conducting activities under an authorization from the Board, the Proponent demonstrate, to the satisfaction of the Chief Safety Officer, that the recommendations from the Concept Safety Analysis have been addressed in a manner that brings risk to as low as reasonably practicable (ALARP).**

17. **The Proponent submit information to the Board that details the Quality Assurance Program and Quality Control Program that will be applied throughout all pre-operation phases of the project. The Board, in consultation with the Chief Safety Officer, will establish the date by which submissions must be made.**

18. **The Proponent submit, to the satisfaction of the Chief Safety Officer, the Scope of Work for the Certifying Authority. The Board, in consultation with the Chief Safety Officer, will establish the date by which submission must be made.**

Environment

Staff reviewed the proposed project to determine whether it raised any environmental concerns that were not previously assessed as part of the *White Rose Oilfield Comprehensive Study Report* completed in 2001, in the documents submitted by the Proponent in support of the new drill centres environmental assessment in the C-NLOPB's *New Drill Centre Construction and Operations Program CEA Act Screening* or in C-NLOPB Decisions 2001.01, 2007.02, 2008.03.

It was determined that the development of the White Rose Extension Project (WREP) using a WHP required a separate environmental assessment. The WREP includes the construction of the WHP onshore at Argentia and installation of the WHP in the White Rose Field. The C-NLOPB conducted a screening level environmental assessment that satisfied the requirements of both the Newfoundland and Labrador *Environmental Protection Act* and the federal *Canadian Environmental Assessment Act* (CEAA). The EA process that included a number of provincial and federal agencies, including Fisheries and Oceans Canada, Environment Canada, and Transport Canada as Responsible Authorities under the *Canadian Environmental Assessment Act* was completed in September 2013. The assessment concluded that, with the application of mitigation measures identified in the White Rose Extension Project Environmental Assessment and Addendum, the implementation of a follow-up program and adherence to relevant C-NLOPB guidance material, significant adverse environmental effects associated with the project were not likely.

From an environmental perspective, staff recommends to the Board that the application be approved subject to the following conditions:

1. **The Proponent will be required to submit to the Chief Conservation Officer, no later than 12 months prior to the scheduled commencement of offshore drilling activities associated with the Project, an amended Environmental Effects Monitoring (EEM) Plan design that incorporates drilling and production activities associated with the proposed activities, and tie-back to the *SeaRose FPSO*. The amended EEM Plan should be consistent with the strategy in the Husky EEM Design Report, discuss any changes that**

may be required to existing sampling stations, and consider the necessity for collection of baseline data at any or all of the new drill centre and CGS locations. Drilling operations associated with the Project will not be authorized until an acceptably amended EEM Plan is in place. Drill cutting dispersion model predictions will be validated in situ by monitoring the thickness of cutting piles on the seafloor once the White Rose EEM program is revised to accommodate operation of the WREP.

2. **The Proponent will be required, prior to commencement of offshore construction activities, to collect any field data required to inform the design of its EEM program.**

Operations

From the operations perspective, the analysis focused on well operations as well as the certification process for the wellhead platform. The Proponent affirmed the drilling, completion and well intervention activities for the WHP will be executed in accordance with established practices, policies and procedures. Staff will verify this in assessing any application for authorization of these activities.

The WHP meets the definition of “drilling installation” in the *Newfoundland Offshore Certificate of Fitness Regulations*. As a result, a certificate of fitness must be issued by a recognized certifying authority. The Proponent engaged the services of a certifying authority during the front-end engineering design.

In the meantime, the Proponent has commenced the process of identifying the codes and standards to be used for the design of the platform and to also seek clarification of the regulatory requirements by way of the regulatory query process.

From an operations perspective, staff recommends approval of the Application.

Recommendation

In conclusion, staff recommends that the Board approve the Application, subject to the conditions outlined in the resource management, safety and environment sections of this report.

3.0 BACKGROUND

3.1 The Application

On October 21, 2013 Husky Energy (Proponent) submitted to the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) on behalf of its co-venturers Suncor Energy and Nalcor Energy – Oil and Gas the following documents in support of the amendment to the existing White Rose Development Plan:

- White Rose Extension Project – White Rose Development Plan Amendment (October 2013)
- White Rose Extension Project – Socio-Economic Impact Statement and Sustainable Development Report (October 2013)
- White Rose Extension Project – Wellhead Platform Concept Safety Analysis (October 2013)
- White Rose Extension Project – White Rose Canada-Newfoundland and Labrador Benefits Plan Amendment (October 2013)

Staff reviewed these documents for completeness and based on its review requested additional information in a letter dated January 31, 2014. The Proponent responded by providing supplemental information in letters dated February 28, 2014 and March 19, 2014. After reviewing the Proponent's responses a second completeness letter dated April 24, 2014 was sent and additional information was provided by the Proponent in a letter dated June 5, 2014. Staff reviewed this response and determined that the documents were complete. The Proponent then resubmitted the following documents which are considered "the Application" and are the subject of this analysis:

- White Rose Extension Project – White Rose Development Plan Amendment (June 2014)
- White Rose Extension Project – Socio-Economic Impact Statement and Sustainable Development Report (June 2014)
- White Rose Extension Project – Wellhead Platform Concept Safety Analysis (June 2014)
- White Rose Extension Project – White Rose Newfoundland and Labrador Benefits Plan Amendment (June 2014)
- White Rose Extension Project –Development Application Summary (June 2014)

In considering the Application, the Board decided that a public review was necessary. So on June 12, 2014 the Board announced the Dr. Leslie Harris Centre of Memorial University perform the public review on behalf of the Board.

The outcomes of the public review are part of the Application and are considered in the staff's analysis and the Board's decision.

3.2 History/Context

The White Rose Field is located approximately 350 km east of St. John's, Newfoundland and Labrador, on the eastern edge of the Jeanne d'Arc Basin, in water depths ranging from 115 to 130 m. The White Rose Significant Discovery Area encompasses the White Rose Field, which was discovered in 1984 by drilling and testing of the Husky-Bow Valley et al. White Rose N-22 exploration well, and the adjacent North Amethyst Field, which was discovered in 2006 by the Husky Oil North Amethyst K-15 well. The two fields are known collectively as the White Rose Asset Area. Production has been ongoing since 2005 from White Rose Field and since 2010 from North Amethyst Field. The producing reservoir in both fields is the Ben Nevis - Avalon (BNA) Formation.

The White Rose Field includes four separate pools. Naming conventions for the pools have varied in the past: the Application uses the terms "North Avalon", "West White Rose" and "South White Rose Extension (SWRX)"; and the fourth pool is referred to interchangeably as "South White Rose" and "South Avalon". Board staff has adopted the following simplified nomenclature for the four pools throughout this document, and recommends its usage in future publications: North Pool, West Pool, South Pool and South Extension Pool (Figure 3.1). A single pool is recognized in the North Amethyst Field.

A note of clarification is required regarding the naming convention of the main reservoir within the White Rose Asset Area. The reservoir section was termed the “Avalon Formation” in the initial White Rose Development Plan Application (2001), and in the Board’s Decision 2001.01. However, current understanding indicates that the reservoir section lies upon the mid-Aptian unconformity, and is more likely to be the Ben Nevis Formation. The terms “Ben Nevis” and “Ben Nevis - Avalon” (BNA) are therefore used interchangeably throughout this analysis to refer to the reservoir interval.

The recoverable oil reserves within the BNA Formation at White Rose Field, expressed at a 50 percent probability level, are currently estimated by the C-NLOPB at 36.3 MMm^3 (229 MMbbls). The Board currently estimates, at a 50 percent probability level, that the BNA Formation at White Rose Field contains recoverable resources of 76.7 x 10^9 m^3 (2.7 TCF) of natural gas, and 13.8 MMm^3 (86 MMbbls) of natural gas liquids (NGLs). However, this Application does not propose exploitation of the gas and NGL resources at this time.

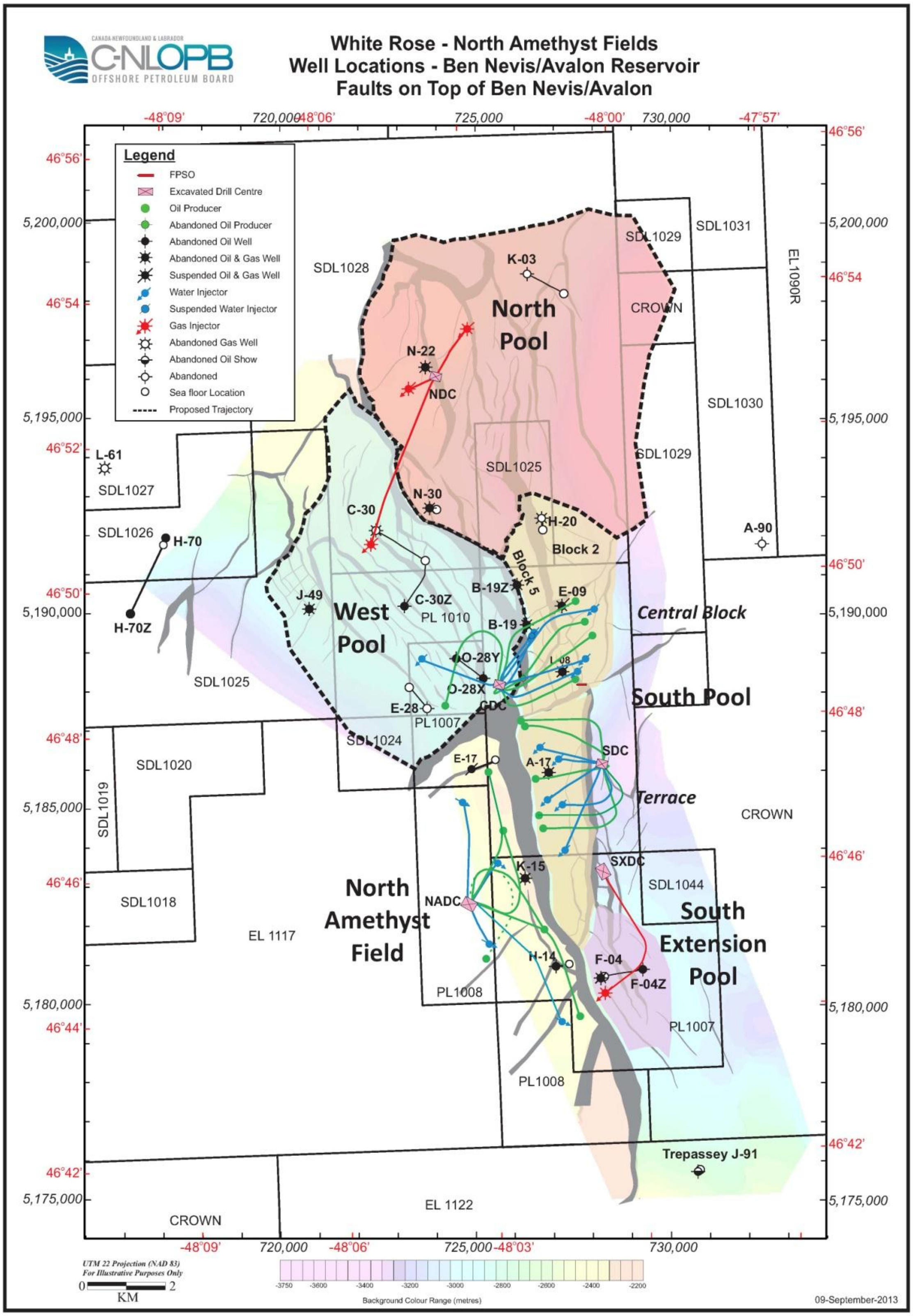

Figure 3.1: Map of the White Rose Asset Area, identifying well locations and pool boundaries.

At present, the White Rose Significant Discovery Area incorporates 14 Significant Discovery Licences (SDLs). There are also five Production Licences (PLs) located in the White Rose Significant Discovery Area, as indicated in Figure 3.2. PLs 1006 and 1007 are located in the White Rose Field. PLs 1009 and 1010 contain the West Pool and PL 1008 contains the North Amethyst Field.

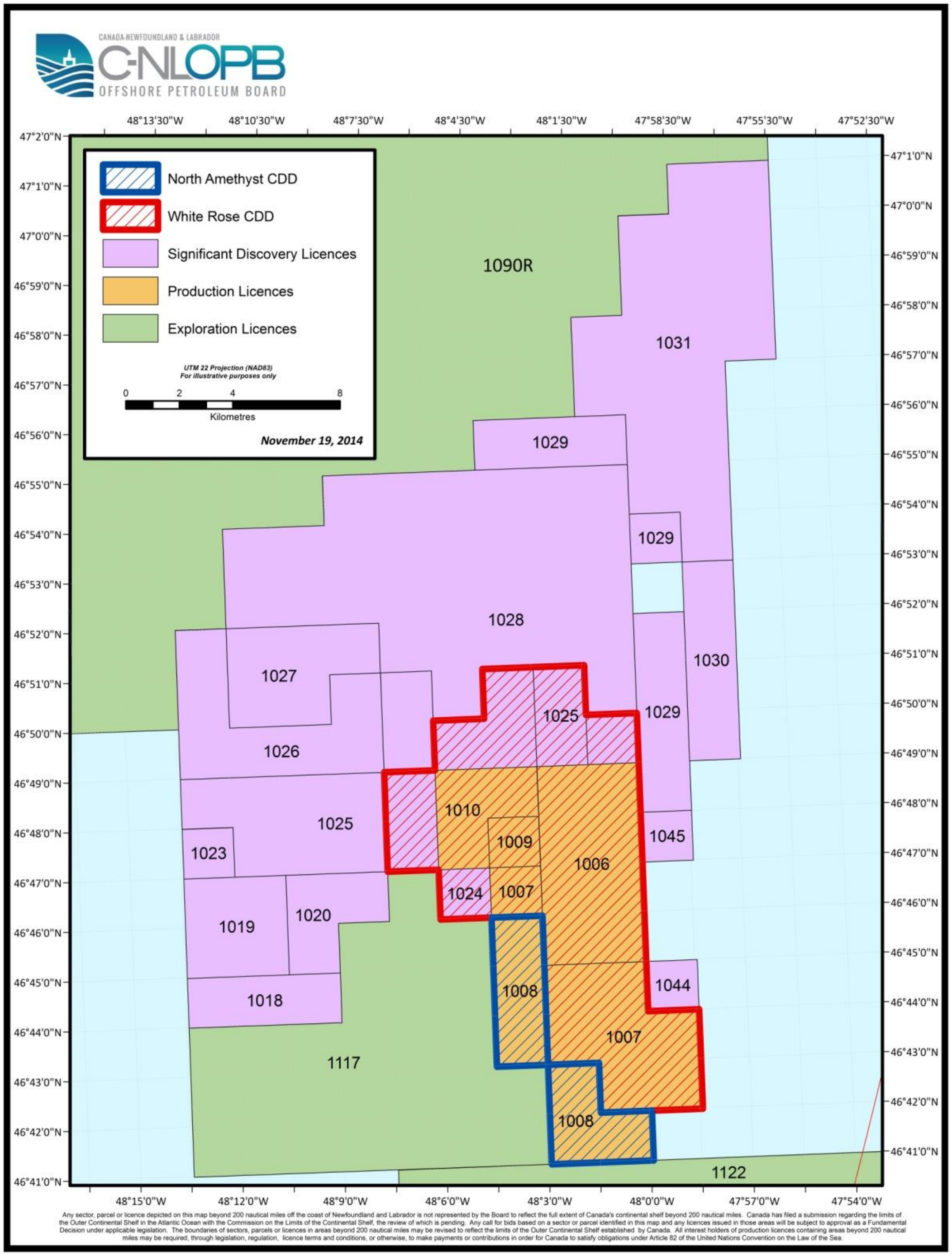

Figure 3.2: Map of the White Rose Significant Discovery Area, identifying Exploration Licences, Significant Discovery Licences and Production Licences.

Commercial oil production from the White Rose Field began on November 12, 2005. As of October 31st 2014, 19 development wells have been drilled and 29.9 MMm^3 (187.97 MMbbls) of oil have been produced from the White Rose South Pool. Production from the North Amethyst Field began on May 31, 2010. Ten development wells have been drilled in the North Amethyst Field and 6.1 MMm^3 (38.5 MMbbls) of oil have been produced to date. Two development wells were drilled for the West Pool pilot scheme (Decision 2010.01) with production commencing on September 5, 2011 and 1.32 MMm^3 (8.33 MMbbls) of oil produced to date. Four additional White Rose development wells were drilled as gas injectors, two in the North Pool, one in the West Pool and one in the Southern Extension Pool. Twenty-six exploration or delineation wells have been drilled in the region to date, including five within the West Pool. This drilling and production activity has provided a substantial quantity of information to assess reservoir and facility performance and to enable construction of geological and reservoir simulation models.

The Application proposes installation and operation of a wellhead platform (WHP) primarily to access the West Pool, but it will also enable production from the North Pool and the northernmost part of the South Pool. The WHP will consist of a concrete gravity structure (CGS) with topsides consisting of drilling facilities, wellheads and support services such as accommodations, utilities, a flare boom and a helideck. It will be tied back to the *SeaRose FPSO* to transport fluids for processing, storage and offloading. There will be no hydrocarbon storage on the WHP.

3.3 Public Review

The authority for having public reviews can be found in Section 44(1) of the Atlantic Accord Acts (Federal Version).

It states:

Public Review

44. (1) Subject to any directive issued under subsection 42(1), the Board shall conduct a public review in relation to any potential development of a pool or field unless the Board is of the opinion that the public hearing is not required on any ground the Board considers to be in the public interest.

The legislation indicates that a public review is to be conducted in relation to any potential development "unless the Board is of the opinion that the public hearing is not required on any ground the Board considers to be in the public interest". Therefore, the legislation contemplates that a public hearing may be necessary for some developments and not for others.

The Board's approach to this matter is described in its Development Plan Guidelines which indicates that the scale and scope of the public review should be commensurate with the scale of the development and the degree to which new and innovative techniques and approaches are proposed. In other words, the public review process is best determined on a case-by-case basis.

In consideration of the scale and scope of this project, staff was of the view that a public review was necessary and that the C-NLOPB should provide the public an opportunity to speak to issues beyond what can be offered through a website based pubic review only. The reasoning for this is as follows:

- the approach of using a concrete gravity structure to drill wells at the White Rose field is "new" to the Canada-Newfoundland and Labrador offshore area (although these structures are in use elsewhere and are considered to be proven technology);
- there are employment and other industrial benefits associated with the construction and operation of the platform that will likely attract significant public interest; and
- the socio-economic impacts associated with the construction of the concrete gravity structure may also garner significant public interest.

Based on this assessment staff recommended to the Board that a 90-day web-based public review process be conducted by an independent third party, supplemented by public information sessions. The Board agreed and on June 12, 2014 the C-NLOPB announced that Memorial University's Leslie Harris Centre of Regional Policy and Development ("the Harris Centre") would conduct a public review of the White Rose Development Plan Amendment (DPA) application – White Rose Extension Project (WREP).

The Harris Centre was tasked with the execution and completion of the public review within 90 days upon receipt of the Application, this would include public information sessions and the establishment and promotion of a website to solicit the public's input on the Application. The Harris Centre was also responsible for providing a report within 30 days following the completion of the public review, summarizing the issues and concerns brought forward by the public.

The public review began on June 12, 2014 and the public information sessions where held on June 24, 2014 in Placentia and June 25, 2014 in St. John's. The public review comment period ended on September 10, 2014 and the final public review report was submitted to the C-NLOPB on September 23, 2014.

There were six comments received via the website principally related to industrial benefits and SEIS matters. Of these two were written submissions by NOIA and Women's Advisory Council. The Proponent and the C-NLOPB responded to all matters. Board staff are satisfied with the Proponent's response.

A complete copy of the Harris Centre's report can be found in Appendix A.

It should be noted that all the comments and responses arising from the public review process were taken into account by the Board's staff in its analysis of the Application and its recommendations to the Board.

Finally, given that the majority of comments were benefits related staff have included responses to all public comments in Appendix B of the Benefits Plan staff analysis.

4.0 RESOURCE MANAGEMENT

4.1 Resource Management Review

Board staff reviewed the Application, including the Proponent's seismic interpretations, geological models and reservoir simulation models. Staff also conducted a review of reservoir, geological and production data acquired to November 2014 and used this data to construct geological and reservoir simulation models for the South, West and North pools. As of October 31, 2014, 29.9 MMm^3 (187.97 MMbbls) of oil have been produced from the South Pool and 1.32 MMm^3 (8.33 MMbbls) of oil have been produced by the West White Rose pilot scheme (Figures 4.1 and 4.2).

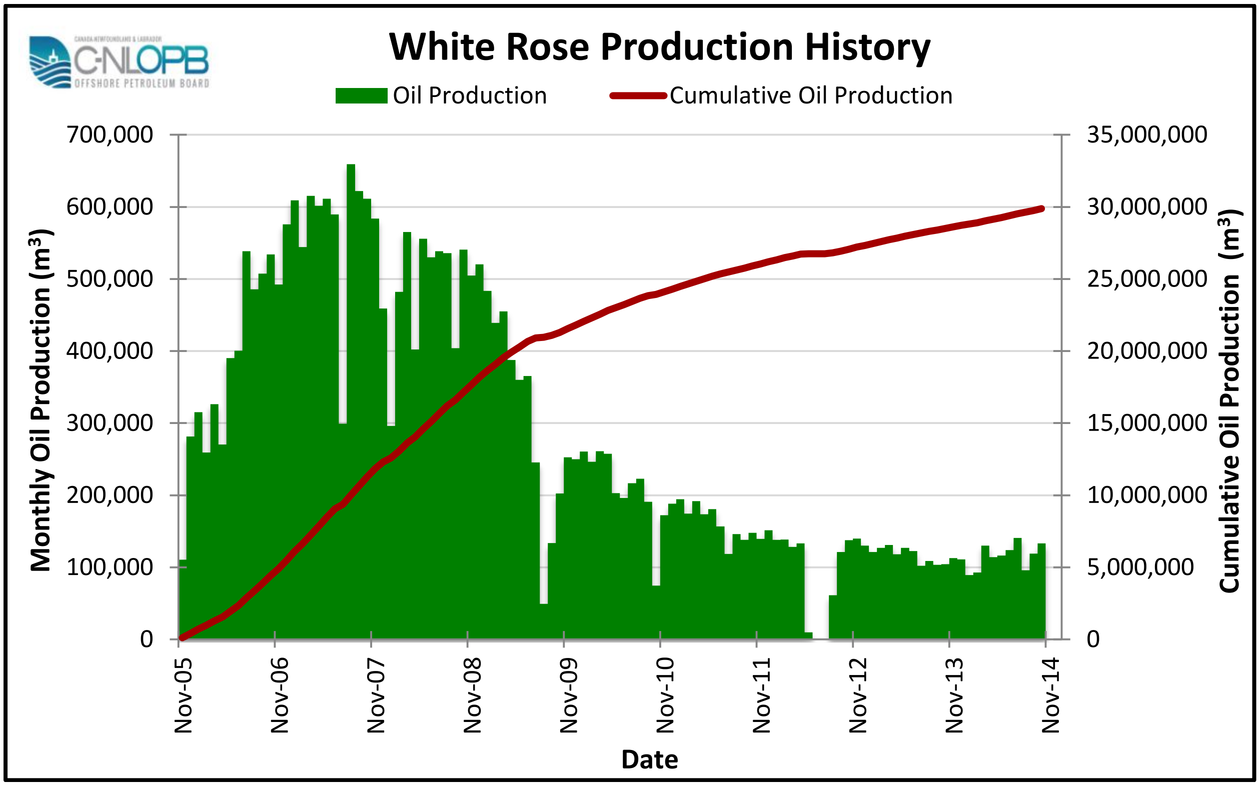

Figure 4.1: White Rose Field oil production. Volumes do not include production from the West White Rose Pilot Scheme.

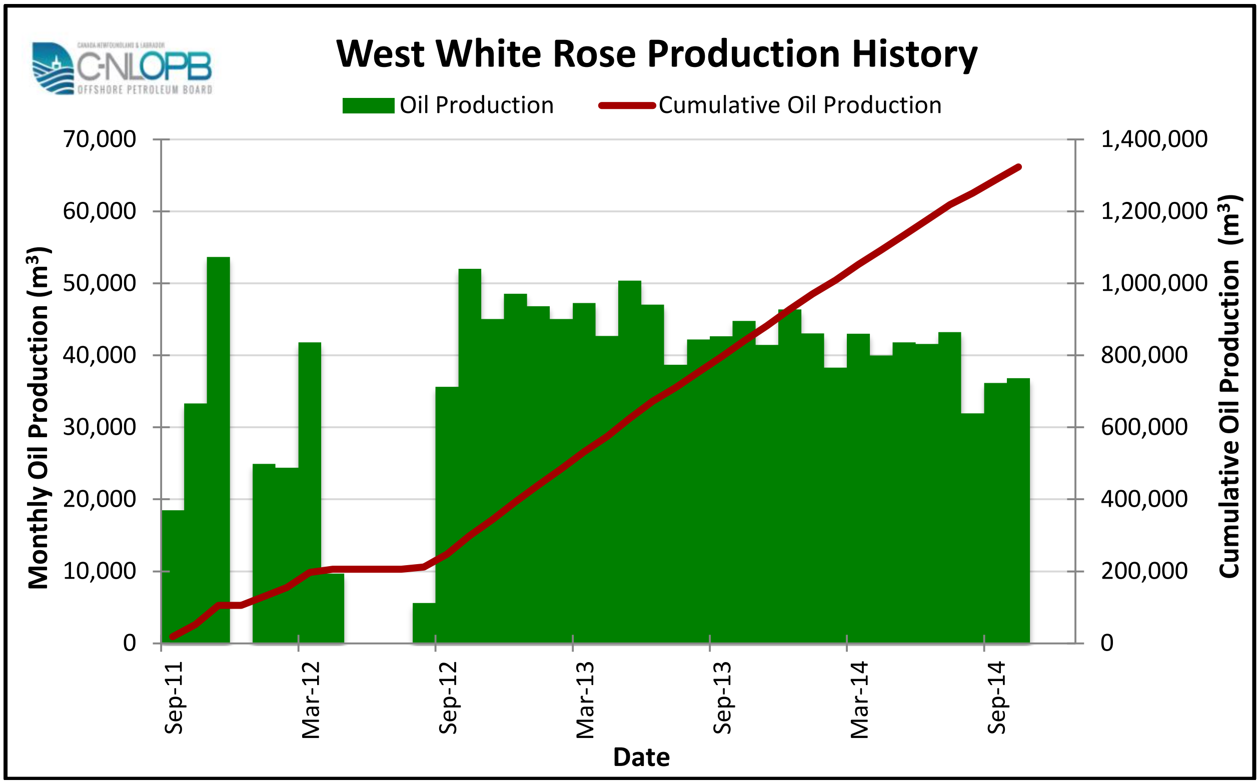

Figure 4.2: Oil production from West White Rose Pilot Scheme.

4.2 Geology, Geophysics and Petrophysics

4.2.1 Regional Geology

The Application provides a summary of the regional geology of White Rose Field. The Proponent extensively detailed the regional geologic history of the Jeanne d'Arc Basin in Decision 2001.01. In consideration of general industry understanding of the basin, that discussion adequately described the tectonic evolution of the White Rose region and a similar discussion is not required for this application.

4.2.2 Geology of White Rose

The White Rose Field is located within a highly faulted complex of rotated fault blocks. The field sits on the eastern margin of the Jeanne d'Arc Basin, bounded to the east by the Trave Fault, and is underlain by a basin-wide salt layer at depth. The northern and western extent of the White Rose structure is defined by basinward-dipping flanks of the structurally high field.

The principal reservoir at White Rose consists of shallow marine, fine-grained, quartzose sandstones of the Ben Nevis - Avalon (BNA) Formation. This Aptian to Albian-aged succession is interpreted to have been deposited along a southwest-northeast trending shoreface. The paleoshoreline was located to the east of field (Figure 4.3).

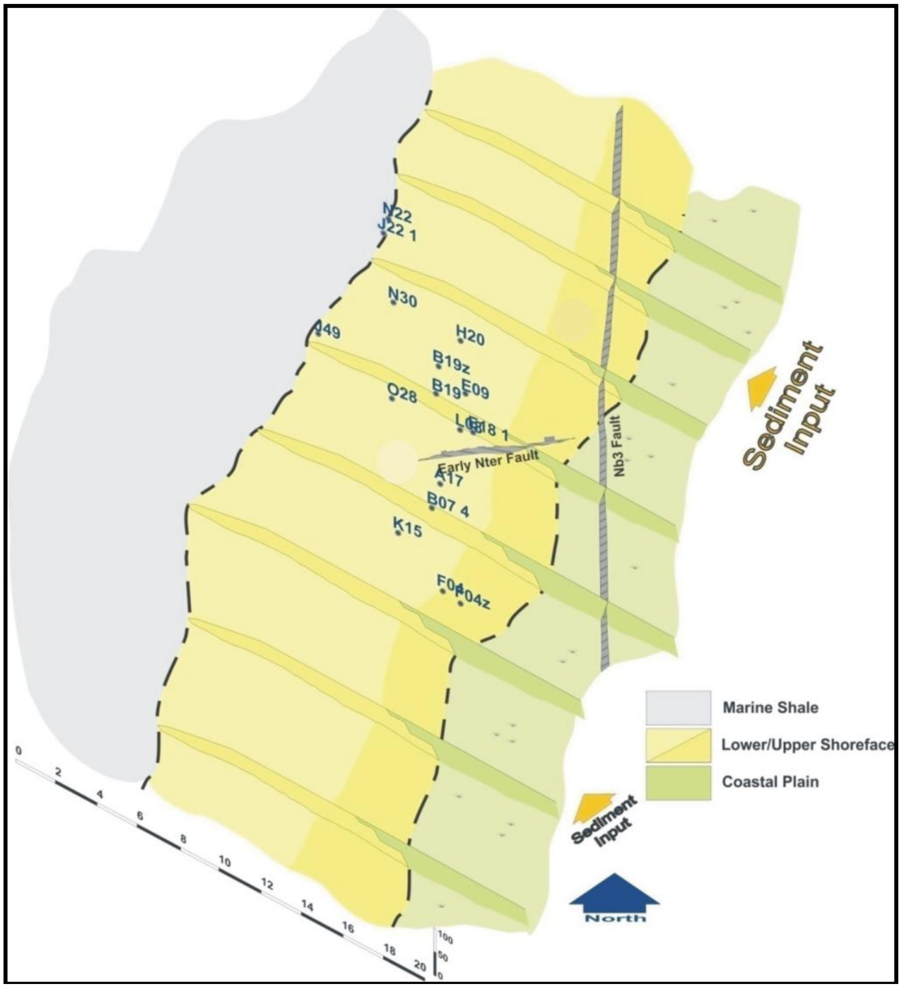

Figure 4.3: Schematic diagram showing aerial distribution of shoreface sandstones and early-moving faults related to the initial phases of Ben Nevis deposition. White Rose delineation wells are identified in relation to the paleogeography (From Husky, 2014).

4.2.3 Geology of WREP Project Area

4.2.3.1 Geology of the West Pool

The BNA Formation in the West Pool comprises some of the most distal reservoir facies in the field. Reservoir quality degrades from proximal facies in the east to more distal, finer-grained facies in the west. Reservoir quality and continuity are therefore lower than in other pools. Eleven parasequences have been identified, corresponding to coarsening upward cycles, within an overall fining/deepening upward retrogradational trend (Figure 4.4). Parasquences range in thickness from 6 to 25 m. These parasequences have been incorporated into the Proponent's geological models for the West Pool.

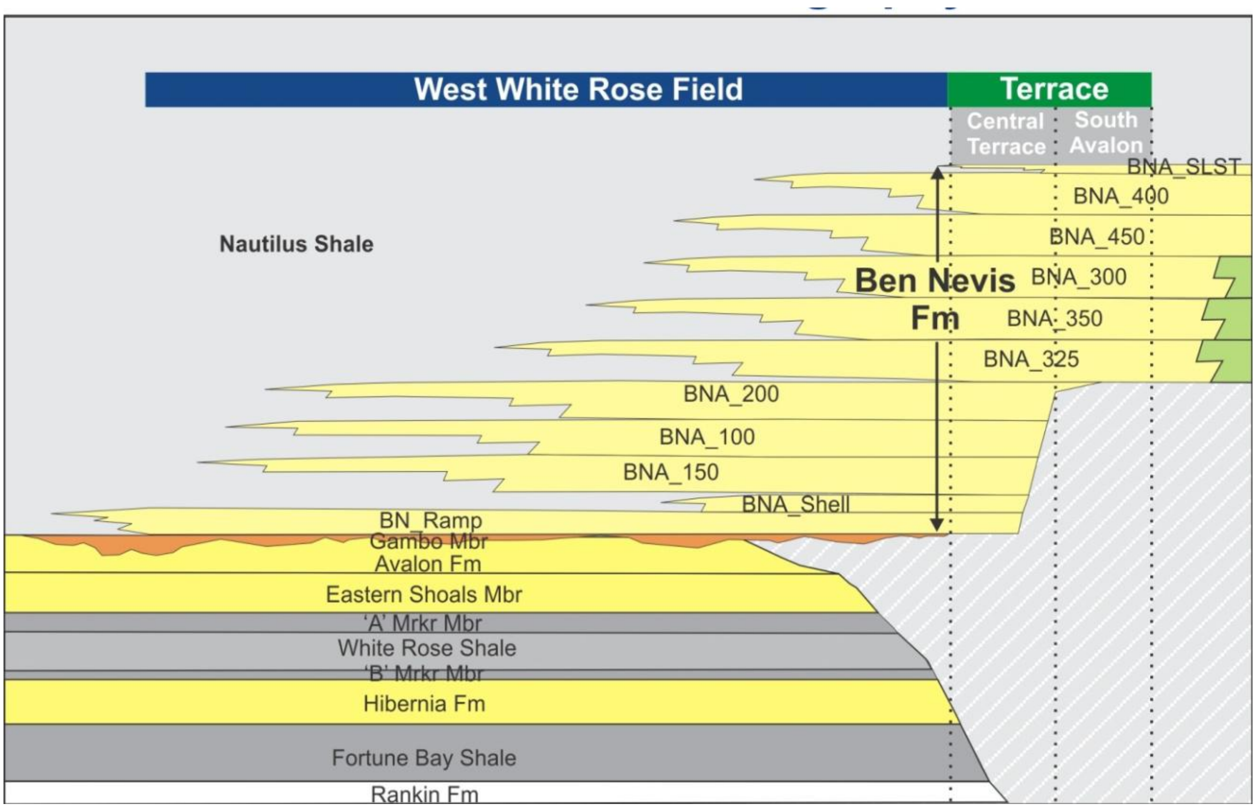

Figure 4.4: West Pool stratigraphy, showing internal divisions of the BNA Formation (From Husky, 2014).

The original White Rose Development Plan (2001) presented four main facies associations in the BNA. More recent work in support of the current application has identified an additional facies association, #2 in the list below.

1) Lower shoreface storm deposits, consisting of well sorted, very fine-grained sandstones with low-angle cross-stratified, laminated, massive and parallel laminated structures. These deposits form the main reservoir rock type in the region.

2) Bioturbated lower shoreface storm deposits, consisting of well sorted, very fine-grained sandstone with a bioturbated texture. Relict sedimentary structures are typically present but obscured.

3) Lower shoreface fair-weather deposits, consisting of heavily bioturbated siltstone to silty sandstone, with primary structures rarely preserved.

4) Marine deposits, consisting of laminated and structureless, variably silty shale with minor bioturbated intervals, representing the most distal component of deposition.

5) Diagenetic components, including secondary calcite cement nodules that are round and laterally discontinuous or lenticular and associated with shell lag intervals, and locally present siderite nodules.

4.2.3.2 Geology of South Pool

The South Pool (Figure 3.1) is part of the initial White Rose development. The currently undeveloped Blocks 2 and 5 comprise the northern extent of the pool. Depositional facies in South Pool are similar to those described above for West Pool; however, the geological setting of South Pool is more proximal, resulting in thicker, better quality reservoir. There are few vertical baffles/barriers to flow, and the oil column is approximately 130-140 m.

Blocks 2 and 5 comprise the undeveloped northern extent of the South Pool. Two delineation wells, H-20 and B-19Z, confirmed the presence of oil and gas in these fault blocks; however, the majority of reservoir quality sandstones in this area occur below the oil-water contact. Blocks 2 and 5 were included in the geological model for the North Pool submitted by the Proponent.

4.2.3.3 Geology of North Pool

The North Pool (Figure 3.1) currently serves as a storage location for produced gas. Facies associations in the North Pool are similar to those described for the West Pool: they represent distal depositional environments with low net reservoir. The reservoir tends to be compartmentalized due to thin reservoir intervals juxtaposed against non-reservoir rock across fault discontinuities.

4.2.4 Geophysics

Seismic data quality in the White Rose Asset Area is fair to good. The main seismic survey for the area was an Anisotropic Pre-Stack Depth Migration volume acquired in 2008; however, several gaps remain in this data from obstacles such as the FPSO, and areas that were not surveyed due to poor weather conditions. In such cases, older vintage seismic data were used to fill the gaps, and these were processed concurrently with the 2008 data. Board staff reviewed this seismic data and believes this approach to be appropriate.

The reservoir interval is imaged seismically as a low amplitude sequence indicative of a low impedance siltstone reservoir. The seismic interpretation is challenging given the low impedance contrast of the BNA reservoir and surrounding geology.

Three seismic horizons were interpreted over the WREP area: the BNEV_SLTST (top BNA) surface, the BNA_200 surface, and the Mid-Aptian Unconformity (base reservoir). The BNEV_SLTST is a difficult seismic pick in the WREP region because of the low impedance contrast with the overlying Nautilus Formation. Therefore, in some areas, particularly in the northern part of the West Pool and near the N-30 well, interpretation of this marker is guided by an isopached thickness from the BNA_200 to siltstone based on well log data. The BNA_200 internal surface is mapped confidently over the WREP area, and it provides improved constraint of the retrogradational parasequences. The Mid-Aptian Unconformity is a medium to high-amplitude horizon mapped with a high level of confidence over the area. The Proponent supplied geophysically controlled horizon and fault interpretations of the White Rose region. These interpretations were audited and verified by the Board’s geophysical staff.

4.2.5 Petrophysics

The petrophysics section of the Application focused on the West Pool. The Proponent conducted a comprehensive logging and coring program while drilling the six delineation wells (J-49, E-28, O-28Y, O-28X, C-30, C-30Z), one gas injection well (J-22 3), as well as the pilot producer/injector pair (E-18 10, E-18 11) in the West White Rose pilot scheme. The Application provides a summary of the Proponent’s petrophysical interpretation of the BNA reservoir for these wells. The Proponent supplied supplemental information on the methodology, assumptions and criteria used in their petrophysical analysis.

Staff reviewed the petrophysical data and determined that the Proponent’s petrophysical interpretation matches staff’s assessment with slight differences attributed to different methodology, assumptions and criteria used in interpreting the data. **Based on its analyses, Board staff believes the interpretation presented by the Proponent in support of the Application is reasonable and appropriate.**

4.2.6 Geological Reservoir Modelling

Board staff constructed two detailed 3D geological models using Petrel software to estimate in-place hydrocarbon resources. One model included the North Pool and Blocks 2 and 5 of the South Pool, and the second model covered the West Pool. The models incorporated available geophysical, geological and reservoir engineering data. Details of the modelling process used are included in Appendices B and C. The Board's geological models were used to calculate probabilistic estimates of in-place hydrocarbon volumes, reported in Section 4.3 below.

4.2.7 Geographic Extent

Examination of seismic surfaces and interpreted fluid contacts provided by the Proponent suggests that the hydrocarbon accumulation proposed for development by the WHP extends beyond the boundaries of the existing White Rose Commercial Discovery Area. Both the West Pool and the North Pool likely extend onto areas currently subject to Significant Discovery Declarations. Therefore, the Proponent will be required not only to apply for an amendment to extend the White Rose Commercial Discovery Area, but also must be issued a production licence prior to production commencing for these pools. **No production from the wellhead platform can occur from that portion of the White Rose Commercial Discovery Area without a production licence(s).**

4.3 Oil and Gas in Place

Board staff conducted an assessment of the in-place hydrocarbon resources in the West, North, and South pools. The deterministic hierarchical geological models created in Petrel were used as a basis for the BNA stochastic assessment. Multiple parameters were varied in the assessment, including facies, porosity, water saturation, hydrocarbon contacts and shrinkage (Appendices A and B).

A comparison of the Proponent's and the Board's volumetric estimates for oil proposed to be exploited from the WREP are shown in Table 4.1.

Table 4.1: Comparison of Proponent and C-NLOPB estimates of stock-tank original oil in place. Values are reported for the BNA reservoir within West Pool, North Pool, Blocks 2 and 5, and remainder of South Pool.

Pool	Units	Downside		Best Estimate		Upside	
		Husky	C-NLOPB	Husky	C-NLOPB	Husky	C-NLOPB
West	MMbbls	317.6	742	458.5	836	591.2	949
	MMm^3	50.5	118	72.9	133	94.0	151
North	MMbbls	30.2	84.9	39.0	103	50.3	125.2
	MMm^3	4.8	13.5	6.2	16.4	8.0	19.9
Blocks 2&5	MMbbls	27.7	41.5	45.4	49.6	47.2	56.6
	MMm^3	4.4	6.6	7.22	7.9	7.5	9.0
South	MMbbls	460.4	620	544.1	647	640.3	678
	MMm^3	73.2	99	86.5	103	101.8	108

West Pool
Overall, there is a discrepancy between the Proponent and the Board's volumetric assessment for STOOIP in the West Pool. Differences between the Proponent and Board STOOIP estimates are attributed to variations in geological and reservoir modelling approaches, petrophysical analyses and parameters varied in the uncertainty analysis. Board staff believes that the Proponent's modelling approach and resulting STOOIP volumes are conservative, especially considering better than expected production that has been achieved by the pilot scheme. Future drilling and production data will allow better understanding of reservoir quality and hydrocarbon volumes and refinement of the models as development progresses.

North Pool
There is also significant discrepancy between the Proponent's and the Board's volumetric assessment for STOOIP in the North Pool. Well data is very sparse within the North Pool, which increases the uncertainly of geological interpretation. Differences between the Proponent and Board STOOIP estimates are attributed to variations in geological and reservoir modelling approaches, petrophysical analyses and parameters varied in the uncertainty analysis. It is notable that the Proponent's STOOIP estimate for the North Pool has decreased significantly since submission of the DPA for the West Pool pilot scheme (2009). The 17.9 MMm^3 volume reported at that time is close to the Board's current estimate.

Blocks 2 and 5
There is relatively good agreement between the Proponent's and staff's STOOIP estimates for Blocks 2 and 5. Differences can be attributed to differences in modelling approach, petrophysical analyses, and interpretation of fluid contacts.

Estimates for OGIP were provided in the Application for the West Pool, North Pool, and Blocks 2 and 5 (Table 4.2).

Table 4.2: Proponent's estimates of gas in place in the BNA reservoir within West Pool, North Pool, Blocks 2 and 5, and remainder of South Pool.

	Pool	Units	Downside	Best Estimate	Upside
Gas Cap OGIP	West	GCF	362.0	514.7	699.2
		Gm^3	10.2	14.5	19.7
	North	GCF	252.0	337.2	447.2
		Gm^3	7.1	9.5	12.6
	Blocks 2&5	GCF	17.7	21.3	35.5
		Gm^3	0.5	0.6	1.0
	South (remainder)	GCF	351.4	450.8	578.5
		Gm^3	9.9	12.7	16.3
Solution Gas OGIP	West	GCF	216.5	308.8	404.6
		Gm^3	6.1	8.7	11.4
	North	GCF	21.3	28.4	35.5
		Gm^3	0.6	0.8	1.0
	Blocks 2&5	GCF	21.3	28.4	31.9
		Gm^3	0.6	0.8	0.9
	South (remainder)	GCF	326.5	394.0	472.1
		Gm^3	9.2	11.1	13.3

Board staff conducted a preliminary review of gas resources for the WREP. Sparseness of data in the North Pool and Blocks 2 and 5, makes interpretation and modelling difficult. In particular, there is a high degree of uncertainty about the aerial extent of gas-filled reservoir, and therefore a wide range of possible OGIP volume.

Staff's assessment of gas resources in the West Pool is detailed in Appendix B. Staff believes that the Proponent's OGIP estimate for the West Pool is reasonable, and the model accurately reflects the available data.

4.4 Reservoir Engineering

Analysis of the reservoir engineering component of the Application included a review of the following items for the pools proposed to be developed from the WREP:

- Reservoir pressures
- Reservoir temperatures
- Fluid characterization
- Special core analysis

Vertical interference testing and drill stem test results from the West Pool were also reviewed.

4.4.1 West Pool

4.4.1.1 West Pool Reservoir Pressures

Six delineation wells and three development wells have been drilled in the West Pool to date.

Reservoir pressures were obtained from hydrocarbon contacts and gradients encountered in a number of the wells in the area. A pressure-versus-depth plot for the area is illustrated in Figure 4.5.

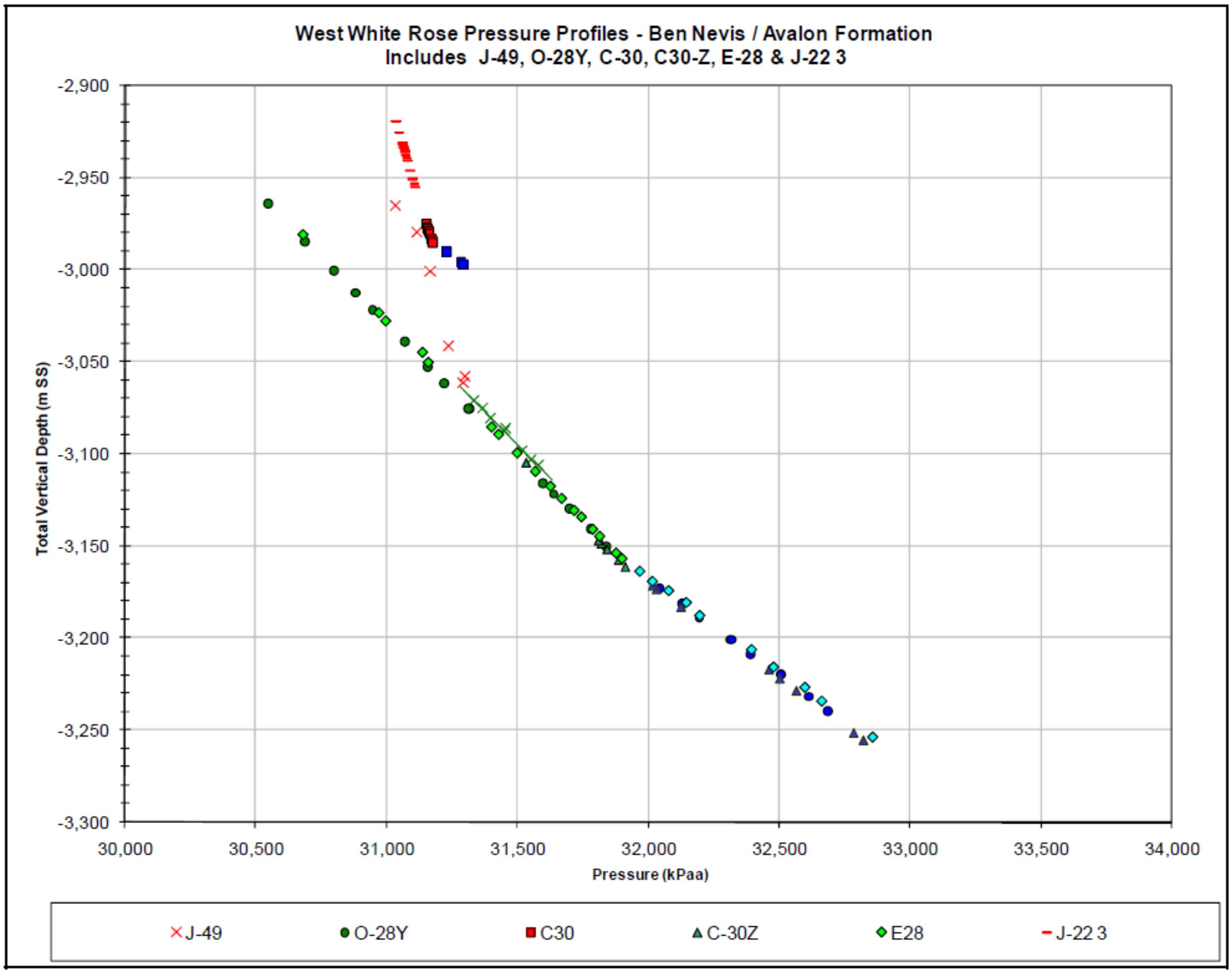

Figure 4.5: West Pool pressure versus depth (From Husky, 2014).

The fluid gradients for the West Pool were determined through modular dynamic formation tester (MDT) data and are listed in Table 4.3. The fluid gradients for gas, oil and water are similar to those encountered in other areas of White Rose Field.

Table 4.3: Proponent's fluid gradients for each of the wells in the West Pool (From Husky, 2014).

Well	Reservoir Gas Gradient (kPa/m)	Reservoir Oil Gradient (kPa/m)	Reservoir Water Gradient (kPa/m)
E-18 10	N/A	6.83	N/A
E-18 11	N/A	N/A	N/A
E-28	N/A	7.24	9.82
O-28 Y	N/A	6.90	9.70
C-30	2.50	N/A	N/A
C-30Z	N/A	6.74	9.66
J-49	1.78	6.85	N/A
J-22 3	2.11	N/A	N/A

The Proponent's interpreted fluid contacts for each of the wells in the West Pool are listed in Table 4.4.

Table 4.4: Proponent's West Pool fluid contacts.

Well	Contact	Subsea Depth (m TVDss)
E-18 10	All oil, no fluid contact encountered	
E-18 11	Oil/water	3,170.1
E-28	Oil/water	3,173.5
O-28 Y	Oil/water	3,167.1
C-30	All gas, no fluid contact encountered	
C-30Z	Oil/water	3,172.8
J-49	Gas/oil	3,068.8
J-22 3	Gas injector, no fluid contact encountered	

Based on analysis of the pressure data, the Proponent has selected to use an oil-water contact (OWC) of 3170 m TVDss in its models. A gas-oil contact (GOC) of 3069 m TVDss was selected for the J-49 well region and a GOC of 3085 m TVDss was selected for the C-30 region.

Staff's analysis used the data gathered from log interpretation along with the pressure data acquired through several Modular Dynamic Tester (MDT) evaluations on wells in the West Pool. Based on its independent analysis, staff selected an OWC of 3155 m TVDss. A GOC of 3069m TVDss was selected based on the J-49 well results and used by Board staff throughout the West Pool model.

Although staff has determined slightly different values for the fluid contacts and gradients, it agrees that the methodology used by the Proponent is reasonable and justified. The slight differences in values can be attributed to different methodology, assumptions and criteria used in interpreting the data.

4.4.1.2 West Pool Reservoir Temperatures

Early estimates of reservoir temperature in the West Pool were made based on logging tools from delineation wells in the area. The expected temperature range from these early estimates was from 110°C to 117°C.

The most accurate reservoir temperature data available at this time are from the start-up of the West Pool pilot producer E-18 10, and water injector E-18 11. The downhole temperatures range from 108°C to 115°C, corresponding closely to the estimated temperatures from the delineation wells. The Proponent used a reservoir temperature of 106°C in the WREP reservoir simulation model.

Board staff considers the Proponent's analysis and use of the temperature data to be reasonable and appropriate for the West Pool.

4.4.1.3 West Pool Fluid Characterization

The Proponent collected fluid samples from the O-28Y, C-30, C-30Z, E-28 and J-22 3 wells and conducted detailed analysis of the gas, oil and water samples. The pressure-volume-temperature (PVT) analysis conducted on an O-28Y oil sample was selected as the representative oil sample for the West Pool. This fluid analysis indicated a GOR of 105.5 m^3/m^3, a saturation pressure of 26,290 kPa and an initial oil formation volume factor of 1.29 m^3/m^3.

Board staff considers the Proponent's oil, gas and water characterizations to be reasonable and appropriate.

4.4.1.4 West Pool Special Core Analysis (SCAL)

The oil-water and gas-oil relative permeability curves used in the West Pool model are based on relative permeability testing that was conducted using stacked plug core samples obtained from O-28Y, C-30Z and E-28 wells. The relative permeability endpoints for each of the five rock types (laminated sandstone, bioturbated sandstone, bioturbated siltstone, calcite and shale) are presented in the Application.

Board staff considers the Proponent's approach to incorporating SCAL data to be acceptable.

4.4.1.5 West Pool Vertical Interference Testing

Vertical interference testing was completed on O-28Y, E-28 and E-18 11 in the West Pool. All detailed vertical interference testing results and interpretation reports have been submitted to the C-NLOPB. E-28 interference testing assessed the permeability of the reservoir, and E-18 11 interference testing assessed the vertical communication and permeability in the various parasequences of the formation.

Staff reviewed the interference testing results and found them to be reasonable. Each test was reviewed and compared with testing results presented in the Application.

4.4.1.6 C-30Z Drill Stem Test Results

The Proponent conducted two separate drill stem tests (DSTs) at the C-30Z well over the upper and lower BNA reservoir intervals. The lower interval was tested at rates of 1200 bbls/d during the main flowing period, and the second interval did not flow to surface. Details on the upper and lower interval can be seen in Figures 4.6 and 4.7.

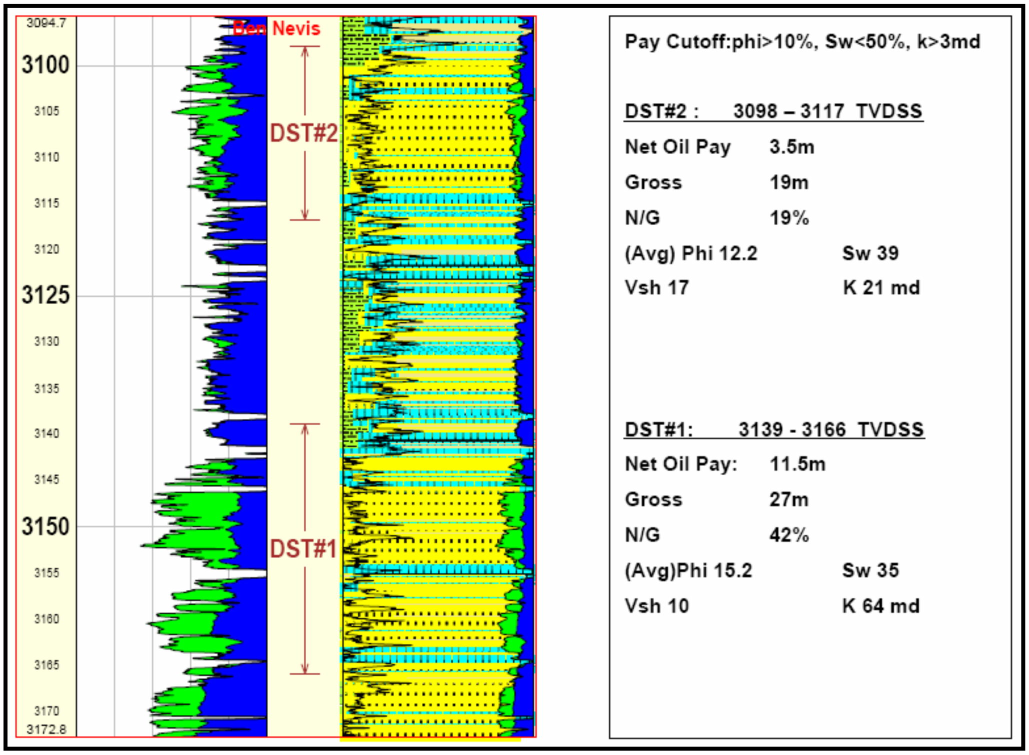

Figure 4.6: C-30Z DST intervals (From Husky, 2014).

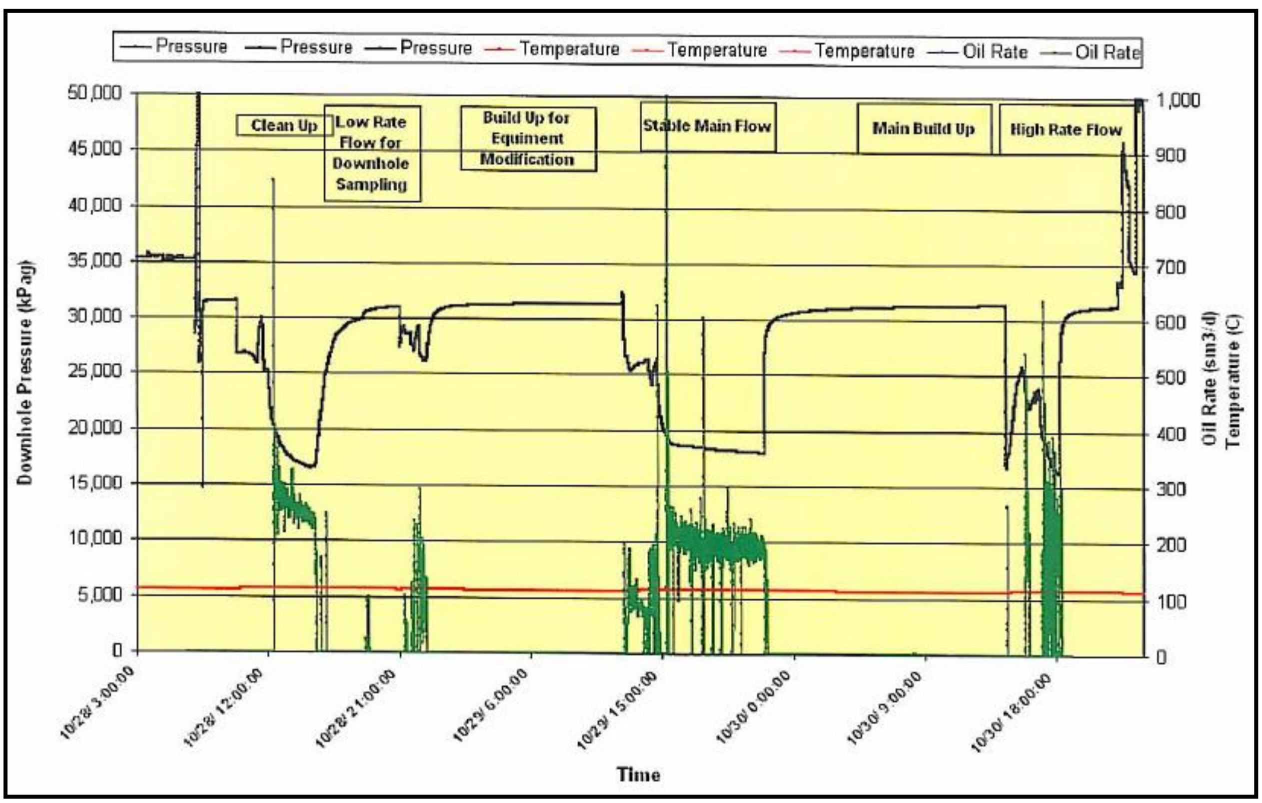

Figure 4.7: C-30Z DST #1 flow and build-ups (From Husky, 2014).

Staff reviewed the DST results and the Proponent's interpretations of the DST pressure build-ups, and found them to be reasonable.

4.4.2 North Pool

4.4.2.1 North Pool Reservoir Pressures

Two delineation, one exploration and two development wells have been drilled in the North Pool to date.

Reservoir pressures were defined by hydrocarbon contacts and gradients obtained in four wells within the region. A pressure-versus-depth plot for the area is illustrated in Figure 4.8.

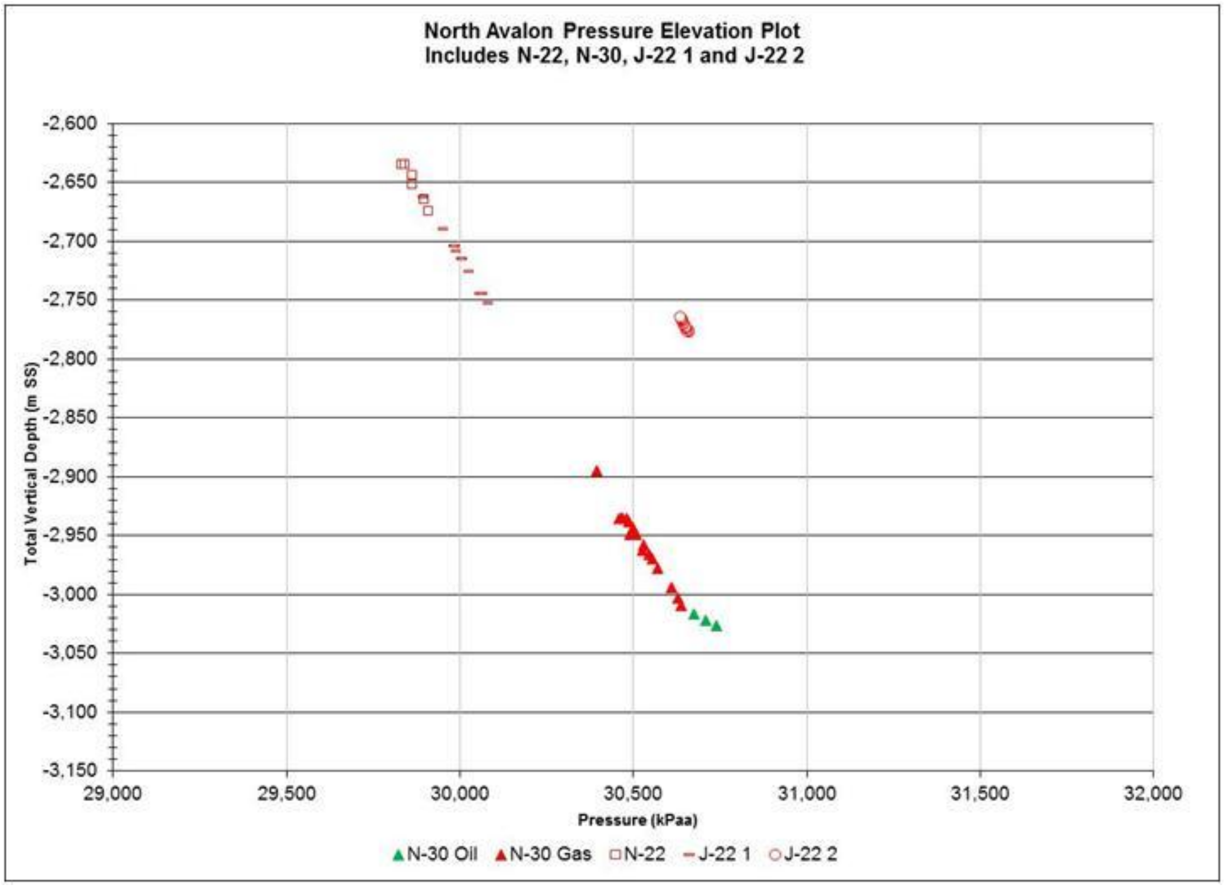

Figure 4.8: North Pool pressure versus depth (From Husky, 2014).

The fluid gradients for the North Pool were determined through MDT data and are listed in Table 4.5. The fluid gradients for gas, oil and water are similar to those encountered in the other areas of the White Rose Field.

Table 4.5: Proponent's fluid gradients for each well in the North Pool.

Well	Reservoir Gas Gradient (kPa/m)	Reservoir Oil Gradient (kPa/m)	Reservoir Water Gradient (kPa/m)
N-22	1.99	N/A	N/A
N-30	2.26	6.7	N/A
J-22 1	2.05	N/A	N/A
J-22 2	1.85	N/A	N/A

The Proponent's interpreted fluid contacts for each of the wells in the North Pool are listed in Table 4.6.

Table 4.6: Proponent's interpreted fluid contacts for each well in the North Pool.

Well	Contact	Subsea Depth (m TVDss)
N-22	Gas, no fluid contact encountered	N/A
N-30	Gas/oil	3,014
J-22 1	Gas injector, no fluid contact encountered	N/A
J-22 2	Gas injector, no fluid contact encountered	N/A
K-03	Water, no fluid contact encountered	N/A

The Proponent has selected a GOC of 3014 m TVDss base on results from the N-30 well. An OWC of 3084 m TVDss has been assumed by the Proponent based on the extrapolation of MDT pressure data acquired from the N-30 well to regional water gradients within the White Rose Field. These are consistent with the fluid contacts used in the Proponent's North Pool reservoir simulation.

Staff's analysis agreed with the Proponent's selected GOC of 3014 m TVDss, based on independent analysis of data from the N-30 well. As no fluid contact in the North Pool has been encountered to determine an OWC directly, the staff agrees with the Proponent's approach of using regional fluid gradients to estimate the OWC at 3084 m TVDss. This value is based on the assumption that there is pressure communication and similar fluid gradients between the North Pool and surrounding areas.

The methodology used by the Proponent is reasonable and justified based on the amount of information available at this time. The assumptions used to determine the OWC in the North Pool should be re-evaluated and verified when more data is obtained from future wells.

4.4.2.2 North Pool Reservoir Temperatures

North Pool reservoir temperature data have been estimated from two primary sources: downhole temperatures from current gas injectors J-22 1 and J-22 2, as well as temperature data from the West Pool.

The anticipated temperature in the North Pool ranges from 108°C to 115°C. The Proponent used a reservoir temperature of 106^{o}C in the North Pool reservoir simulation model.

Board staff considers the Proponent's analysis and use of the temperature data to be reasonable and appropriate for the North Pool region.

4.4.2.3 North Pool Fluid Characterization

The Proponent collected fluid samples from the N-30, J-22 1 and J-22 2 wells and conducted detailed analysis of the gas and oil samples. Based on the differential liberation experiment, the blended fluid sample has a saturation pressure of 30,751 kPa at 106°C, a GOR of 120.1 m^3/m^3 and an initial oil formation volume factor of 1.313 m^3/m^3.

Board staff considers the Proponent's oil and gas characterizations of the North Pool to be reasonable and appropriate.

4.4.2.4 North Pool Special Core Analysis

SCAL was conducted on core obtained from the N-30 well; however, the resulting relative permeabilities were deemed to be not representative. For this reason, relative permeability functions for the five facies types within the North Pool were based upon the South Pool model, and were subsequently adjusted to accommodate the estimated irreducible water saturations. The relative permeability endpoints for each of the five rock types (laminated sandstone, bioturbated sandstone, bioturbated siltstone, calcite and shale) are presented in the Application.

Board staff considers the Proponent's approach to incorporating SCAL data to be acceptable.

4.4.3 South Pool (Including Blocks 2 and 5)

4.4.3.1 South Pool Reservoir Pressures

Six delineation and 19 development wells have been drilled in the South Pool (including Blocks 2 and 5) to date.

Reservoir pressures were defined by hydrocarbon contacts and gradients encountered in several exploration, delineation and development wells within the region. A pressure-versus-depth plot for the area is illustrated in Figure 4.9.

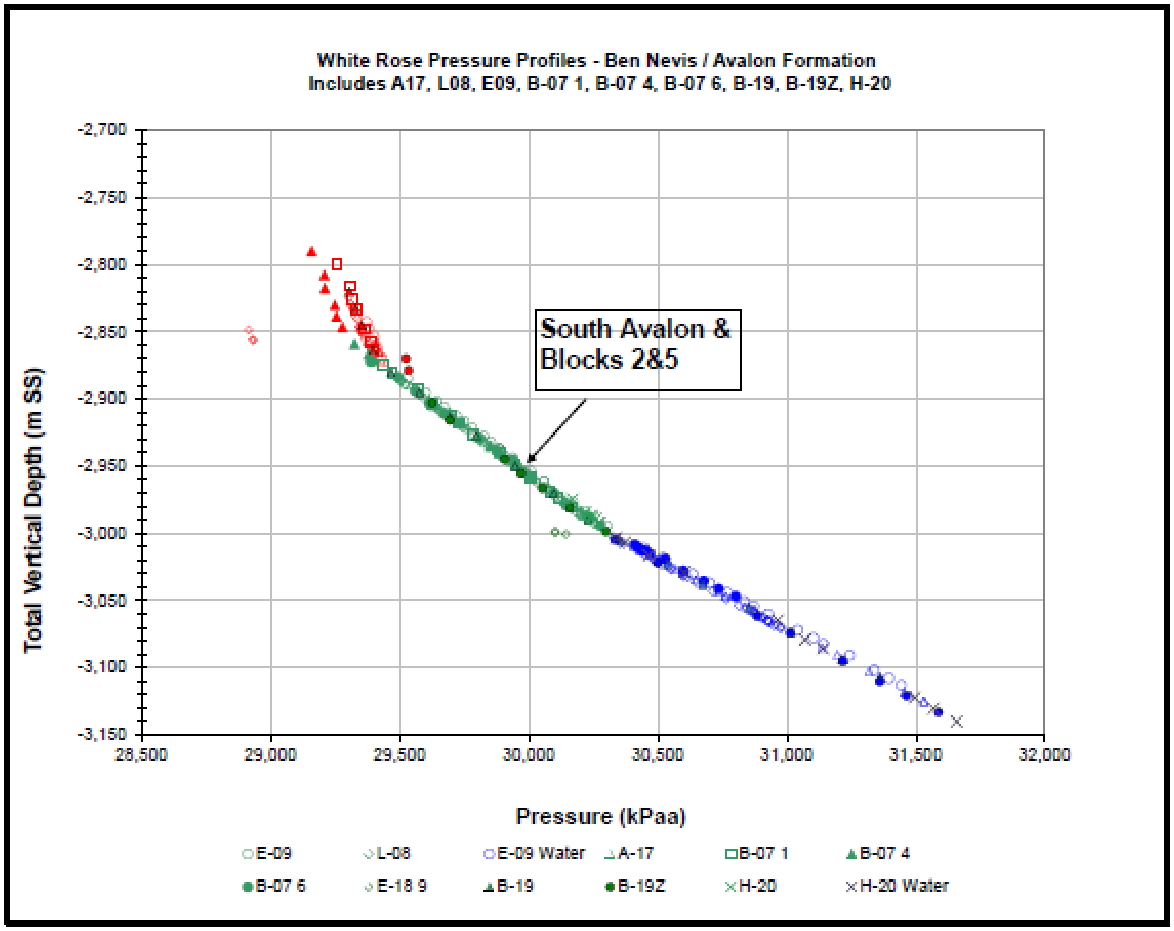

Figure 4.9: South Pool (including Blocks 2 and 5) pressure versus depth (From Husky, 2014).

The fluid gradients for the South Pool (including Blocks 2 and 5) were determined through MDT data, and are listed in Table 4.7. The fluid gradients for gas, oil and water are similar to those encountered in other areas of the White Rose Field.

Table 4.7: Proponent's fluid gradients for South Pool, including Blocks 2 and 5.

Well	Reservoir Gas Gradient (kPa/m)	Reservoir Oil Gradient (kPa/m)	Reservoir Water Gradient (kPa/m)
A-17	1.71	6.96	9.71
L-08	2.11	6.98	9.69
E-09	2.28	7.09	9.81
H-20	N/A	6.15	9.67
B-07 1	2.13	6.84	N/A
B-07 4	2.06	6.92	N/A
B-07 6	N/A	7.18	10.22
B-19Z	1.11	7.06	9.74

The fluid contacts encountered in the South Pool wells are shown in Table 4.8.

Table 4.8: Proponent's fluid contacts for South Pool, including Blocks 2 and 5.

Well	Contact	Subsea Depth (m SS TVD)
A-17	Gas/oil	2,874.4
L-08	Gas/oil	2,872.0
E-09	Gas/oil	2,869.4
H-20 (Block 2)	Oil/water	3,003.2
B-07 1	Gas/oil	2,871.5
B-07 4	Gas/oil	2,858.9
B-07 6	Oil/water	2,998.5
B-07 11	Gas/oil	2,869.2
E-18 9	Gas/oil	2,873.8
	Oil/water	3,003.7
B-19Z (Block 5)	Gas/oil	2,893.6
	Oil/water	3,004.8

Within the Terrace region of the South Pool, an oil-water contact of 2999 m TVDss has been assumed. A gas-oil contact of 2872 m TVDss has been assumed in the northern part of the Terrace, and a gas-oil contact of 2859 m TVDss has been assumed in the southern part of the Terrace. In the Central Drill Centre (CDC) region of the South Pool oil-water and gas-oil contacts of 3009 m TVDss and 2872 m TVDss, respectively, have been assumed. In Block 2, oil-water and gas-oil contacts of 3005 m TVDss and 2872 m TVDss, respectively, have been assumed. In Block 5, oil-water and gas-oil contacts of 3003 m TVDss and 2893 m TVDss, respectively, have been assumed. These contacts are consistent with the fluid contacts used in the Proponent's South Pool reservoir simulation.

Based on petrophysical analysis, Board staff interpreted a higher GOC in Block 5. The Board's model applied a GOC of 2871.5 m TVDss. This difference likely accounts for some of the discrepancy between the Board's and the Proponent's in-place volumes for Block 5.

Board staff considers the Proponent's analysis and use of the pressure data and contacts to be reasonable and appropriate for the South Pool region.

4.4.3.2 South Pool Reservoir Temperatures

The temperature gradient in the South Pool is well understood due to the number of development wells that have been drilled there. The maximum initial temperature of 108°C was observed in the South Pool, which was measured at the E-18 7 water injection well. The maximum initial temperature observed within the Terrace region of the South Pool was 105°C, measured at the B-07 8 water injection well. As a result, the estimated reservoir temperature for the South Pool, including Blocks 2 and 5, is 106°C, which was used in the Proponent's South Pool reservoir simulation model.

Board staff considers the Proponent's analysis and use of the temperature data to be reasonable and appropriate for the South Pool region.

4.4.3.3 South Pool Fluid Characterization

The Proponent collected fluid samples from several wells in the South Pool and conducted detailed analysis of the gas and oil samples. The most representative PVT dataset for South Pool, including Blocks 2 and 5, has a GOR of 128.5 m^3/m^3, a saturation pressure of 29,100 kPa and an initial formation volume factor of 1.359 m^3/m^3.

Board staff considers the Proponent's oil and gas characterizations of the South Pool to be reasonable and appropriate.

4.4.3.4 South Pool Special Core Analysis

Oil-water and gas-oil relative permeability curves for the South Pool were derived from core flood tests from the White Rose L-08 well. The SCAL work conducted for the South Pool is also considered representative of Blocks 2 and 5. The relative permeability endpoints for each of the five rock types (laminated sandstone, bioturbated sandstone, bioturbated siltstone, calcite and shale) are presented in the Application.

Board staff considers the Proponent's approach to incorporating SCAL data to be acceptable.

Overall, staff believes that the Proponent has provided sufficient information about reservoir engineering for the project area. The approach to reservoir characterization is appropriate and reasonable.

4.5 Reservoir Exploitation

The Application proposes development of the West Pool, North Pool and Blocks 2 and 5 of the South Pool from the WHP (Table 4.9). As the West Pool has the largest reserves of all these pools, it will be the primary focus of the WREP. Infill development well drilling in the currently producing Terrace and Central Blocks of the South Pool is also proposed from the WHP.

Table 4.9: Proposed WREP well count, as described in the Application.

Pool	Well Count
West Pool	26
Blocks 2 and 5	3
North Pool	2
South Pool	5
Drill Cuttings Injection	2
Total	**38**

4.5.1 West Pool

4.5.1.1 History

The West Pool is located in the northwestern part of the field (Figure 3.1). The West Pool was identified as a potential area for future development in the White Rose Development Plan (2001). At that time, only the J-49 delineation well had been drilled into the West Pool. The Proponent noted in the original Development Plan that additional information and assessment were required to determine the feasibility of the pool for development. The Board agreed with the Proponent in Decision 2001.01 that additional information was required prior to proceeding with development of the pool.

To further evaluate the development feasibility of the West Pool, the Proponent conducted additional delineation drilling. Since Decision 2001.01, five additional delineation wells (O-28Y, O-28X, C-30, C-30Z and E-28) have been drilled in the West Pool. The additional data acquired led to better understanding of the pool, but a significant level of uncertainty around development potential of the West Pool still remained due the reservoir being highly stratified and faulted.

In order to reduce uncertainty about the development feasibility of the West Pool, the Proponent submitted the "White Rose Development Plan Amendment, West White Rose – Pilot Scheme" to the Board in 2009 to receive approval to conduct a production pilot. The Board approved the DPA in Decision 2010.01. The pilot scheme allowed the Proponent to acquire static and dynamic production and injection data that has provided a better understanding of the West Pool and led to the submission of this Application. Further details on the pilot scheme results and how they influenced the depletion planning for the pool can be found in Section 4.5.1.2 below.

4.5.1.2 Pilot Scheme Results

The West Pool is a structurally complex reservoir, with a high degree of faulting, and is generally of lower reservoir quality than the South Pool, as it has lower net reservoir, and contains more prominent parasequence boundaries some of which are potential barriers to flow. The reservoir quality degrades to the north and west as the depositional environment becomes more distal.

The Proponent planned and initiated the pilot scheme to acquire dynamic production and injection data in order to improve understanding of technical risks in the West Pool and how they could best be mitigated. This information was used to develop an optimized depletion strategy for the pool and to ensure oil recovery is maximized.

The main technical risks that the pilot scheme was designed to address were:

- the lateral extent, quality and productivity of the upper reservoir facies;
- the sealing nature of the faults;
- the significance of the coarsening-upward parasequences, their level of barrier or baffle to flow, their number and extent;
- the degree of reservoir compartmentalization;
- reservoir connectivity;
- the productivity index/performance from all flow units; and
- the water injection fracture and propagation pressure.

This pilot scheme used the E-18 10 producer which began production in September 2011. It was on primary production until April 2012 when the E-18 11 water injector was drilled to provide pressure support.

E-18 10 was drilled as a highly deviated well in order for the well path to cross the JB18a fault, and to maximize crossing of multiple parasequences above the oil-water contact. E-18 11 was drilled as a slightly deviated well and targeted all parasequences. Both wells were equipped with intelligent completions. The producer was designed as a two-zone intelligent completion, with a third zone having no downhole control. The injector was designed as a three-zone intelligent completion.

The intelligent producer isolates three completion zones that cross the JB18a fault and the BNA 325 parasequence boundary, while the intelligent injector isolates three completion zones that cross the BNA 325 and BNA shell cement boundaries. The completion zones are illustrated in Figure 4.10.

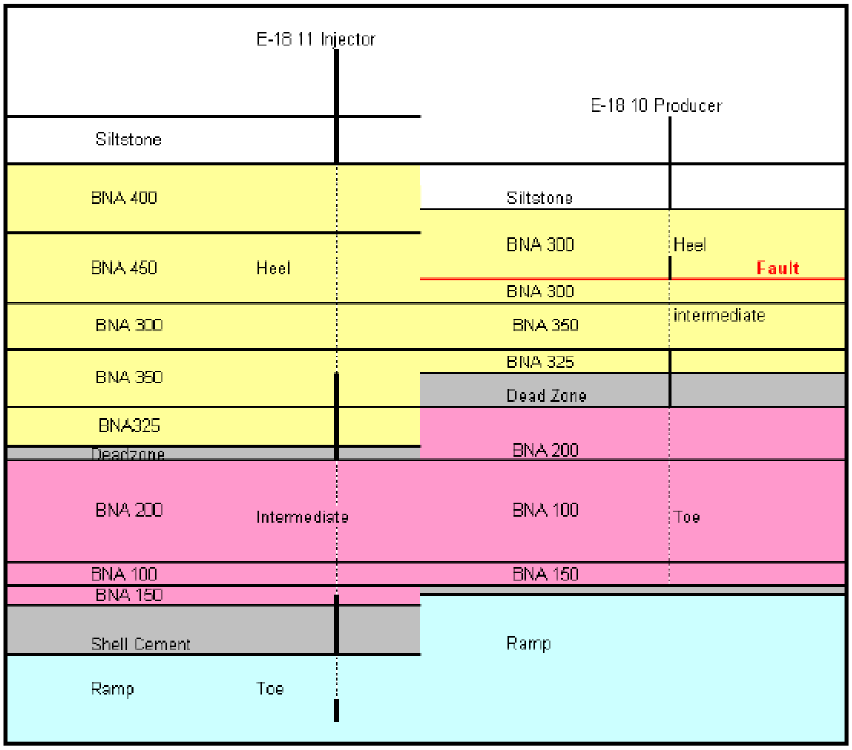

Figure 4.10: Pilot producer and injector completion zones (From Husky, 2014).

The use of intelligent completions allowed the Proponent to manipulate downhole valves to generate individual production and injection tests within the three completion zones. Furthermore, a comprehensive program of interference testing was also executed between the completion zones of the producer and injector using the intelligent completions. This interference testing allowed the Proponent to determine the extent of inter-well communication between the zones and to evaluate the sealing or baffling nature of the JB18a fault and the BNA 325 and BNA-shell cement parasequence.

Through the use of the various testing programs, the Proponent concluded that all of the original objectives of the pilot scheme were achieved. The results have resolved significant uncertainty, provided the Proponent with a much better understanding of the reservoir dynamics of the West Pool and enabled optimization of the depletion plan for the pool. Key findings are highlighted below.

- There was confirmation of oil flow from the poorer quality upper parasequences, and quantitative estimates of this flow were obtained. As a result, the Proponent has placed wells in the upper flow units to produce these reserves.
- The JB18a fault, crossed by E-18 10, was found to be highly baffling or sealing to flow. This has resulted in the Proponent designing wells that cross faults to maximize drainage and sweep of oil reserves.
- A greater understanding of parasequence boundaries and vertical barriers in the reservoir was obtained. E-18 11 vertical interference testing between the middle and upper zones and the middle and lower zones confirmed no communication across the BNA 325 or the BNA-shell cement. As a result, both parasequence layers are believed to be highly baffling or sealing and therefore, a water injection bottom-drive type displacement would not be suitable for a large portion of the West Pool. Instead much of the pool will be depleted using water injection with a lateral sweep direction.
- E-18 11 was able to achieve injection within all three completion zones and there was evidence of thermal fracturing.
- Pressure communication between E-18 10 and E-18 11 was confirmed through interference testing. This testing showed that horizontal communication is better in the middle flow units than the upper flow

units. Therefore higher density well spacing is proposed in order to maximize recovery from the upper parasequences.

- Fracture and propagation pressures were confirmed and have been used for development planning purposes.

4.5.1.3 Depletion Planning

The depletion strategy proposed for the West Pool is secondary recovery by water flood with a targeted voidage replacement ratio between 1.0 and 1.2. This is consistent with the strategy employed in the existing developments at the White Rose Field.

The Application proposes drilling 13 producers and 13 water injectors from the WHP to deplete the remaining reserves in the West Pool. With the pilot producer, pilot injector and the J-22 3 gas injector already in place, this will bring the total development well count for the pool to 29 wells. The proposed well locations and orientations are illustrated in Figure 4.11.

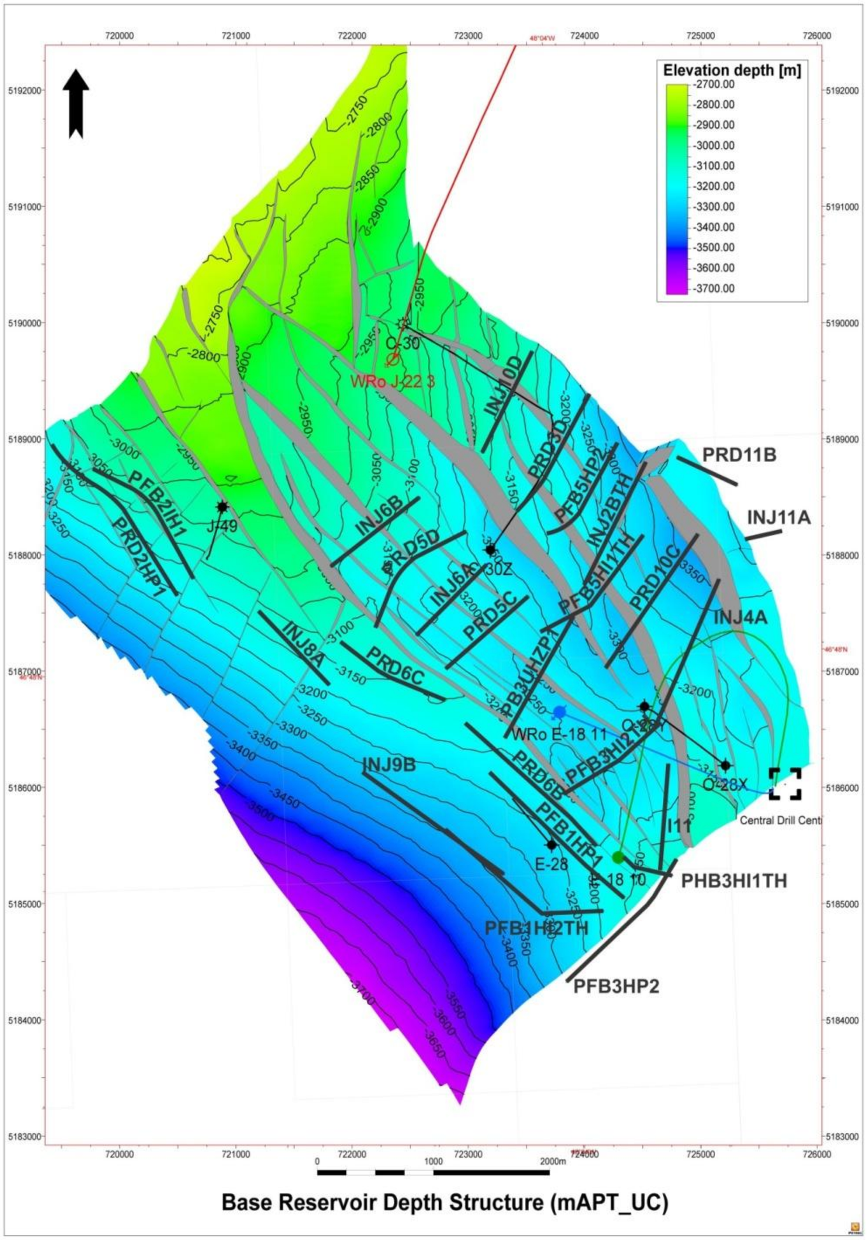

Figure 4.11: Proposed West Pool well locations (From Husky, 2014).

As detailed in Section 4.5.1.2, the static and dynamic data gained from the pilot scheme have provided the Proponent with a better understanding of the West Pool and the horizontal and vertical interfaces within the reservoir. The pilot scheme results, in conjunction with knowledge from the existing developments, have allowed the Proponent to optimize the depletion plan for the pool. This resulted in two different well placement strategies proposed for the area northeast of the J-49 fault and the area southwest of the J-49 fault, respectively (Figure 4.12).

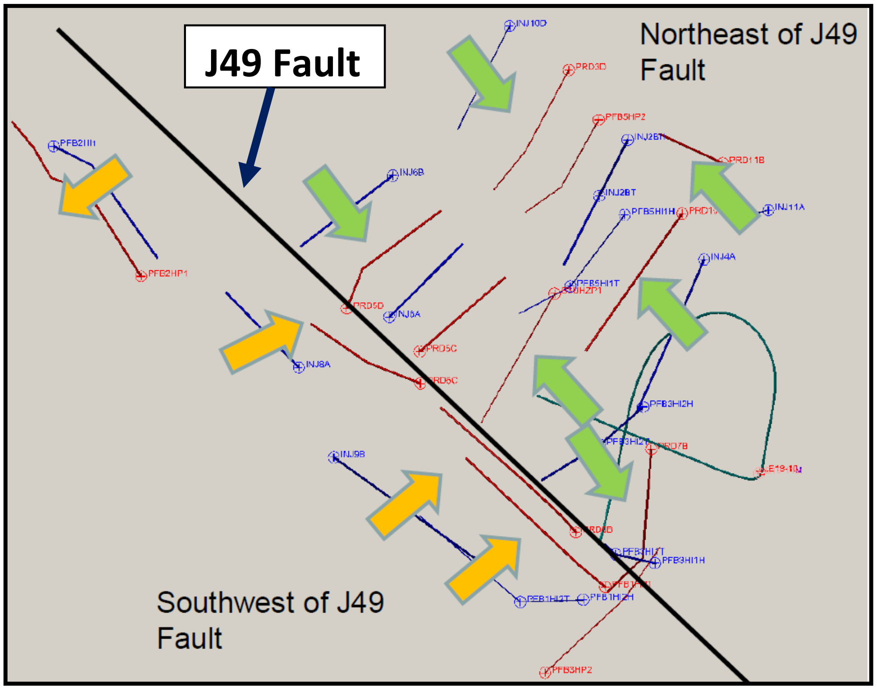

Figure 4.12: West Pool well orientation plan (From Husky, 2014).

The area to the southwest of the J-49 fault is less faulted than the region to the northeast. The proposed well placement strategy southwest of the J-49 fault is driven by the extent of the oil in place, and is analogous to the strategy employed for the North Amethyst Field with the wells being oriented northwest-southeast. The horizontal and highly deviated producers will be drilled parallel to the J-49 fault and will be supported by horizontal and highly deviated water injectors, some of which will be placed down dip for a bottom-drive water flood displacement. A bottom-drive water flood can be used in this area because it is less faulted and more continuous than the region northeast of the J-49 fault. Using down-dip water injectors and spacing the wells in this area further apart will help to mitigate any potential thermal fracture growth in the water injectors which could bypass oil pay and result in decreased recovery.

The area northeast of the J-49 fault is structurally complex with a series of post-depositional northwest-southeast trending faults that segment the reservoir into thin, rotated fault blocks. The wells in this region will generally be oriented in the northeast-southwest direction and will cross multiple faults in order to minimize the risk of decreased recovery due to sealing faults. Orienting the wells in the northeast-southwest direction will also ensure oil pay is not bypassed by thermal fractures from the water injectors as the Proponent's geomechanics analysis indicates that the maximum stress direction (fracture growth orientation) is also northeast-southwest. The Proponent indicates that as wells in the pool are drilled, well orientations will be examined and possibly adjusted as fracture and stress direction understanding evolves.

The depletion strategy for the area northeast of the J-49 fault will use producers and water injectors which are either highly deviated or horizontal. The strategy is driven by the structure and low vertical permeability of the reservoir. Placing wells to cross multiple parasequences, especially in the upper flow units where permeability is lower, will enable the Proponent to achieve a higher sweep efficiency and lead to higher ultimate recovery from the pool.

The poorer reservoir quality and permeability of the upper parasequences has also influenced the Proponent's well spacing in the area north of the J-49 fault, where a higher density of wells will be required in order to ensure reservoir pressure is adequately maintained and depletion of the oil in place is maximized.

The Proponent's depletion and well placement strategy in this area is also influenced by the BNA 325 and BNA Shell Cement parasequences which are believed to be horizontal barriers or baffles to flow. The use of deviated wells which pass through these interfaces will ensure reserves above and below them are swept and receive proper pressure support. These sealing parasequences are the reason a bottom-drive water flood displacement would not be suitable for this area, and why a lateral drive/sweep type water flood is proposed.

The exception to the well placement strategies on both sides of the J-49 fault will be the producer and injector pairs indicated in Figure 4.13. These well pairs will be located in the area of the West Pool gas cap. Details on the Proponent's estimate of the extent of the gas cap are shown in Figure 4.14.

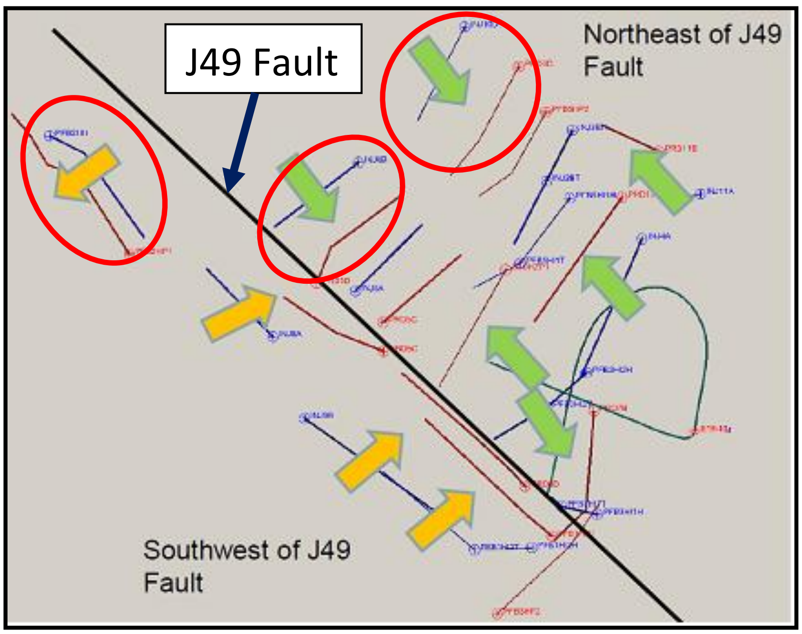

Figure 4.13: Well placement strategy in proximity to the gas cap (from Husky, 2014).

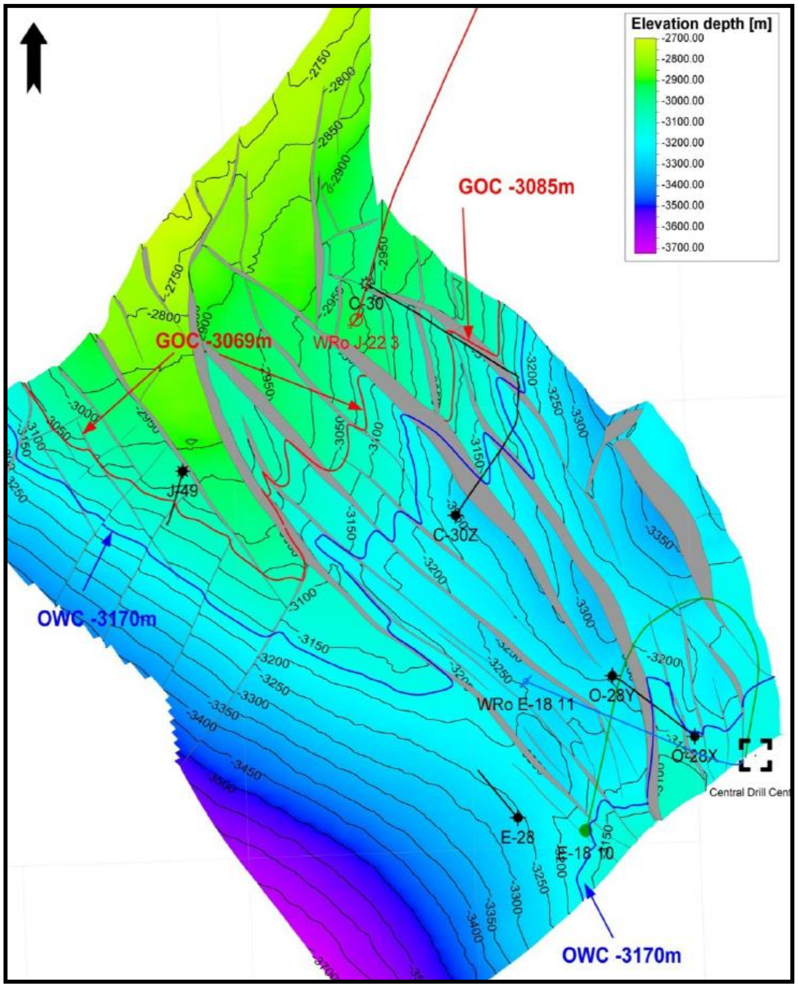

Figure 4.14: Map illustrating location of gas cap and OWC in the West Pool (From Husky, 2014).

For the well pairs in the gas cap area, the Proponent is currently planning to place the water injectors at the gas-oil contact and structurally higher than the producer. This approach is preferred because simulation modelling has demonstrated that water injection at the gas cap will help to hold the free gas back from the producer and delay gas breakthrough and GOR development at the producers, leading to higher oil recovery from these areas.

This gas hold-back strategy has yet to be tested at the White Rose Field, but the Proponent is considering implementing it in the South Pool through the drilling of future wells or the recompletion of existing wells. As such, the Proponent may have some production data and experience with this type of scheme before these wells pairs come online on the WHP. Simulation modelling conducted by staff has also found that oil recovery in these areas could be severely impaired due to early gas breakthrough and GOR increase in the producers. For this reason, **staff is not opposed to the proposed gas hold-back depletion strategy for these well pairs, but the Proponent may be required to provide further technical analysis before this strategy is implemented.**

From a well scheduling standpoint, the Proponent plans to drill wells in the area close to the E-18 10 pilot producer first, where the reservoir quality is known. Drilling will then step out incrementally from south to north to gain insights on variables such as facies distributions and the location of the gas cap. The Proponent plans to use the reservoir information gathered to optimize and adjust the well placement strategy for the West Pool.

Staff is in agreement with the West Pool depletion plan as detailed in the Application, and finds it to be reasonable and appropriate.

4.5.1.4 Reservoir Simulation

To support the Application, the Proponent submitted an ECLIPSE reservoir simulation model for the West Pool. The simulation model was based on a geological static model built in Petrel, which incorporated data from the West Pool delineation wells and additional data obtained from drilling the pilot scheme producer and injector. The geological model was statistically populated and then upscaled from 50m x 50m to approximately 100m x 100m to reduce the number of grid cells to allow for a more manageable dynamic simulation. The Proponent applied a uniform upscaling ratio of 2:1 in both horizontal directions. For the vertical direction a variable upscaling ratio was used in an attempt to represent the inherent heterogeneity of the reservoir. The resulting West Pool simulation model has 60 x 79 x 350 cells for a total of 1.65 million cells.

The West Pool relative permeability data, fluid characterization, equilibrium characteristics and fluid contacts as outlined in the Application and Section 4.4 were then applied to the upscaled simulation grid. To initialize the model, the Proponent used saturation logs and a co-kriged geostatistical distribution to generate a water saturation distribution. As a result, the Proponent's simulation model has a deterministic STOOIP estimate of 69.0 MMm^3 (434 MMbbls) compared to the P50 probabilistic estimate of 72.9 MMm^3 (458.5 MMbbls).

The Proponent used observed daily production and water injection rates and pressure data from the pilot scheme producer and injector to history match the model prior to performing predictive cases. Additional information obtained from the pilot scheme, such as the sealing nature of the JB18a fault and the BNA325 and BNA Shell Cement parasequences, were also incorporated. As a result of the history matching, the Proponent made modifications to the model permeability and relative permeability endpoints to achieve the best possible match. Other history match modifications include the sealing of the bottom six layers of the both the BNA325 and BNA Shell Cement parasequences, the sealing of the JB18a fault down to the base of the BNA325 parasequence and the application of a 90 percent seal on all remaining faults down to the same parasequence.

Details of the Proponent's depletion scheme, planned well locations, well scheduling, well production and injection constraints were incorporated into the history matched model to simulate the base-case results for the West Pool. The well schedule used in the model assumed the first West Pool well would come online January 1, 2017, which is very close to the November 2016 online date in the drill schedule included in the Application. Further details on this drill schedule can be found in Section 4.5.5. The drill schedule used in the model differs from the drill schedule in the Application, as the model development strategy assumes all 26 West Pool wells are drilled and online over a five-year period instead of seven years. The schedule used in the model generally honours the same well drilling sequence in the WHP drill schedule, but there are some exceptions. The model also assumes the West Pool produces to the year 2030.

The resulting recoverable oil from the base-case depletion scenario within the Proponent's simulation model is 16.65 MMm^3 (104.7 MMbbls). This recoverable volume equates to a 24 percent recovery factor under the proposed water flood depletion scheme, and is comparable to the Proponent's probabilistic P50 recoverable estimate of 17.1 MMm^3 (108 MMbbls). Further details on the Proponent's reserve estimates can be found in Section 4.8. The simulation model provided did not account for any additional recoverable volume from the use of technologies such as ESPs and hydraulic fracturing from the WHP. However, the Proponent has indicated that simulation modelling work that was performed taking these technologies into account resulted in an increased recoverable of 18.28 MMm^3 (115 MMbbls) when compared to the base-case simulation model provided.

It should be noted that the recoverable oil estimate from the Proponent's model does include production from the E-18 10 pilot scheme producer. The model predicts the ultimate recovery from E-18 10 to be 2.17 MMm^3 (13.6 MMbbls). Therefore, the incremental recovery predicted from the WHP by simulation is 14.9 MMm^3 (94 MMbbls), compared to the Proponent's probabilistic P50 incremental recoverable estimate of 14.8 MMm^3 (93 MMbbls).

For analysis of the Application, staff created a reservoir simulation model for the West Pool using the Petrel Reservoir Engineering core. This model was built using a geological model developed by geoscience staff in Petrel. The geological model was based on staff's independent assessment of available West Pool geological and petrophysical data. The geological model was based on an older vintage structural interpretation than was used for the Proponent's model, and it also used staff's interpreted fluid contacts. Details on staff's geological modelling work can be found in Appendix B.

To minimize simulation run times, the 50m x 50m geological model was upscaled to 100m x 100m in a similar manner to the Proponent's model. The resulting West Pool simulation model contains 68 x 97 x 155 cells for a total of 1.02 million cells. The Proponent's fluid data, relative permeability functions, rock compaction functions and similar equilibrium regions were used in staff's simulation model.

Staff's model also used the Proponent's development strategy and well and group rate production, pressure, injection and voidage constraints. In general, the same well locations were used in staff's model; however, due to differences in structural interpretation, interpreted fluid contacts and property modelling, some slight modifications to well trajectories and completions had to be made in order to produce adequate volumes from some wells. These adjustments were made while attempting to honour the Proponent's intended flow unit targets for the respective wells.

The resulting recoverable oil from staff's base-case simulation model is 17.3 MMm^3 (108.8 MMbbls), which is similar to the 16.65 MMm^3 (104.7 MMbbls) recoverable predicted by the Proponent's model. However, the recovery factor achieved by staff's model only equates to 14.4 percent compared to the 24 percent recovery factor estimated from the Proponent's model. This difference is due to the estimated 119.7 MMm^3 (753 MMbbls) STOOIP in staff's simulation model being considerably larger than the 69.0 MMm^3 (434 MMbbls) STOOIP estimated in the Proponent's model. Further details on the reservoir simulation work performed by staff and the results can be found in Appendix D.

In addition to independent simulation work, staff also performed a thorough review of the Proponent's simulation model and held numerous consultations on the modelling with the Proponent. Generally, staff found the Proponent's model and the assumptions used to be reasonable and appropriate.

4.5.1.5 Production Performance

The Application contains production profiles for West Pool oil, water and gas production rates. These profiles are included in Figure 4.15, 4.16 and 4.17, respectively. The forecasted rates result from incorporating the history matched reservoir simulation results into a full-field integrated production model. The integrated production model includes facility constraints and downtime for anticipated facility turnarounds.

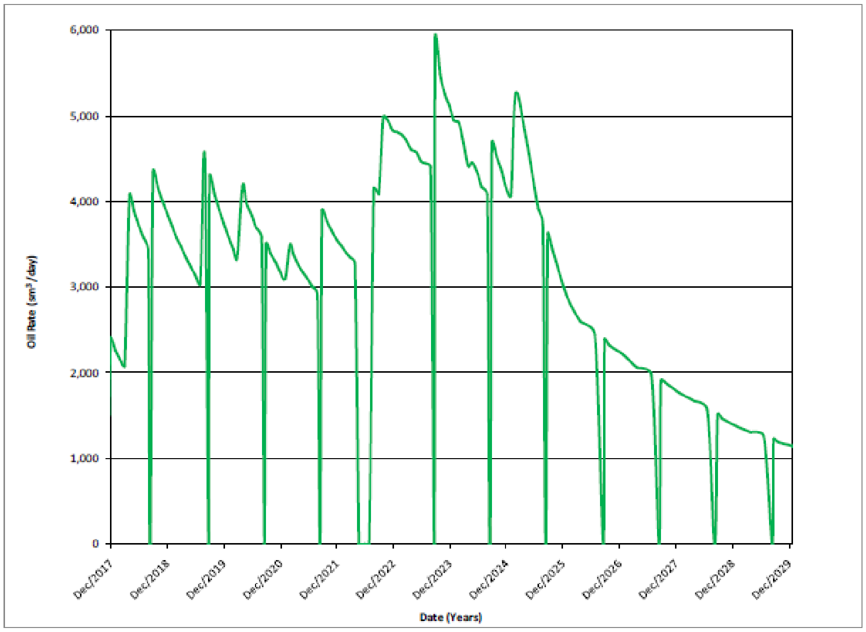

Figure 4.15: Predicted West Pool oil production profile (From Husky, 2014).

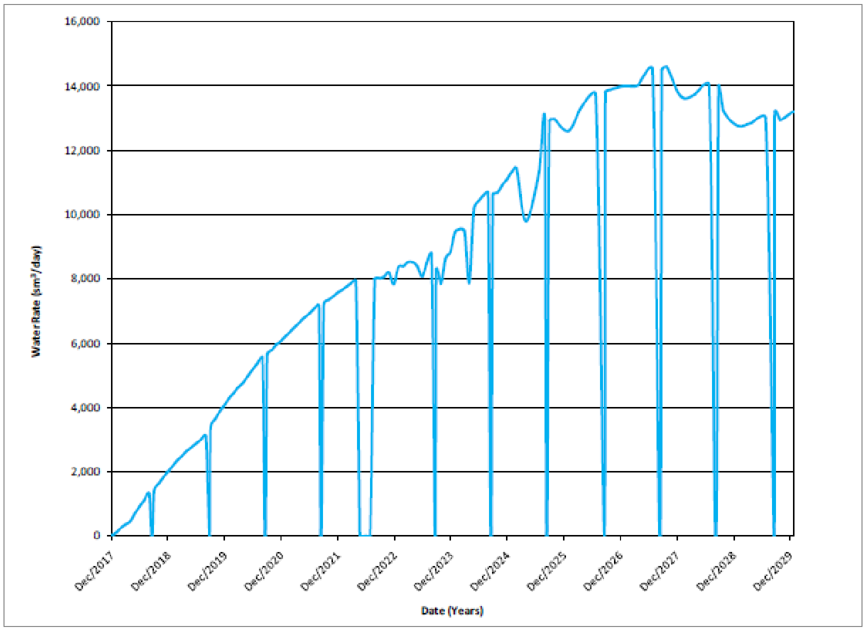

Figure 4.16: Predicted West Pool water production profile (From Husky, 2014).

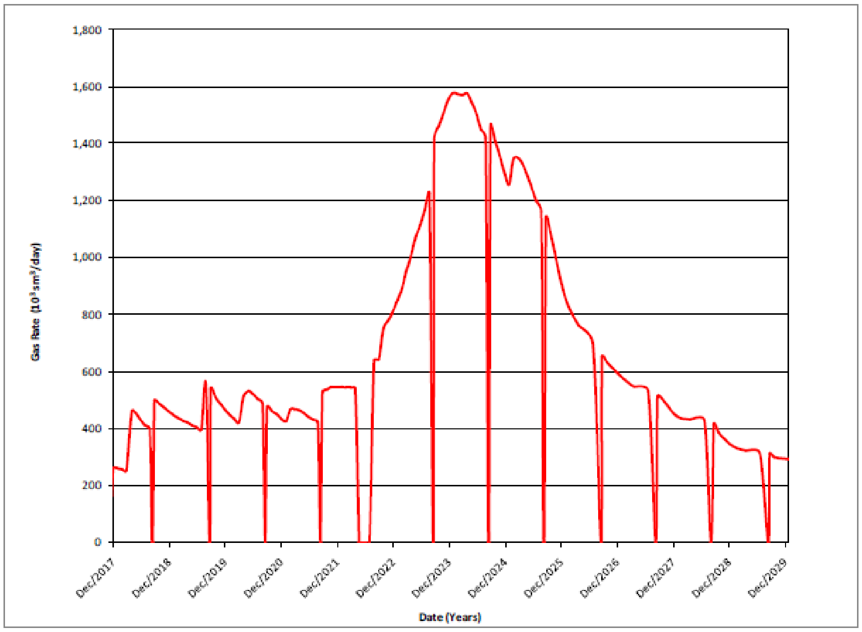

Figure 4.17: Predicted West Pool gas production profile (From Husky, 2014).

4.5.2 North Pool

4.5.2.1 History

The North Pool contains a large gas cap with an associated oil rim down dip to the south. The pool is comprised of several fault blocks which are believed to be compartmentalized. This compartmentalization results from thin reservoir being juxtaposed against non-reservoir across the fault blocks.

The gas cap of the North Pool was identified as the best gas storage location in the White Rose Development Plan. To date, the pool has only been used to store produced gas from other areas of the White Rose Asset for gas conservation purposes.

The oil resources of the North Pool were not proposed for development in the White Rose Development Plan. The pool was considered a deferred development at that time, as the Proponent wished to acquire additional drilling, production and injection data before proceeding with development of North Pool oil resources. Staff concurred with the Proponent in Decision 2001.01 that additional information and assessment was required prior to proceeding with development of the pool.

Since Decision 2001.01, geological understanding of the North Pool has evolved due to drilling results from the K-03 delineation well and the drilling results and performance data from the J-22 1 and J-22 2 gas injection wells. This improved understanding has resulted in a decrease in interpreted reservoir quality and thickness and has hence led to a significant decrease in the Proponent's oil and gas in-place estimates for the pool. Further details on the in-place estimates for the North Pool can be found in Section 4.3.

4.5.2.2 North Pool Depletion Planning

The depletion strategy proposed for the North Pool is secondary recovery by water flood with a targeted voidage replacement ratio between 1.0 and 1.2. This strategy is based on the Proponent's reservoir simulation modelling and current probabilistic reserve estimates.

The proposed depletion strategy uses a single producer and water injector well pair. The producer will be drilled near horizontal in the middle of the oil leg. It will be placed at the southern edge of the North Pool oil rim, along a bounding fault. The producer will intersect several parasequences due to the dipping nature of the reservoir in this area. The highly deviated water injector will be drilled in a near-parallel orientation, to the northeast of the production well. In order to maximize vertical sweep, the water injector will also intersect several parasequences.

The proposed North Pool well locations and orientations can be seen in Figure 4.18.

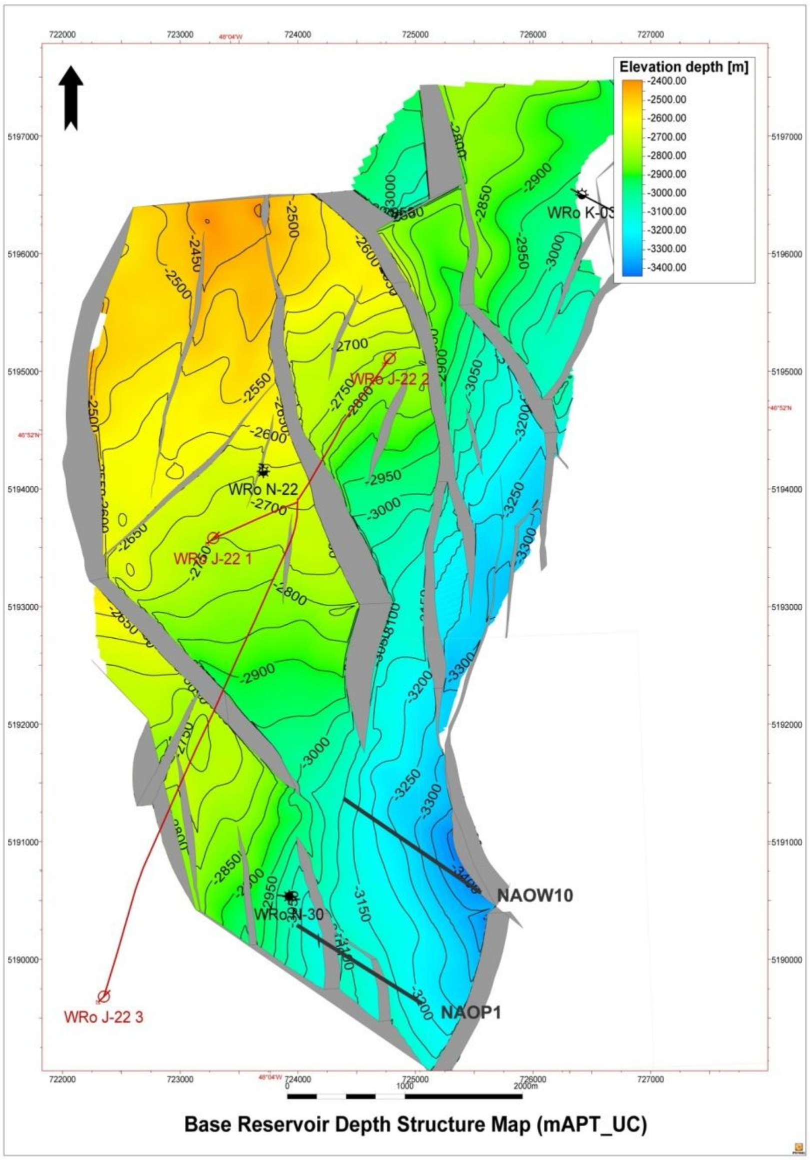

Figure 4.18: Proposed North Pool well locations (From Husky, 2014).

The Proponent used information from the developed White Rose Asset pools as the basis for North Pool depletion planning. This planning also considered the increased technical functionality and improved drilling efficiency provided by using the WHP. Staff is in agreement with the North Pool depletion plan as detailed in the Application, and finds it to be reasonable and appropriate.

4.5.2.3 North Pool Reservoir Simulation

The Proponent submitted an ECLIPSE reservoir simulation model for the North Pool to support the Application. The simulation model was based on a geological static reservoir model built in Petrel that incorporated data from North Pool wells N-30, J-22 1 and J-22 2, in addition to regional data from surrounding White Rose development and exploration wells.

After the Proponent's 50m x 50m geological model was statistically populated, it was then upscaled to reduce the number of grid cells to allow for more manageable dynamic simulation. As many of the North Pool fault blocks contain only gas overlying water, the Proponent cut down the grid used for the simulation cases to focus on the oil-rim fault blocks in the N-30 delineation well area. Staff found this to be acceptable, as the oil rim in this area is the focus of the North Pool development and the gas filled fault blocks are not believed to be in communication with the oil bearing blocks. As a result, the Proponent's upscaled dynamic grid contains 70 x 179 x 396 cells for a total of 4.9 million cells. The upscaling was achieved by applying a uniform 2:1 upscaling ratio in both horizontal directions. In order to preserve the inherent heterogeneity of the pool, the Proponent did not perform any vertical upscaling.

The water saturation distribution was generated using well logs and a co-kriged geostatistical distribution, and was used to initialize the simulation model. As a result, the Proponent's predictive simulation model has a deterministic STOOIP estimate of 6.394 MMm^3 (40.2 MMbbls) compared to the P50 probabilistic estimate of 6.2 MMm^3 (39 MMbbls).

The North Pool relative permeability data, fluid characterization, equilibrium characteristics and fluid contacts, as outlined in the Application and Section 4.4, were then applied to the upscaled simulation grid.

The development strategy used for the predictive cases for the Proponent's model included details on the proposed depletion scheme, planned well locations, well scheduling and well production and injection constraints. The well schedule used in the model assumes the North Pool producer and injector come online January 1, 2019, which is approximately three years earlier then the WHP drill schedule included in the Application. Further details on this drill schedule can be found in Section 4.4.5.5. The model also assumes the North Pool produces out to the year 2033.

The resulting recoverable oil from the base-case depletion scenario within the Proponent's simulation model is 0.88 MMm^3 (5.6 MMbbls), which is slightly higher than the Proponent's probabilistic P50 recoverable estimate of 0.6 MMm^3 (3.77 MMbbls). The recoverable volume from the simulation model equates to a 13.8 percent recovery factor, compared to the Proponent's probabilistic P50 recovery factor of 9.7 percent. Further details on the Proponent's reserve estimates can be found in Section 4.8.

For analysis of the Application, staff developed an independent North Pool simulation model using the Petrel Reservoir Engineering core. The model was built using a geological model developed by geoscience staff in Petrel. The geological model was based on independent assessment of the available geological and petrophysical data for the North Pool. The geological model was developed using an older vintage structural interpretation than that used for the Proponent's model. Details on staff's geological modelling work can be found in Appendix C.

Staff's 50m x 50m geological model covered the entire North Pool and contained 136 x 202 x 165 cells, resulting in a total of 4.5 million cells. Instead of upscaling the grid to 100m x 100m, the grid was cut down to include only the oil bearing fault blocks in the N-30 delineation well area, as was done by the Proponent. This resulted in staff's simulation grid containing 45 x 66 x 165 cells for a total of 0.49 million cells.

For the predictive cases in ECLIPSE, the Proponent's fluid model, relative permeability functions and rock compaction functions were used in staff's simulation model. For the base case, staff also used a similar development strategy to the Proponent with the same well and group rate production, pressure, and injection constraints in addition to the same location for the proposed water injector. It was not possible to use the same location for the producer however, due to considerable difference in the structural interpretation in the structural data that staff used. As a result the base-case simulation used two producers in an attempt to access the same oil pay as the Proponent's production well. Both of the producers were located in the general area of the Proponent's well, but they were placed at different depths in the oil column. Staff's producers were also perforated at different intervals than the Proponent's due to the differences in property distribution between the two models.

The resulting recoverable oil from staff's base-case simulation model is 0.71 MMm^3 (4.5 MMbbls), which is slightly lower than the 0.88 MMm^3 (5.6 MMbbls) recoverable predicted by the Proponent's model. However, the recovery factor achieved by staff's model equates to only 8 percent compared to the 14 percent recovery factor estimated from the Proponent's model. This difference is due to the estimated 8.88 MMm^3 (55.8 MMbbls) STOOIP in staff's model being larger than the 6.4 MMm^3 (40.3 MMbbls) STOOIP estimated in the Proponent's model. Further details on the reservoir simulation work performed by staff and the results can be found in Appendix D.

In addition to independent simulation work, staff performed a thorough review of the Proponent's North Pool simulation model and also held numerous consultations on modelling with the Proponent. Overall, staff found the Proponent's model and the assumptions used to be reasonable and appropriate.

4.5.2.4 North Pool Production Performance

The Application contains production profiles for North Pool oil, water and gas production rates. These predicted profiles are illustrated in Figure 4.19, 4.20 and 4.21, respectively. The rates result from incorporating reservoir simulation results into a full-field, integrated production model. The integrated production model includes facility constraints and downtime for anticipated facility turnarounds.

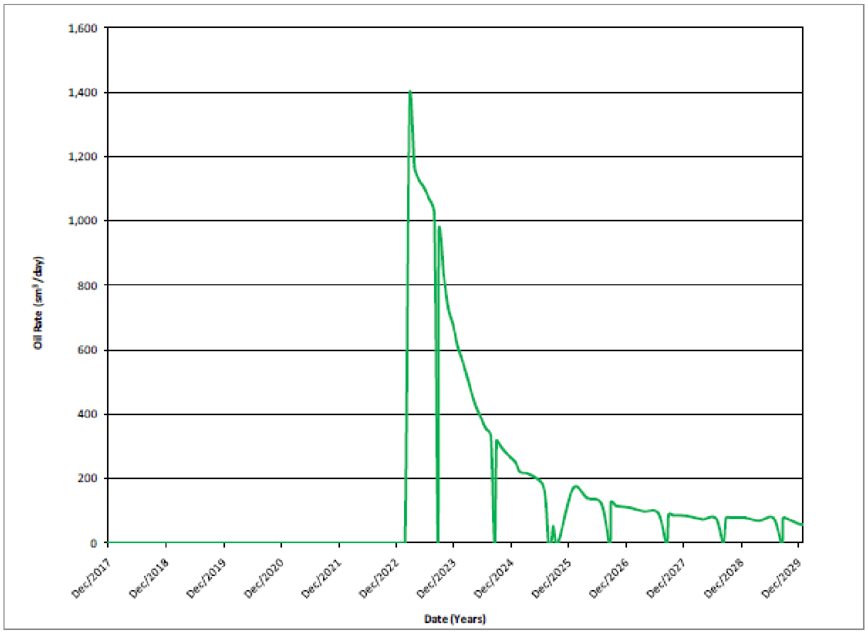

Figure 4.19: Predicted North Pool oil production profile (From Husky, 2014).

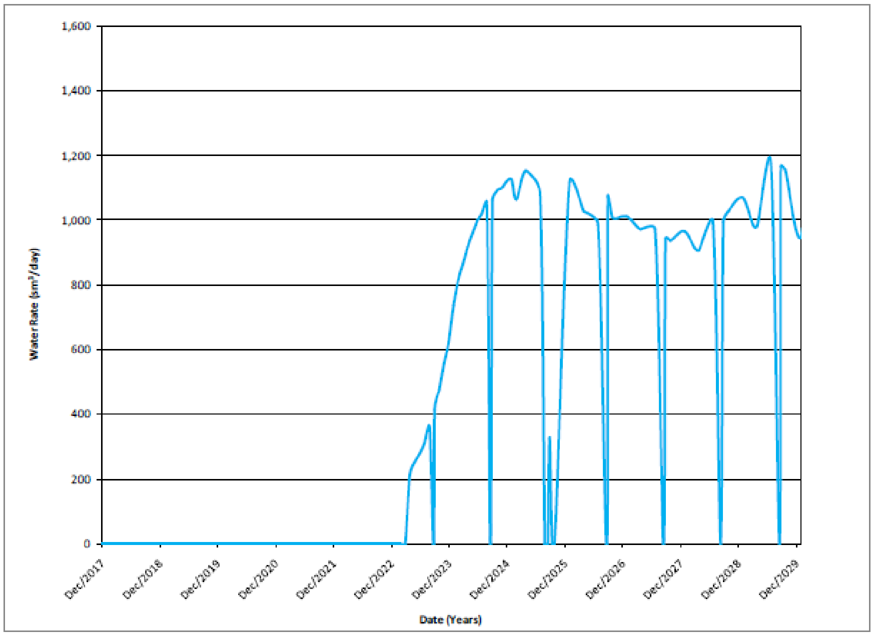

Figure 4.20: Predicted North Pool water production profile (From Husky, 2014).

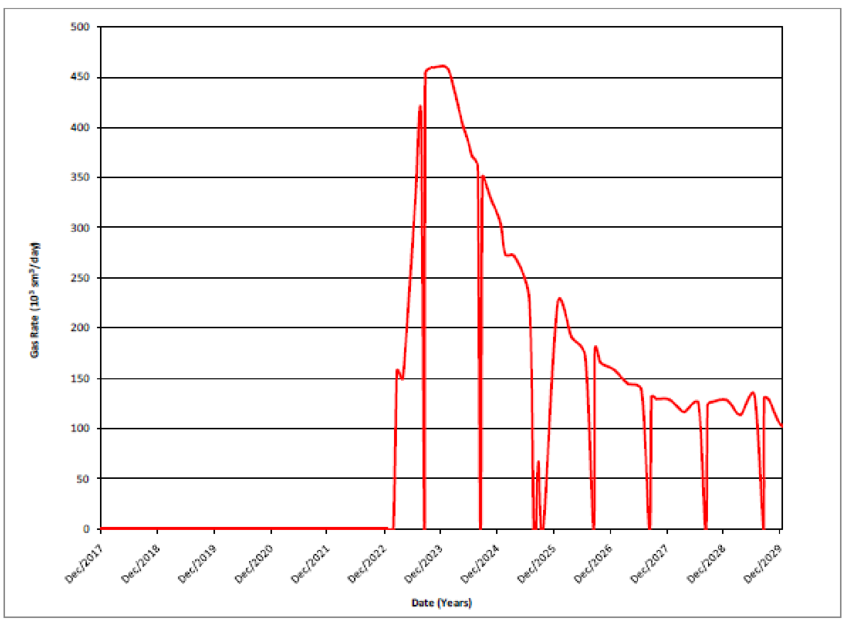

Figure 4.21: Predicted North Pool gas production profile (From Husky, 2014).

4.5.3 South Pool - Blocks 2 and 5

4.5.3.1 History

While Blocks 2 and 5 are considered part of the South Pool, the Proponent indicated in the initial White Rose Development Plan (2001) that they may be too small to economically produce and were therefore only considered in the upside resource case. As a result, the base-case development for the South Pool excluded drilling of these blocks at that time. Staff concurred with the Proponent's approach for the blocks and noted in Decision 2001.01 that future extension of the proposed South Pool water flood depletion scheme the into these fault blocks would be covered under the approval.

Blocks 2 and 5 comprise the undeveloped northern extent of the South Pool. They contain higher quality reservoir than the West and North pools, due to a more proximal depositional environment, resulting in cleaner, coarser grained sands. There are few vertical baffles/barriers to flow. The Application proposes that development of Blocks 2 and 5 be from the WHP, due to the increased technical functionality and improved drilling efficiency it will provide.

4.5.3.2 Blocks 2 and 5 Depletion Planning

The depletion strategy proposed for Blocks 2 and 5 is very similar to that being employed for the South Pool, and is based on the geological structure and fluid contacts in each block. The strategy involves placing horizontal production wells in the oil column with underlying horizontal water injectors to provide vertical pressure support from below. In an attempt to maximize recovery, the horizontal production wells may be placed higher in the oil column when compared to the South Pool where producers are located in the middle of the column. The reasons for this are two-fold: Blocks 2 and 5 have smaller gas caps when compared to the South Pool, and South Pool has had relatively low gas breakthrough to date. Placing the producers higher in the oil column will allow for production of attic oil which would otherwise be unswept.

The Application proposes a depletion plan that involves one horizontal producer in each of Blocks 2 and 5 and one horizontal water injector, with intelligent completion, that would be drilled through both blocks. The well locations and orientations are illustrated in Figure 4.22.

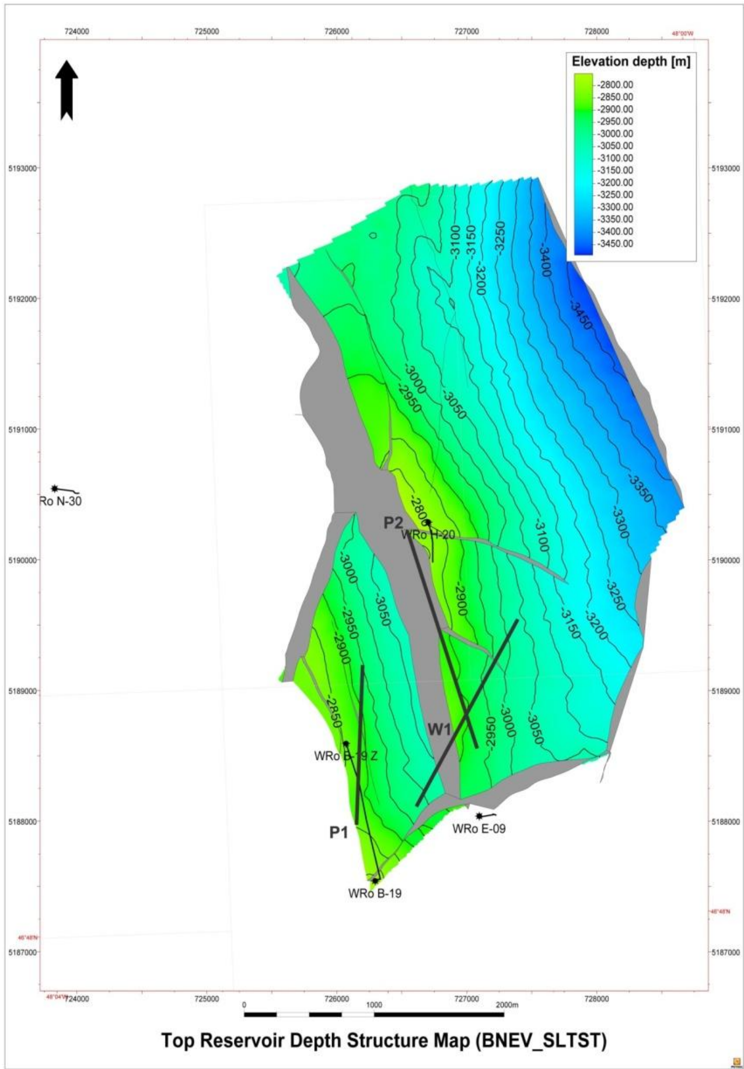

Figure 4.22: Proposed Blocks 2 and 5 well locations (From Husky, 2014).

In order to avoid potential baffling from any individual parasequence boundary, the horizontal water injector will be drilled to intersect as many parasequences as possible. The intelligent completion will allow water to be independently injected in each of the blocks. This proposed intelligent completion in the water injector leverages what has been learned from the South Pool and North Amethyst Field, where intelligent water injectors are currently used for injection into multiple fault blocks. A voidage replacement ratio between 1.0 and 1.2 will be targeted.

Staff is encouraged that the Proponent has used information gained from currently producing White Rose Asset pools to inform depletion planning for Blocks 2 and 5. This planning also takes into account the increased technical functionality and improved drilling efficiency provided by the WHP. Staff is in agreement with the Blocks 2 and 5 depletion plan as detailed in the Application, and finds it to be reasonable and appropriate.

4.5.3.3 Block 2 and 5 Reservoir Simulation

Blocks 2 and 5 were included in the geological model for the North Pool; however the Proponent did not provide a reservoir simulation model for Blocks 2 and 5 as it was still under development at the time of Application submission.

Staff expects the Proponent to submit updated geological and reservoir simulation models for Blocks 2 and 5 in the annual update to the Resource Management Plan.

4.5.3.4 Block 2 and 5 Production Performance

The Application contains production profiles for Blocks 2 and 5 oil, water and gas production rates. As the simulation model for Blocks 2 and 5 was still under development at the time of Application submission, recoverable reserve estimates listed in the Application were based on probabilistic analysis performed by the Proponent. Analogous wells in the Terrace and Central blocks of the South Pool were used as part of this analysis to generate production profiles for Blocks 2 and 5. The resulting production forecast was then incorporated into a full-field integrated production model which takes into account facility constraints and downtime for anticipated facility turnarounds.

The predicted profiles for Blocks 2 and 5 oil, water and gas production are illustrated in Figure 4.23, 4.24 and 4.25, respectively.

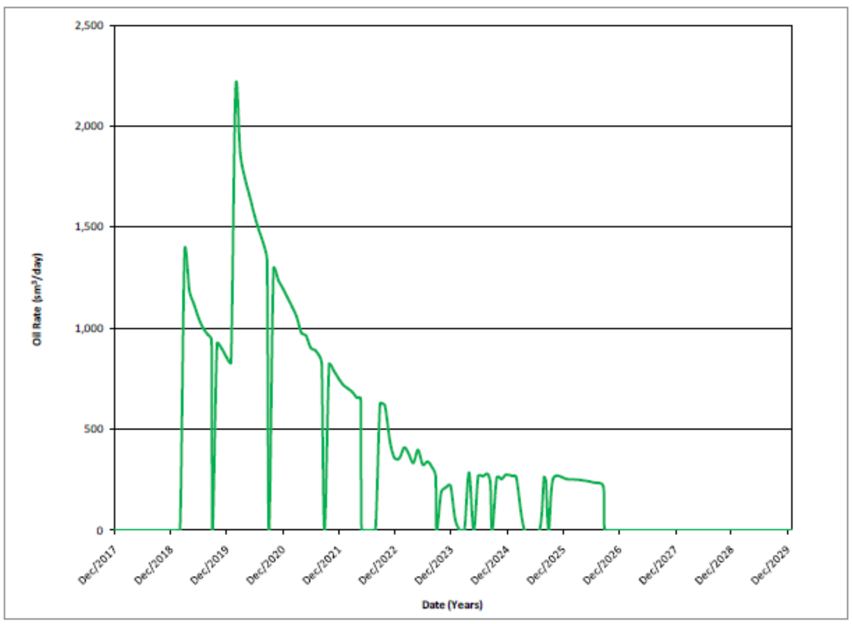

Figure 4.23: Predicted Blocks 2 and 5 oil production profile (From Husky, 2014).

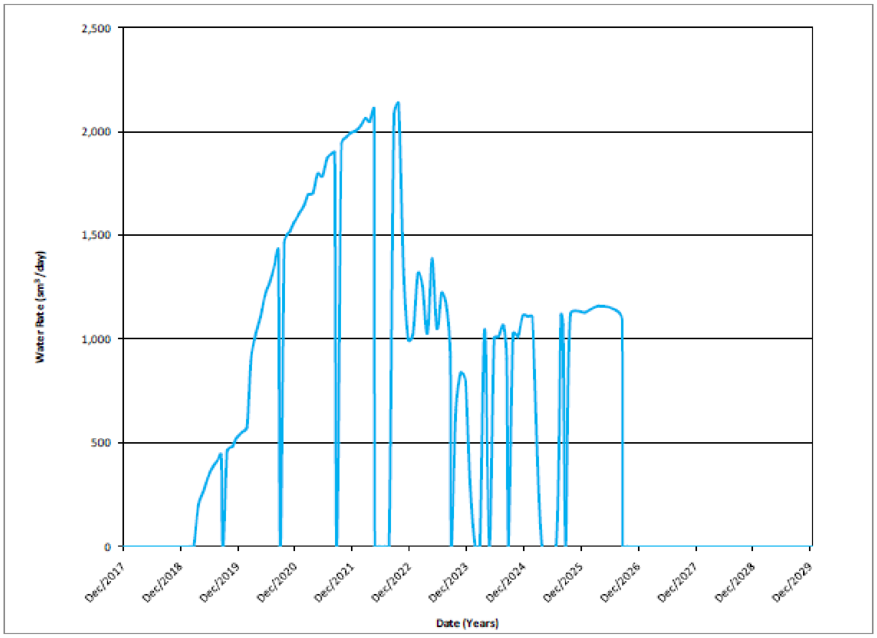

Figure 4.24: Predicted Blocks 2 and 5 water production profile (From Husky, 2014).

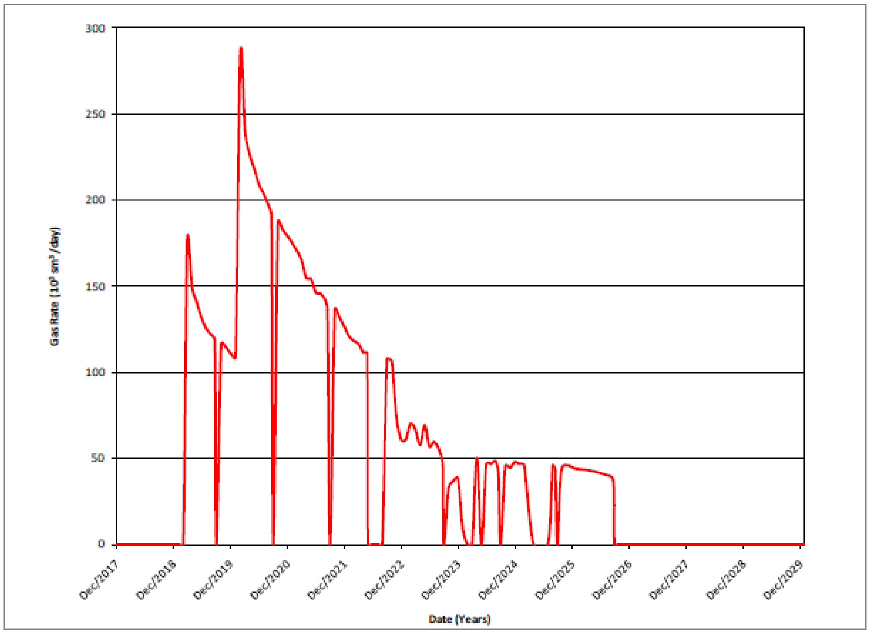

Figure 4.25: Predicted Blocks 2 and 5 gas production profile (From Husky, 2014).

4.5.4 South Pool – Central and Terrace Blocks

4.5.4.1 History

The South Pool has the largest STOOIP and EUR of all the pools in the White Rose Asset Area. It was the only pool proposed for development at the time of Decision 2001.01. The developed portion of the pool includes the Central and Terrace blocks (Figure 3.1). There have been 29.9 MMm^3 (187.97 MMbbls) of oil produced from the South Pool to date.

4.5.4.2 South Pool Existing Depletion Plan

The original depletion plan for the South Pool called for secondary recovery and pressure support by water flood. Since production commenced, the Proponent has strived to achieve a voidage replacement ratio of 1.0 to 1.2 while maintaining the reservoir pressure at or above the saturation pressure.

The Central and Terrace blocks were both originally developed with four horizontal producers and five water injectors (all highly deviated or horizontal) drilled from the Central and Southern Drill Centres. In an effort to delay the production of gas from the overlying gas caps, the producers in both blocks were placed in the middle of the oil column with underlying water injectors placed in the water leg where possible. Where horizontal water injectors were required to inject into multiple fault blocks, they were equipped with intelligent completions.

The placement of the horizontal producers in the middle of the oil column has resulted in areas of unswept attic oil in both the Central and Terrace blocks. For this reason, after drilling the eight original base-case production wells, the Proponent decided to drill the B-16 10z (2008) and B-16 11 (2012) infill production wells to target areas of unswept attic oil and increase the oil recovery from the Terrace Block. Both of these infill wells have been successful in meeting their objectives. To date, the B-16 10z well has produced 0.77 MMm^3 (4.86 MMbbls) of oil while the B-16 11 well has produced 1.11 MMm^3 (6.97 MMbbls) of oil.

Based on the success of the currently producing infill wells in the Terrace Block, the Proponent plans to drill a new infill well in the southern portion of the Terrace in 2015. The drilling of this well was addressed in the “White Rose Development Plan Amendment – South White Rose Extension Tie-back” which was approved in Decision 2013.04. That amendment also detailed the Proponent’s plans to drill a gas injector in the gas cap of the southern Terrace in order to augment the existing water-flood-only depletion scheme with gas flooding of the remaining oil resources in that area. This switch in the depletion strategy was mainly driven by the need for gas storage capacity for the White Rose Asset but also aimed to maximize oil production by enabling enhanced oil recovery through gas flooding in the southern Terrace area. Gas flooding in this area should commence in late 2015 after the gas injection well is drilled and completed.

4.5.4.3 South Pool Incremental Depletion Planning from the WHP

As a result of the Proponent’s success with infill production wells to date, the Application proposes drilling additional infill wells in the South Pool from the WHP. These infill horizontal producers would target areas with the largest unswept attic oil accumulations in the Central and Terrace Blocks. The Application also proposes the use of gas injection and/or WAG injection into the various gas caps of the South Pool to displace the unswept attic oil down toward to the future infill wells and existing producers lower in the oil column. These gas injection wells and potential WAG injection wells would also be drilled from the WHP.

At this time, the Proponent is planning to drill one horizontal infill producer in the Terrace Block and two horizontal infill producers in the Central Block from the WHP. Each of these blocks will also have one gas injector drilled from the WHP. The Terrace Block gas injector will be highly deviated and located in the gas cap of the northern Terrace while the Central Block gas injector will be drilled horizontally. The locations of the infill production and gas injection wells being considered by the Proponent are illustrated in Figure 4.26. It is notable that the Proponent continues to perform enhanced oil recovery studies and as such, these well locations may change over time.

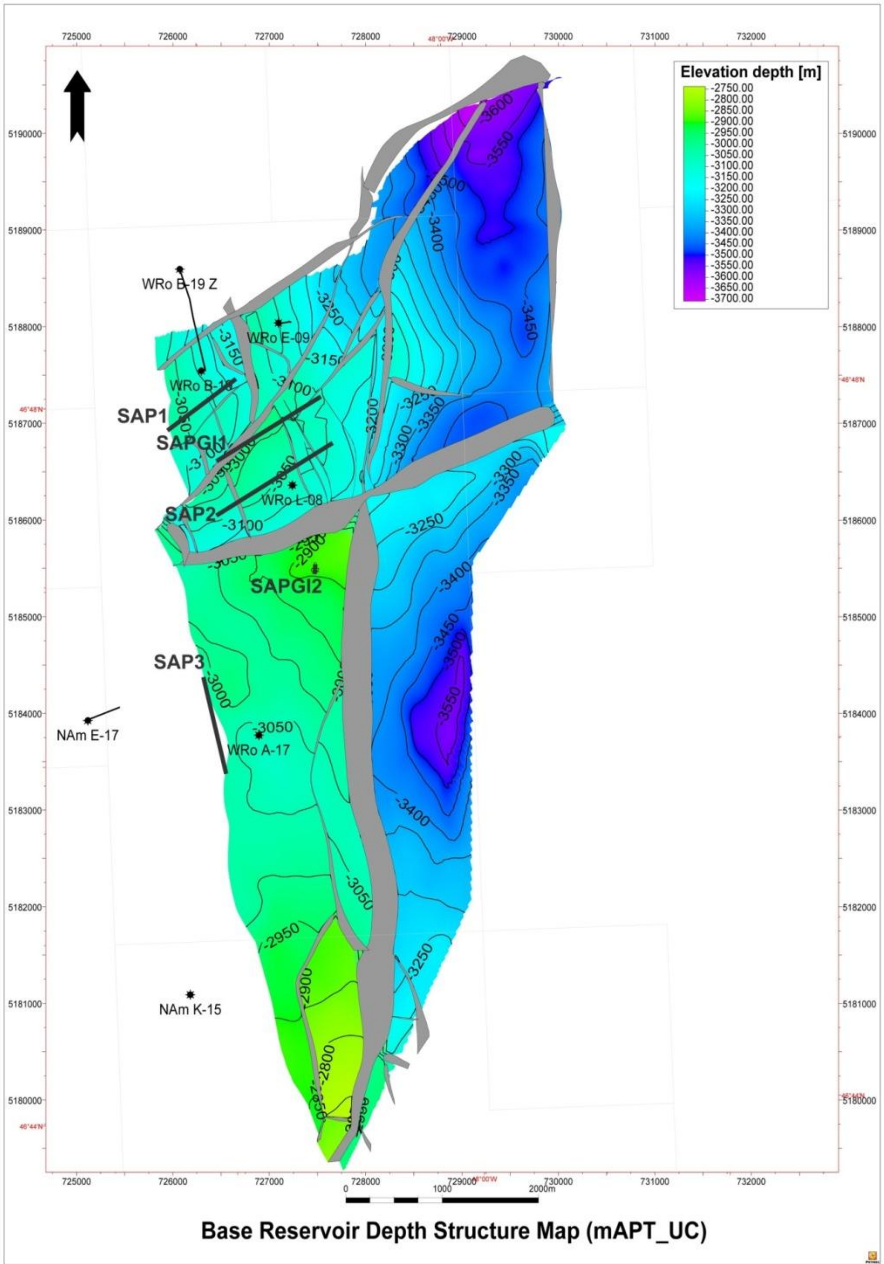

Figure 4.26: Proposed South Pool infill producer and gas injector locations (From Husky, 2014).

With the exception of the addition of gas and/or WAG flooding to the currently existing water flood strategy, the reservoir depletion strategy for the South Pool will remain unchanged. A voidage replacement ratio between 1.0 and 1.2 will be maintained, and the reservoir pressure will continue to be kept above bubble point.

Staff concurs with the Proponent's revised depletion strategy for the South Pool and the plans to add incremental South Pool oil production from the WHP. The Proponent will use knowledge gained from the existing infill producers and other wells to optimize the well deign of the infill producers and gas injection wells to be drilled from the WHP.

4.5.4.4 South Pool Reservoir Simulation

The Proponent submitted an ECLIPSE reservoir simulation model for the South Pool with the Application. The simulation model was based on a geological model built in Petrel. The cell dimensions and petrophysical properties were upscaled from 50m x 50m to approximately 100m x 100m. This resulted in the simulation model having 26 x 83 x 240 cells for a total of 517,920 cells.

As noted above, the South Pool simulation model submitted by the Proponent only contained predictive cases for the proposed Terrace Block infill producer and gas injector. The model contained the proposed locations for the Central Block infill wells and gas injector but no predictive cases involving these wells were provided.

The model has a deterministic STOOIP estimate of 92.9 MMm^3 (584.3 MMbbls) compared to the P50 probabilistic estimate of 86.5 MMm^3 (544.1 MMbbls). The model predicts an incremental recoverable oil of 0.72 MMm^3 (4.5 MMbbls) in the Terrace Block from the wells proposed in the Application.

Staff's review of the South Pool simulation model found that the model is sufficient in the context of this Application.

4.5.4.5 South Pool Incremental Production Performance

The Application contains production profiles for the South Pool incremental oil, water and gas production rates from the WHP. The Proponent assigned the incremental resources from the WHP by utilizing both deterministic and probabilistic evaluation methods. Simulation modelling was used to predict the incremental recovery from the Terrace Block while probabilistic methodology was used to determine the incremental recovery from the Central Block. This probabilistic work was based on existing analogous infill wells in the South Pool. The resulting production forecasts for the Central and Terrace blocks were then incorporated into a full-field integrated production model which takes into account facility constraints and downtime for anticipated facility turnarounds.

The predicted profiles for South Pool incremental oil, water and gas production are illustrated in Figure 4.27, 4.28 and 4.29, respectively.

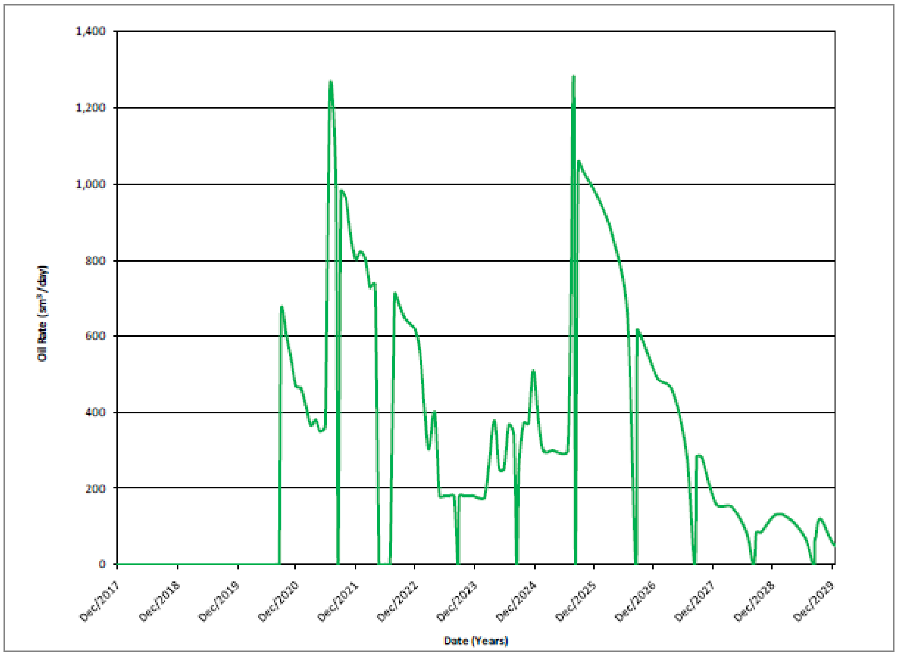

Figure 4.27: Predicted South Pool incremental oil production profile (From Husky, 2014).

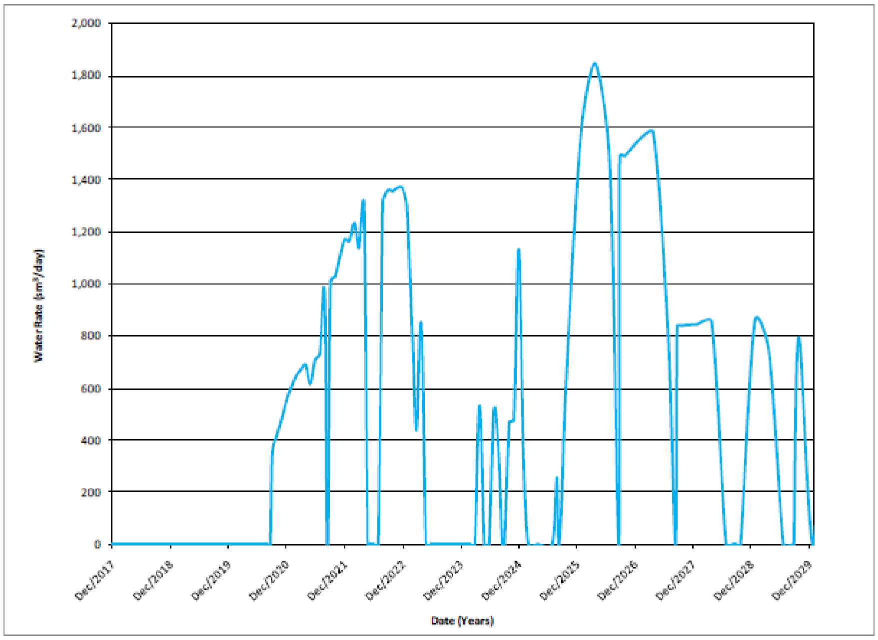

Figure 4.28: Predicted South Pool incremental water production profile (From Husky, 2014).

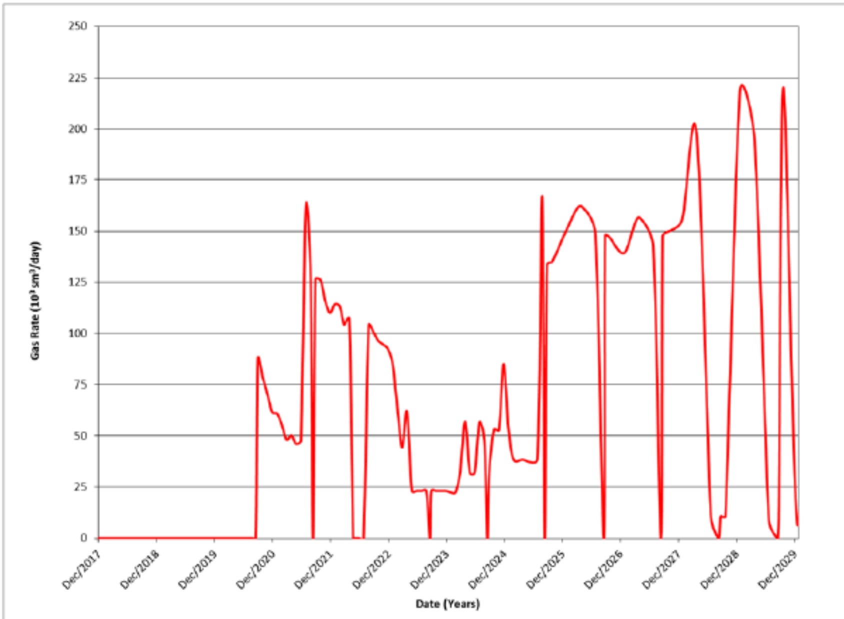

Figure 4.29: Predicted South Pool incremental gas production profile (From Husky, 2014).

4.5.5 Well Scheduling

As the West Pool oil resources are the primary driver behind the WHP, the well scheduling approach for the project is based on the phases of development for the West Pool. The Application indicates that West Pool wells with the lowest geological risk, generally located in the southern O-28Y region, will be drilled at the start of the project. Then drilling will incrementally step out from south to north in the pool. Drilling the wells in this manner will provide the Proponent with further insight into facies distributions, productivity of the parasequences and the lateral extent of the gas cap, because well locations will intersect more distal facies in the western and northern parts of the pool.

As the Proponent obtains further information on the geological trends, the well placement strategy for the West Pool will be optimized. In order to allow sufficient time for optimization work to occur, the WHP drill schedule includes periods of time for drilling wells in the other pools proposed for development. The Application indicates that the order of development for the other pools is driven by the remaining recoverable resource and well count for the respective pools.

The well schedule provided in the Application can be seen in Table 4.10. **Staff finds the Proponent's well scheduling strategy and planned drill schedule to be appropriate.**

Table 4.10: Proposed WHP drill schedule (From Husky, 2014).

Count	Field / Pool	Well Name	Well Type	On-Line Date
1	West	PRD7B	Oil	Nov,2016
2	Cuttings	Cuttings_1	Cuttings	Jan,2017
3	West	PRD6B	Oil	Apr,2017
4	West	INJ9B	Water Injector	Jun,2017
5	West	PRD10C	Oil	Sep,2017
6	West	INJ4A	Water Injector	Nov,2017
7	BLK 2&5	2P1	Oil	Feb,2018
8	BLK 2&5	5W1	Water Injector	May,2018
9	West	PRD5C	Oil	Jul,2018
10	West	INJ6A	Water Injector	Oct,2018
11	BLK 2&5	5P1	Oil	Jan,2019
12	West	PFB3HP2	Oil	Mar,2019
13	West	PFB1HI2	Water Injector	Jun,2019
14	South Avalon (SDC)	SAP3	Oil	Aug,2019
15	South Avalon (SDC)	SAPGI2	Gas Injector	Nov,2019
16	West	PFB1HP1	Oil	Jan,2020
17	West	PFB3HI1	Water Injector	Apr,2020
18	South Avalon (CDC)	SAP2	Oil	Jun,2020
19	West	PRD6C	Oil	Sep,2020
20	West	INJ8A	Water Injector	Nov,2020
21	Cuttings 2	Cuttings_2	Cuttings	Jan,2021
22	West	PRD5D	Oil	Apr,2021
23	West	INJ6B	Water Injector	Jul,2021
24	West	PRD3D	Oil	Sep,2021
25	West	INJ10D	Water Injector	Dec,2021
26	North Avalon	NAOP1	Oil	Mar,2022
27	North Avalon	NAOW10	Water Injector	Jun,2022
28	West	PFB5HP2	Oil	Aug,2022
29	West	INJ2B	Water	Nov,2022
30	West	B3UHZP1	Oil	Jan,2023
31	West	PFB3HI2	Water Injector	Apr,2023
32	South Avalon (CDC)	SAGI1	Gas Injector	Jun,2023
33	West	PRD11B	Oil	Sep,2023
34	West	INJ11A	Water Injector	Nov,2023
35	West	PFB2HP1	Oil	Feb,2024
36	West	PFB2HI1	Water Injector	May,2024
37	South Avalon (CDC)	SAP1	Oil	Jul,2024
38	West	PFB5HI1	Water Injector	Oct,2024

4.5.6 Full-Field Performance

Production from the South Pool, the West Pool pilot scheme and the North Amethyst Field is currently processed through the facilities on the *SeaRose FPSO*. As the WHP will not contain any processing facilities, the additional produced fluids from the proposed development will be processed with the existing infrastructure on the FPSO. In order to ensure that the processing facilities are capable of handling the increased production volumes, an assessment was conducted to ensure the predicted full-field volumes were within the production and injection capabilities of the FPSO. The production and injection constraints used for this assessment are as follows:

- Total Liquids – 33,000 m^3/day (208,000 bbls/day)
- Oil – 22,300 m^3/day (140,000 bbls/day)
- Total Water Injection – 44,000 m^3/day (277,000 bbls/day)
- Water Injection per excavated drill centre – 30,000 m^3/day (189,000 bbls/day)
- Produced Water – 28,000 m^3/day (176,000 bbls/day)
- Gas Compression – 4.2 MMm^3/day (148 MMscf/day)
- Lift Gas – 1.6 MMm^3/day (56 MMscf/day)
- Lift Gas per excavated drill centre – 1.19 MMm^3/day (42 MMscf/day)

The Proponent used an integrated production model to generate profiles for full-field oil production, produced water, water injection, liquid production, gas production, gas lift and gas handling. This was achieved by inputting the well schedule and individual pool forecast and simulation results into the integrated production model. Downtime for annual turnarounds and forecasted *SeaRose FPSO* off-station programs was also included. The resulting profiles were included in the Application and are shown in Figures 4.30 to 4.37. It is notable that the Proponent has extended field life to 2030 for the full-field production profiles. Production to 2030 would extend field life five years beyond the original 20-year design life of the FPSO. **Further work will be required by the Proponent to assess feasibility and impacts of extending the field life beyond 2025.**

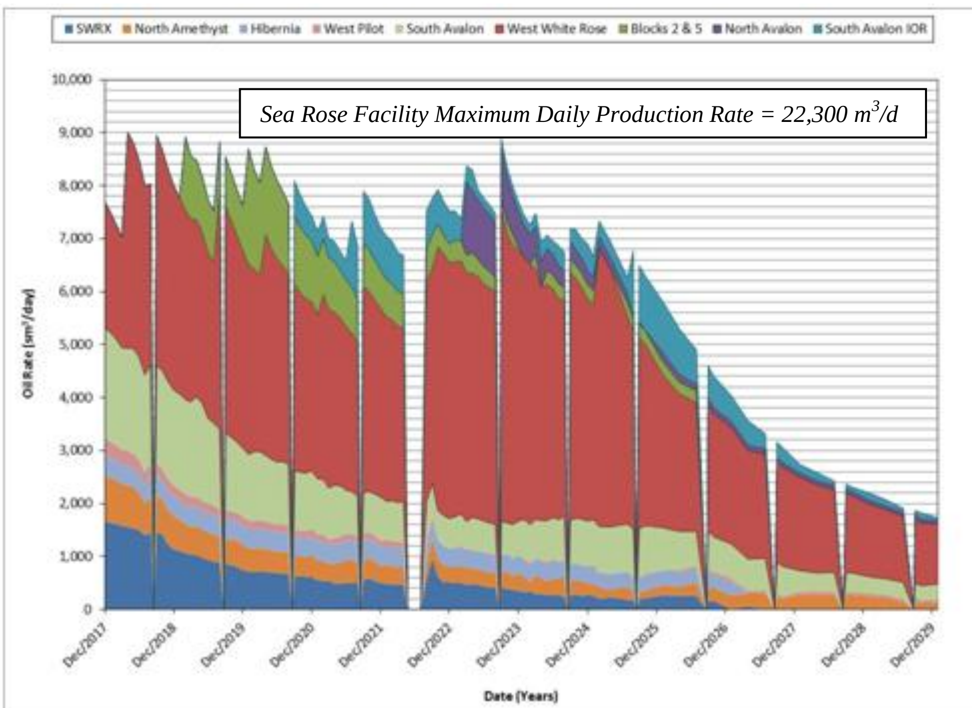

Figure 4.30: Full-field oil production profile (From Husky, 2014).

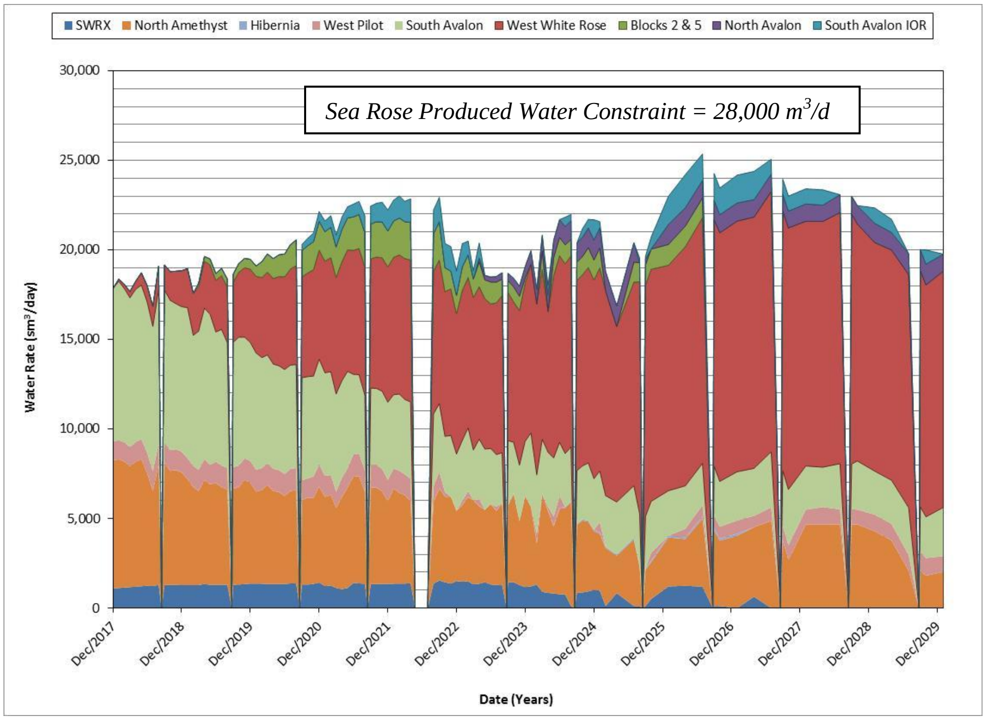

Figure 4.31: Full-field water production profile (From Husky, 2014).

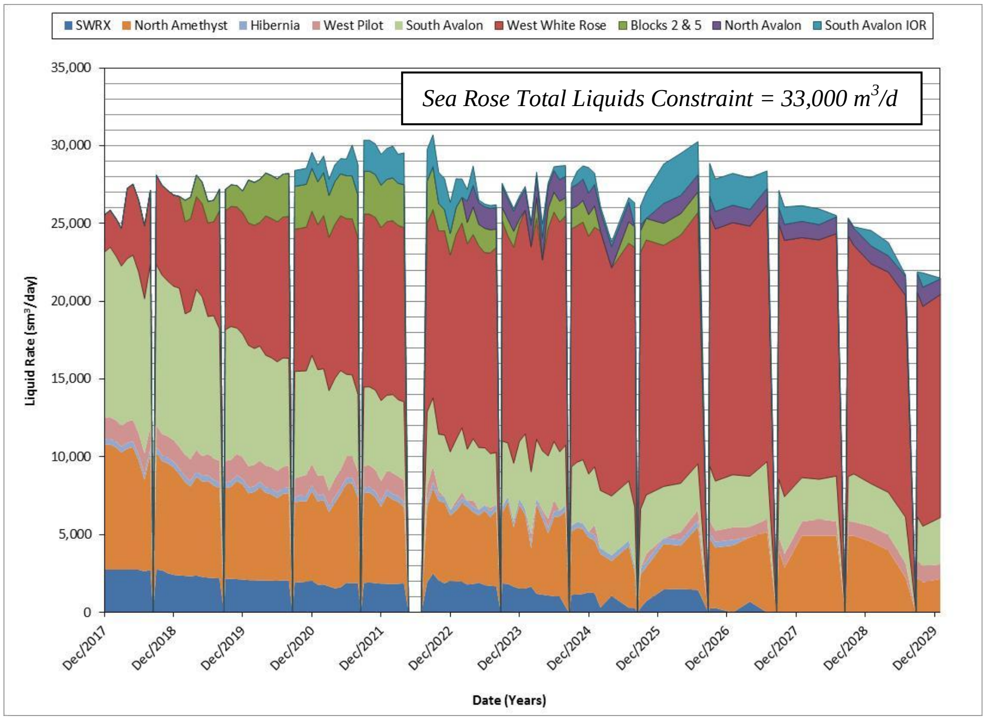

Figure 4.32: Full-field total liquid production profile (From Husky, 2014).

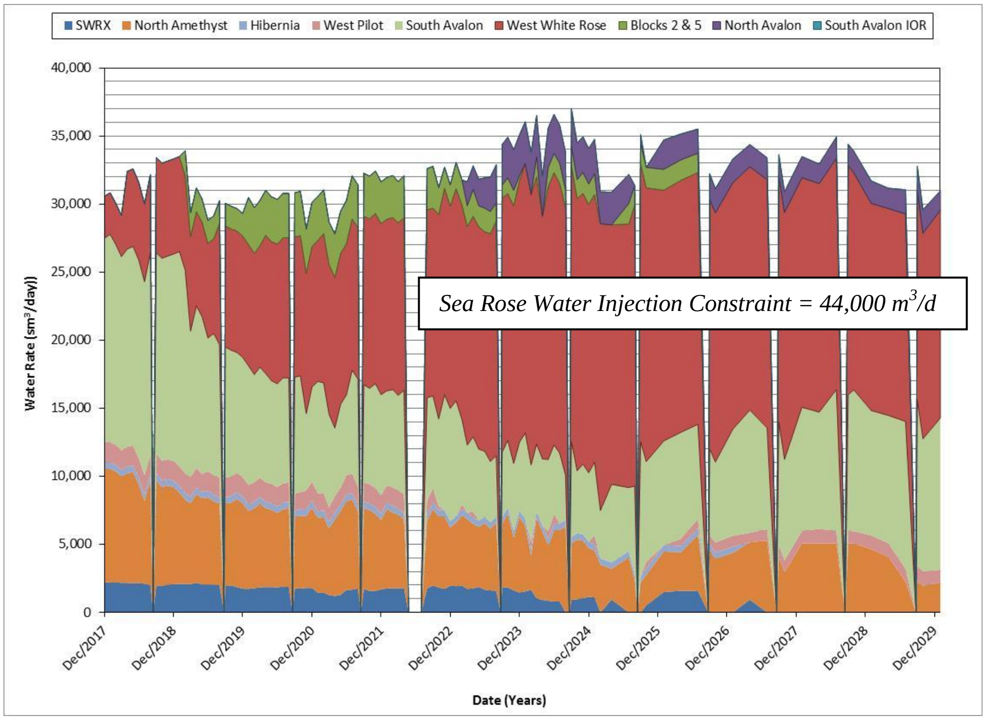

Figure 4.33: Full-field water injection profile (From Husky, 2014).

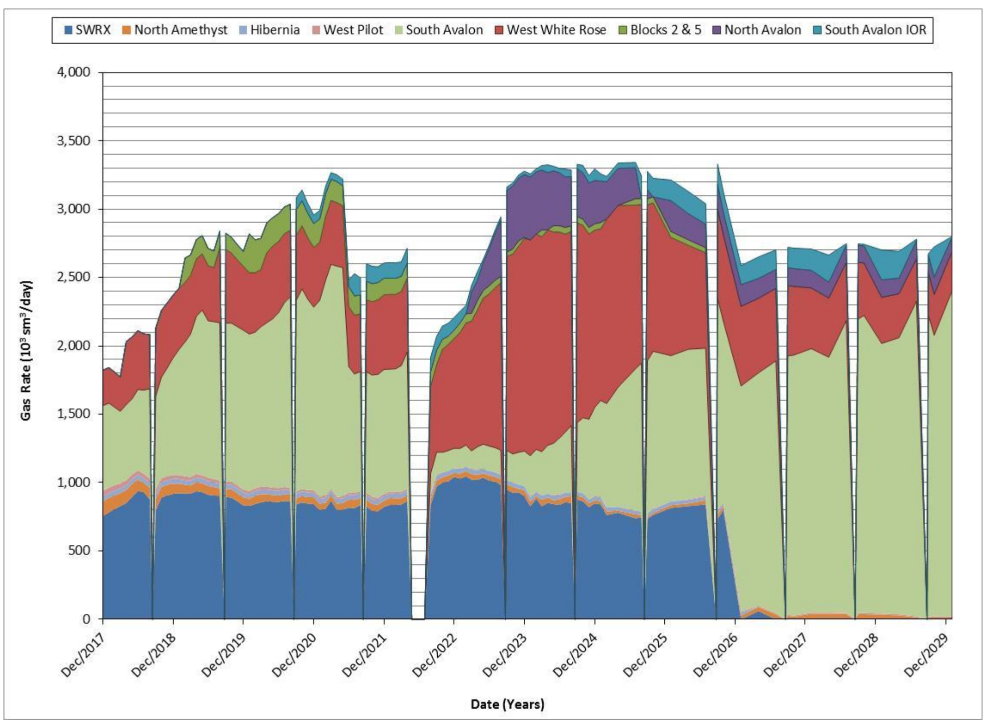

Figure 4.34: Full-field gas production profile (From Husky, 2014).

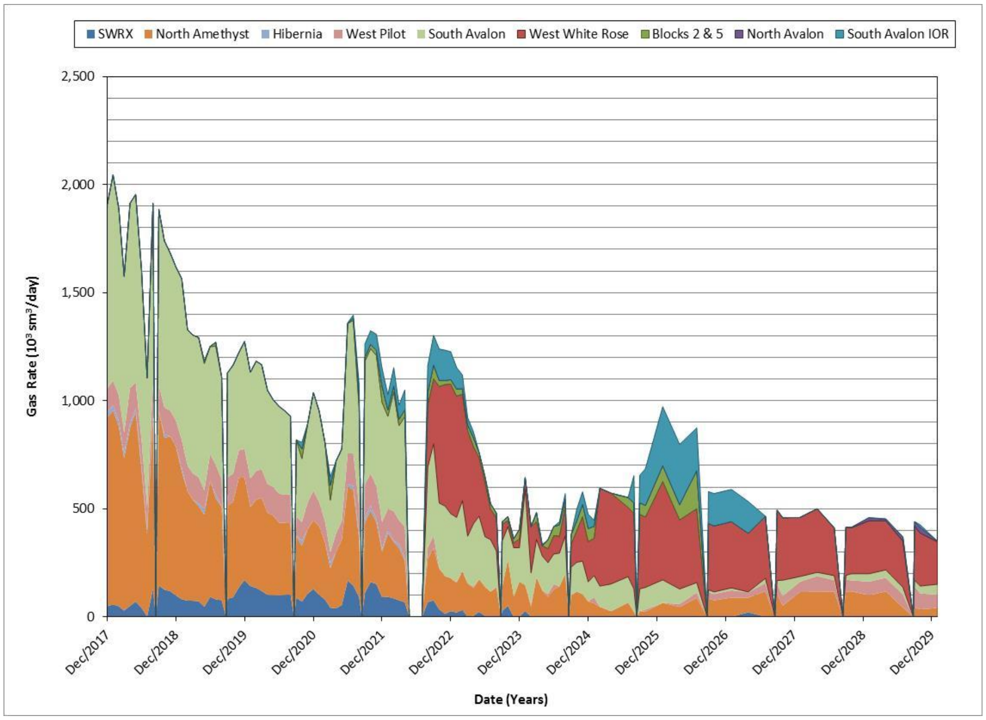

Figure 4.35: Full-field gas lift profile (From Husky, 2014).

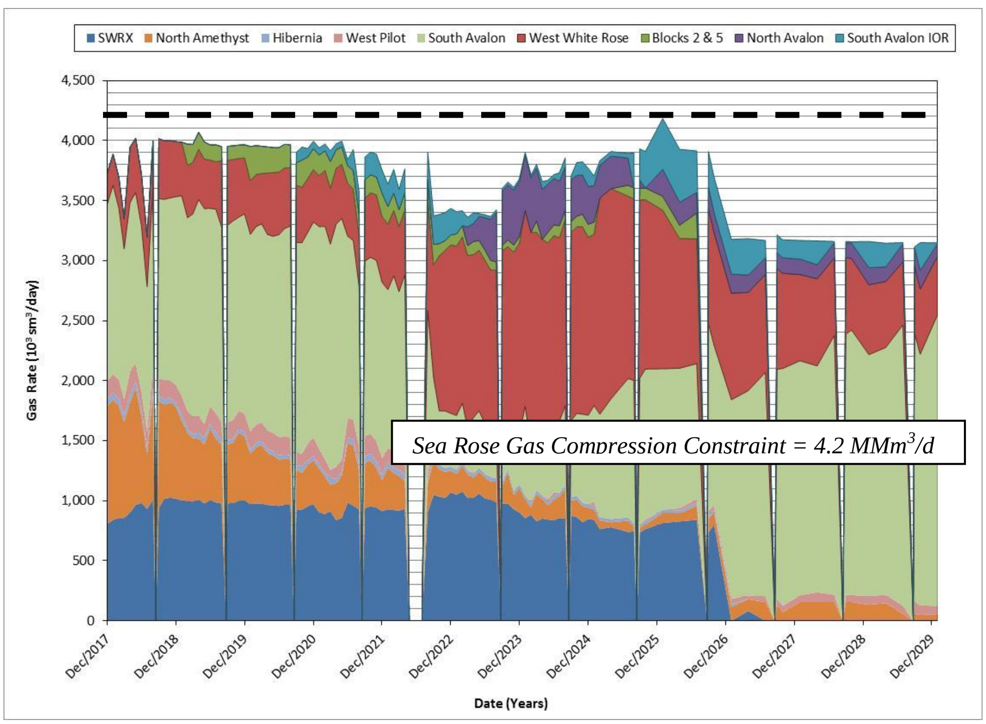

Figure 4.36: Full-field gas handling profile (From Husky, 2014).

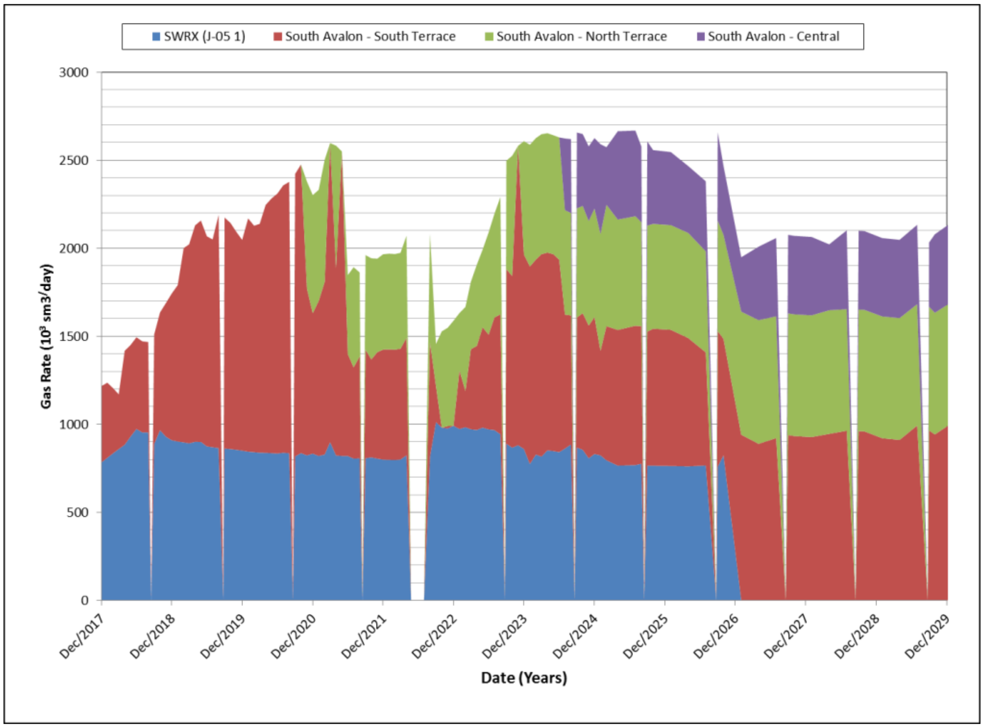

Figure 4.37: Full-field gas injection profile (From Husky, 2014).

Staff reviewed the full-field profiles to determine if there was any cause for concern regarding the *SeaRose FPSO* facility handling capabilities. Considering the facility constraints listed above, no significant issues with fluid handling were noted. As can be seen in Figure 4.36, there is a brief period in 2026 where the gas handling requirement approaches the *SeaRose FPSO* gas compression capacity (4.2 MMm^3/day) but this period is very brief. Furthermore, the Proponent will have the ability to temporarily decrease production or gas-lift volumes should any short-term issues arise. The use of ESPs on the WHP will provide the Proponent with another means of artificial lift should any temporary cut back on gas lift volumes be necessary.

4.5.7 Reservoir Management Plan

4.5.7.1 Displacement Strategy

The displacement strategy for all pools to be developed from the WHP includes secondary recovery by water flood. This may be augmented with gas injection, WAG injection, or partial-pressure support if deemed appropriate. The WHP will have the ability to change the flood mechanism from water flood to gas flood or WAG.

A voidage replacement ratio between 1.0 and 1.2 will be targeted for all pools during the operational phase. This is consistent with the voidage replacement ratio target for the existing developments and is found by staff to be reasonable.

4.5.7.2 Injection fluids

Gas lift and gas injection will be supplied to the WHP from the dry gas processed through the *SeaRose FPSO*. The gas has a water content of 24 kg/million Sm^3 and a water dew point of approximately -18°C at 40 MPa. Table 4.11 summarizes the composition of the gas that will be available for injection.

Table 4.11: Injection gas composition.

Gas Component	Mole Fraction		Specific Components	Mole Fraction
CO	0.0001			
H_2	Trace		neo-Hexane (C_6)	0.00000
He	0.0001		n-Hexane (C_6)	0.00084
O_2	0.0028		Methylcyclopentane (C_7)	0.00043
N_2	0.0135		Benzene (C_7)	0.00023
CO_2	0.0208		Cyclohexane (C_7)	0.00035
H_2S	0.0000		2,2,4-Trimethylpentane (C_8)	0.00000
C_1	0.8509		Methylcyclohexane (C_8)	0.00019
C_2	0.0554		Toluene (C_8)	0.00000
C_3	0.0318		Ethylbenzene (C_9)	Trace
iC_4	0.0045		m&p-Xylene (C_9)	0.00000
nC_4	0.0106		o-Xylene (C_9)	Trace
iC_5	0.0025		1,2,4-Trimethylbenzene (C_{10})	0.00000
nC_5	0.0031			
C_6	0.0021		**Plus Components**	
C_7	0.0011		C_7^+	0.00180
C_8	0.0007		C_{12}^+	0.00000
C_9	Trace		C_{15}^+	0.00000
C_{10}^+	0.0000			
TOTAL	**1.0000**			
Source: Maxxam report for Extended Gas Analysis of High Pressure Compressor Suction Scrubber, Lab No: B104883:Z50827, January 5, 2011				

Currently, seawater is treated and injected from the *SeaRose FPSO*. Treatment includes de-aeration with continuous oxygen scavenger injection and weekly biocide dosing. Treated injection water from the *SeaRose FPSO* will be used by the WHP. Table 4.12 summarizes the injection water density and composition.

Table 4.12: Injected seawater analysis.

Density	kg/m^3	1,024
Chemical Component		
Na	mg/l	9,772
K	mg/l	351
Ca	mg/l	438
Mg	mg/l	1,167
Cl	mg/l	17,498
HCO_3	mg/l	128
SO_4	mg/l	1,922
Reference: White Rose DA Volume 2 – 01/2001		

4.5.7.3 Gas Utilization

Produced gas from WREP will be re-injected through existing gas injection infrastructure within the White Rose region. Gas will be used primarily for further oil recovery through gas flood. The total gas produced over the life of the field is estimated at 13.1 billion Sm^3. This cumulative produced gas represents gas produced as a result of solution gas and gas cap gas, as well as the breakthrough of injection gas from gas flood.

Accounting for fuel gas, the gas to be injected over the field life is estimated to be 10.1 billion Sm^3. A portion of this represents gas that is recycled through the reservoir and is therefore not considered net gas that will require handling. The portion of the injected gas volume to be handled is approximately 4.95 billion Sm^3 between January 1, 2014 and 2030.

Based on produced, injected and fuel gas, staff reviewed the Proponent's estimates for gas flaring and determined that there is no net increase to flaring by the addition of the WREP. The flaring estimates are reasonable compared to historical data for the White Rose Field.

Dehydrated and compressed gas will be supplied to the WHP from the *SeaRose FPSO* gas compression/injection system. The compressed gas from the FPSO will be transported through the Northern Drill Centre (NDC) to the WHP via a gas injection flowline installed in 2013 to provide gas injection capability to the Southern Extension Drill Centre (Decision 2013.04). As part of the WHP subsea campaign, a new subsea gas flowline will be teed into this existing gas injection flowline to provide the WHP with a supply for gas flood, gas lift and fuel gas.

Staff reviewed the predictions for fuel gas and gas lift for the WREP and existing developments and found these to be reasonable.

4.5.7.4 Cuttings Re-injection

The Application proposes drilling of two wells for reinjection of drill cuttings.

Based on the *Newfoundland Offshore Drilling and Production Regulations* disposal of oiled drill cuttings requires approval from the Chief Conservation Officer (CCO). Each Operator that plans the use of synthetic-based mud (SBM) or enhanced mineral oil-based mud in development drilling should, as part of its development application, examine and report upon the technical and economic feasibility of re-injecting the associated drill solids into subsurface formations at the drill site(s). Permissible discharge concentrations for Operators experiencing periods of unanticipated malfunction during re-injection of drill solids are evaluated on a case-by-case basis by the CCO.

The Proponent must address the feasibility of re-injecting large volumes of cuttings into a suitable formation, and describe how production accounting will be impacted and managed. The formation for injection must be identified and reservoir simulations must be conducted to investigate the reservoir impact of cuttings injection. **A report containing these details and results of simulation will be required at least six months prior to submission of any Application to Drill a Well (ADW) for a cuttings re-injection well.**

In the review of an ADW for a well for the re-injection of cuttings, special attention will be paid to the following information:

- A schematic of the well outlining the following:
  - Casing details (setting depth, top of cement estimate and the basis for the top of cement estimate) for strings which will be included in cutting re-injection plan; and
  - Details of formation tops over the proposed injection interval. That is, the formations that will be exposed to pressure during injection operations.

- A brief description of the Operator's plans for the well operations which include confirmation of the following:

- Anticipated fracture gradient and pumping pressures;
- A summary of the injection test previously conducted at well (e.g., pump rate, pump pressure, injection fluid density, flush fluid density and shut-in pressure). This should include a brief description of the operation and a summary of the results, indicating if they were as anticipated;
- The formation into which the annular injection is expected to occur; and
- Verification that the well tubulars are adequate for the anticipated injection operating conditions.

Once the well has been approved for cuttings re-injection, reports of each injection are required to be submitted to the C-NLOPB. All cuttings re-injection equipment is required to meet relevant offshore standards and requires the approval of a certifying authority. In addition, the Applicant should address all safety concerns in terms of equipment, procedures and personnel competency. Staff recommends that the Board's approval include the following condition:

> **Condition 1: That prior to drilling of any cuttings re-injection well, the Proponent must provide a report suitable to the Board describing the feasibility of injection, the impact on reservoir management and the impact on production accounting. The report must be submitted at least six months prior to ADW submission.**

4.5.7.5 Reservoir Surveillance

Reservoir surveillance will be conducted with the information submitted via daily production reports and monthly S-Reports submitted via the *Monthly Production Reporting for Producing Fields* guideline. All meters used for reservoir surveillance will be defined in the approved Flow System Application.

4.5.7.6 Data Acquisition

The Application indicates that data acquisition for the WREP development will follow the Board's *Data Acquisition and Reporting Guidelines*. More detailed plans for data acquisition will be included in ADWs for individual wells.

Board staff notes that the area proposed for development will fall under the Proponent's *"White Rose Complex" Development Field Data Acquisition Program*. The current edition of the program, submitted to the Board in 2008, will remain in effect until 2015. Staff expects that the next revision of the program will address specific data acquisition requirements for the WREP area. The revised Field Data Acquisition Program should be approved prior to commencement of any drilling activities from the WHP.

4.5.7.7 Artificial Lift

Gas lift is the only artificial lift mechanism that has been used in the White Rose Asset to date, and it has proven to be effective. The Application indicates that gas lift will remain the primary artificial lift mechanism for the pools to be developed from the WHP; however, due to the increased technical functionality afforded from having dry tree access on the WHP, the Proponent plans to use electronic submersible pumps (ESPs) as a secondary gas lift mechanism for the West Pool, and possibly for other pools developed from the WHP.

The use of ESP technology will enable the Proponent to increase well drawdown. This will allow the acceleration of production from these wells and could lead to increased oil recovery in some cases.

ESPs have yet to be used in the Canada-Newfoundland and Labrador offshore area, but they have been used extensively in the oil industry worldwide both onshore and offshore. An important factor when using ESPs is the run life that they achieve, which industry experience shows is expected to be from two to five years. As the WHP will allow dry tree access, it will be possible to perform workovers to pull failed pumps and replace them.

Not all wells are ideal candidates for ESPs, and for this reason the Proponent will only use them in wells which meet specific criteria. For instance, ESPs will not be used for any wells in proximity of a gas cap, as the GOR from these wells eventually rises. ESPs are known to not perform well when gas production is high.

The Proponent is still reviewing the use of ESPs under the various expected operating conditions, so individual wells have not yet been selected. The Proponent's use of ESPs will be evaluated on a well-by-well basis and will evolve as information is obtained on ESP performance and the operating conditions of the reservoir. **Staff concurs with the Proponent's plans for possible ESP use as outlined in the Application and expects their use in individual wells to be addressed through the Approval to Drill a Well (ADW) process. Further details on ESP use and operation are expected in the Operations Authorization (OA) for the WHP.**

4.5.7.8 Well Stimulation

As detailed above, the West Pool is a structurally complex, heavily faulted and compartmentalized reservoir. Information obtained from the pilot scheme has provided the Proponent with a better understanding of the horizontal and vertical barriers/baffles and connectivity of the reservoir. The pilot scheme results have demonstrated a low vertical to horizontal permeability (k_v/k_h) ratio in the reservoir and across the major fault (vertical) boundaries. Toward more distal depositional environments in the north, the probability of lower k_v/k_h and less conductive faults is expected to increase as the net to gross decreases. In addition, the pilot scheme has also confirmed the lower reservoir quality and productivity of the upper parasequences.

Due to the challenges presented by the West Pool, the Proponent has evaluated a variety of well stimulation methods including near wellbore acidizing and hydraulic fracturing. The goal of these stimulation techniques would be to improve well productivity indices, increase initial oil production rates, accelerate production and increase recovery. This analysis of well stimulation methods has led to identification of a number of wells as candidates for hydraulic fracturing in the base development scenario for the West Pool. Certain wells would not benefit from hydraulic fracturing due to proximity to the gas cap or the oil-water contact, so these wells would not be candidates for this type of stimulation. The Application indicates the Proponent will perform an assessment of whether or not a well is suitable for hydraulic fracturing on a well-by-well basis.

Hydraulic fracturing will provide a number of benefits that will help to increase recovery from the wells in which it is used. As most of the West Pool wells will cross multiple fault blocks, hydraulic fracturing will help to decrease fault offset uncertainty with the ability to grow the fractures vertically. It is envisioned that each fault block would contain a vertical fracture to provide vertical coverage of reservoir contact to the wellbore, access stranded productive sands and cross vertical barriers to flow. The use of hydraulic fracturing will also help to reduce the risks of well placement or drilling trajectory uncertainty. Another key benefit from the use hydraulic fracturing is the production acceleration it will provide to help ensure production of West Pool oil reserves is maximized prior to the end of field life.

Hydraulic fracturing technology for conventional resources has yet to be used in the Canada-Newfoundland and Labrador offshore area, but it has been used extensively in the oil industry worldwide both onshore and offshore. Staff believes the use of hydraulic fracturing to accelerate production, increase recovery and reduce risk in the West Pool to be reasonable and appropriate from a resource management standpoint.

Staff concurs with the Proponent's plans for well stimulation in the West Pool as outlined in the Application. Board staff expects the Proponent to provide details through the ADW process of individual well hydraulic fracturing designs and suitability of wells for this technology. Further details on any well stimulation plans are expected in the OA for the WHP.

4.5.7.9 Enhanced Oil Recovery

While the Application proposes secondary recovery by water flooding for the West Pool and other pools to developed from the WHP, it also indicates that this mechanism could be augmented by gas injection, WAG or other enhanced oil recovery methods if found to be beneficial to oil recovery. The Proponent has performed studies on enhanced oil recovery schemes for the West Pool and other pools in the White Rose Asset but, with the exception gas flooding in the northern Terrace Block of the South Pool, did not provide simulation modelling or other forms of technical analysis in support of these studies with the Application. Staff is not opposed to the Proponent implementing these schemes, as the practice of routinely assessing EOR schemes is consistent with the requirements of the *Newfoundland Offshore Petroleum Drilling and Production Regulations*. **However, before the Proponent may proceed with gas or WAG injection from the WHP, simulation modelling or some other form of technical analysis that shows there will be no detriment to oil recovery must be provided to the C-NLOPB.** The Proponent has already received approval to augment the water flood in the southern Terrace of the South Pool with gas injection (Decision 2013.04). A producer and gas injector in this area are both scheduled to come online in 2015. This will provide a large quantity of production data from a gas flood scheme, and this data could be used as the basis for implementing such a scheme in the West Pool and other areas in the future. Staff believes the Proponent should be allowed to proceed with these proposed EOR schemes if they will lead to an increase in ultimate oil recovery. Staff recommends the following be a condition of the Board's approval:

> **Condition 2: That prior to initiating a gas flood or WAG scheme in the West Pool or any other pool to be developed from the WHP, the Proponent must provide simulation modelling or some other form of technical analysis which demonstrates that such a scheme will not be detrimental to oil recovery.**

4.5.7.10 Conclusion of Reservoir Management Plan Analysis

The Application is consistent with the Proponent's current Resource Management Plan for White Rose Field, and has suggested additional enhancements such as cuttings re-injection, ESPs, well stimulation and enhanced oil recovery. Staff concurs with these proposed changes, provided that all activities adhere to the relevant requirements of the OA, ADWs, and associated conditions.

4.6 Production System and Production Facilities' Capabilities

4.6.1 Selection of Production System

The Proponent undertook a review and selection process of possible development concepts for the White Rose Extension Project. A range of input parameters was used to assist the concept selection process, including but not limited to, facility costs and production profile.

Two potential concepts were analyzed:

1. Subsea wells tied back through a subsea drill centre in conjunction with the *SeaRose FPSO* and existing White Rose Field infrastructure; and
2. WHP in conjunction with the *SeaRose FPSO* and existing White Rose Field infrastructure.

The Proponent evaluated these two modes of development, including development drilling options, and the preferred concept is to develop the WHP (Figure 4.38).

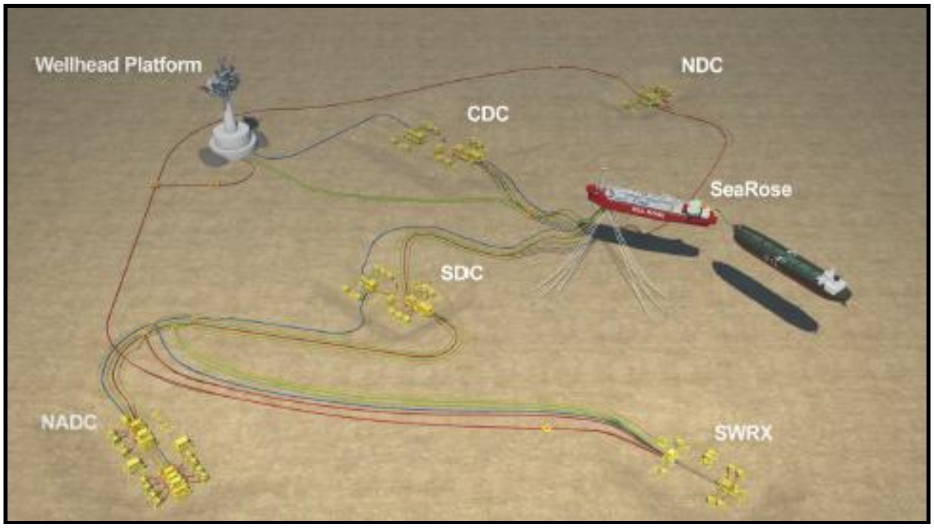

Figure 4.38: Schematic diagram of WHP preliminary development layout, shown connected to existing infrastructure in White Rose Field (From Husky, 2014).

The Proponent outlined the following key factors that contributed to selection of the WHP option:

- Reduced drilling and completion costs
- Reduced drilling costs on WHP facilitated higher well count
- Increased functionality on WHP provided more drilling options in highly complex reservoirs
- Ability to develop smaller pools which increases ultimate recovery
- Increased ultimate recovery and production acceleration from the use of well stimulation, artificial lift and other technological capabilities afforded by dry tree access

From a resource management perspective, Board staff concurs with the Proponent's decision that the WHP option is the preferred method, and it is technically feasible. According to the Application, the WHP will have the capacity to handle the predicted life-of-field production stream for 25+ years.

4.6.2 Design of Production System

The Proponent undertook an extensive process to review the design criteria for the project. A range of input parameters was used to assist the design of the WHP. In particular, the Proponent used the following criteria:

- Physical environmental criteria
    - Wind
    - Air temperature
    - Waves
    - Sea temperature
    - Current
    - Sea ice
    - Icebergs
- Design loads
- Functional criteria
    - Design life
    - Flow rate
    - Capacities
- Geotechnical criteria
    - Seismic hazard potential

- Soil characteristics
- Iceberg scour
- Shallow gas considerations

The main function of the WHP is to provide 'dry tree' drilling and completions. All reservoir fluids produced to the WHP will be transported to the *SeaRose FPSO* for processing. There will be no oil storage on the WHP. The Application states that the oil-handling capacity of *the SeaRose FPSO* is anticipated to accommodate the requirements of the WHP, therefore no upgrades are needed. The oil-handling capacity is 22,300 Sm^3/d.

Some provisions for future expansion will be included in the WHP design. The design includes risers for oil production, water injection and gas lift. Along with this, Husky may also develop up to two additional subsea drill centres in the White Rose region. The WHP will have the capability to tie back one new drill centre. Tie-back of a second drill centre would be through an existing drill centre or directly to the FPSO. Subsea flowlines will be used to interconnect the WHP and the FPSO for oil production, water injection and gas injection. According to the Application, the WHP can accommodate 20 well slots using conductor-sharing wellhead technology in some wells, allowing two wells to be drilled per slot for a total of 40 wells.

4.6.3 Design Life

According to the Application, the WHP facility will have a design life of 25 years and it will be designed to accommodate production conditions throughout the life of the facility. The Proponent points out that although the design life of the WHP is 25 years, the current field life of the *SeaRose FPSO* is only until 2025. Future studies will be undertaken to determine the feasibility of extending the life of the FPSO beyond 2025. The Proponent will also study other options to continue operation of the WHP beyond 2025.

4.6.4 Flow Rate and Capacities

Table 4.13 summarizes the maximum design parameters for the WHP. The Application notes that these values will be refined during detail design.

Table 4.13: WHP production profile design parameters.

Fluid	Maximum Design Parameter
Daily Oil	7,800 m^3/d
Daily Water	17,000 m^3/d
Daily Liquid	22,000 m^3/d
Daily Total Gas (Produced + Lift)	2,500,000 Sm^3/d
Daily Gas Flood	1,650,000 Sm^3/d
Daily Gas Lift	1,450,000 Sm^3/d
Daily Water Injection	20,000 m^3/d

4.6.5 Production Test Separator and Fluid Sampling

The Application indicated that the Proponent will follow regulatory testing requirements. It also states that a test header may be required to accommodate well testing of future subsea tie-back wells if the temperature of fluids arriving at the WHP is insufficient to obtain good phase separation. Fluids collected from the WHP production wells will be routed to the production manifold. Half of the production wells will be connected on one side of a common production header with the remaining production wells connected to the other side. Any empty slots will be closed via blind flanges. If a well requires testing, it will be routed to the WHP test separator. Testing will use a three-phase test separator on the WHP. The tested fluids will be separated into three phases and measured through the associated flow meters. The tested streams will be recombined and added to either of the main production lines without gas compression and liquid pumping. This is because the test separator will operate at a higher pressure than the export flow lines. These flows will also be measured through multi-phase flow meters installed on the main production export lines.

The Proponent indicated that standard sampling points will be provided on gas and liquid lines to allow for collection of samples that can be tested in the on-site laboratory.

4.6.6 Gas Supply Systems

Dehydrated and compressed natural gas will be provided to the WHP from the SeaRose FPSO gas compression/injection system. The gas will be supplied via a single high-pressure gas flowline teed into an existing subsea flowline at a midline point between the North Drill Centre and SWRX Drill Centre. The gas will be used for gas lift, fuel gas and gas flooding. It is believed that the WHP demand for gas lift and platform fuel gas will be within the existing design capacity of 4.2 MSm^3/d. The Proponent has noted that a gas supply inlet heater is included in the WHP design for periods when it may be required to heat the full inlet gas stream above hydrate formation temperature.

Gas supplied for gas lift and injection will be run through a manifold that will also have the ability to operate using WAG. The Proponent has stated that the gas flood wells will have methanol injection points for preventing hydrate formation. The first region to be gas flooded from the WHP will be the South Pool. The Proponent has also indicated that a portion of the produced gas may be used for gas flood or WAG schemes in order to support oil production from other pools within the WREP.

The Application noted that all metering of gas volumes will be done in accordance with the C-NLOPB *Measurement Guidelines*.

4.6.7 Flare System

The flare system on the WHP is an integrated part of the pressure relief and safety system. The Application states that design of the flare relief system will be consistent with all applicable regulations and standards. The flare system includes the manifolds, piping, flowlines, knock-out drum including pumps and heaters, the flare stack and the flare tip. The system will be sized to accommodate all predicted WHP flare operational scenarios.

The separate liquids in the flare knock-out drum will be combined with WHP production fluids and transported to the *SeaRose FPSO* for further processing. The Proponent states that the WHP flare system will be designed such that the depressurization of the WHP topsides inventory can be managed by the WHP. The gas injection flowline connecting the FPSO and the WHP will be managed by the FPSO flare system. The Proponent anticipates that the FPSO flare system will be capable of handling any operational requirements as a result of the incorporation of the WHP into the system.

The proposed processing facilities and flare tip will be designed so that radiation levels for all flaring cases are below the limits specified by the regulations for the flare tip height at all access ways and at all work locations. Also, prevailing wind velocity and direction along with the location of other equipment will be taken into consideration.

It is noted that the flare gas system will be continuously purged with fuel gas and will be ignited by a pilot burner. The pilot fuel source will be fuel gas with a propane back up.

4.6.8 Produced Water System

The Proponent states that there will be no processing fluids on the WHP and therefore, produced water from WHP wells will be separated, treated and disposed on the *SeaRose FPSO*. The produced water design capacity on the

FPSO is 28,000 Sm^3/d. The Proponent believes that the produced water handling capacity on the FPSO will be sufficient and will not require any upgrades.

In the original Decision 2001.01, the Board stated in Condition 37 that produced water should be assessed so that it can be re-injected into subsurface formations **if this is technically feasible and economically reasonable**.

At the time of submission of the Application, the Proponent was still assessing this condition. The Proponent has provided information to Board staff, working towards resolution of this issue. The Proponent is expected to include the latest information, which includes the WREP, in their assessment of Condition 37.

4.6.9 Water Injection System

The Application indicates that water injection will continue to be the main mechanism of support for reservoir pressure in the White Rose Field. The *SeaRose FPSO* will provide treated water injection to the WHP via the Central Drill Centre water injection manifold. The FPSO water injection system operates at 44,000 Sm^3/d, at a maximum of 30 MPa. Gauge supply pressure will be sufficient to support the WHP and no upgrades will be required. The Proponent states that injection pressures up to 35 MPa may be required at the WHP to support the West Pool reservoir. Due to current FPSO capacities, high-pressure water injection pumps will be required on the WHP to meet the required injection pressure. Flow meters will measure the water volumes injected into each well.

4.6.10 Chemicals, Storage, Metering and Injection Systems

According to the Application, the WHP will have a stand-alone chemical injection, storage and metering system. A methanol injection system is proposed for the WHP for hydrate prevention and equalization of surface-controlled subsurface safety valves. Methanol injection will be required at cold start-up, as part of a planned shutdown, during upset conditions and when bringing on new wells. The largest usage is predicted before and after planned shutdowns as wells and flowlines may require methanol treatment to prevent hydrate formation.

The Application states that scale inhibitor will also be required for injection at the WHP. This injection will be through a chemical injection mandrill in the well completion. The WHP will have a hypochlorite generation skid to treat seawater inlets. The WHP will be designed to accommodate tie-in of future chemical injection equipment as required.

4.6.11 Power Generation

The Application states that power generation and distribution facilities on the WHP will be a stand-alone isolated system. The main power generation will be comprised of dual fuel (gas/diesel) turbine-driven generators. The Proponent states that it will employ the best available technology to minimize greenhouse gas emissions. Under normal operating conditions, the main power generators will supply all power requirements for the topsides equipment. All fuel gas will be supplied by the *SeaRose FPSO*.

The Proponent states that a diesel-driven emergency generator and distribution system will supply all emergency electrical loads in accordance with the relevant regulations.

4.6.12 Fluid Measurement, Sampling and Allocation

A Flow System Application (FSA), or an updated revision of the existing FSA, will need to be submitted by the Proponent and approved by the Board prior to first production from the WHP. The FSA must comply with the *Drilling and Production Regulations (Part VII – Measurements)* and *Measurement Under Drilling and Production Regulations*. Monthly Reporting must also be submitted in accordance with the *Monthly Production Reporting for Producing Fields* guideline.

4.7 Reserve Estimates

The Application presented the Proponent's probabilistic recoverable oil estimates for the pools to be developed from the WHP. Table 4.14 summarizes the Proponent's low, expected and high-case recoverable estimates for these regions.

Table 4.14: Proponent's recoverable oil volumes. Note: Probabilistic sum will not sum arithmetically.

Pool	Probabilistic Estimates					
	P90		P50		P10	
	MMbbls	MMm^3	MMbbls	MMm^3	MMbbls	MMm^3
West	**63.5**	**10.1**	**107.6**	**17.1**	**134.0**	**21.3**
West WHP incremental	49.1	7.8	93.1	14.8	118.9	18.9
North	**3.1**	**0.5**	**3.8**	**0.6**	**6.3**	**1.0**
Blocks 2 & 5	**6.3**	**1.0**	**9.4**	**1.5**	**17.0**	**2.7**
Block 2	3.8	0.6	6.3	1.0	11.3	1.8
Block 5	1.9	0.3	3.1	0.5	6.3	1.0
South Full Field	**195.6**	**31.1**	**241.5**	**38.4**	**298.8**	**47.5**
Terrace	105.0	16.7	134.0	21.3	170.5	27.1
Central	86	13.7	107.6	17.1	132.7	21.1
Pool	**Deterministic Estimates**					
	Low		Mid		High	
	MMbbls	MMm^3	MMbbls	MMm^3	MMbbls	MMm^3
South Existing Development	**206.3**	**32.8**	**217.6**	**34.6**	**239.6**	**38.1**
Terrace	112.0*	17.8*	117.0*	18.6*	130.8*	20.8*
Central	94.3*	15*	100.6*	16*	108.8*	17.3*
South WHP Incremental	**5.0***	**0.8***	**8.8***	**1.4***	**15.1***	**2.4***
Terrace	2.5*	0.4*	4.4*	0.7*	7.5*	1.2*
Central	2.5*	0.4*	4.4*	0.7*	7.5*	1.2*
*Indicates deterministic value.						

The Proponent's probabilistic reserve ranges took into account White Rose Asset production performance data, reservoir quality knowledge of the respective pools and the use of potential technologies permitted by the WHP and dry tree access. The West, North and South pool estimates are supported by deterministic reservoir simulation models that typically represent an approximate P50 probabilistic basis. The Application did not include a reservoir simulation model for Blocks 2 and 5.

Because the South Pool and a portion of the West Pool are currently producing through existing field infrastructure, the Proponent provided estimates of the incremental production from these pools through the WHP. The recoverable incremental volumes from the West Pool are probabilistic estimates, while the incremental recoverable volumes from the Terrace and Central blocks of the South Pool are deterministic (Table 4.14).

Taking into account the incremental recoverable from the currently producing pools and the additional recoverable from Blocks 2 and 5 and the North Pool, the Proponent indicates that a potential recoverable oil estimate of 18.3 MMm^3 (115.1 MMbbls) can be expected from the WHP.

The recoverable estimates presented in the Application are based on the assumption that the White Rose Asset produces to the year 2030, which is five years beyond the original 20-year design life of the *SeaRose FPSO*. The Proponent indicates the end date of 2030 for estimating recoverable reserves is not a statement of intent to operate to a specific date beyond the current design life of the White Rose Asset original infrastructure. Further work will be required to assess the feasibility and impacts of extending the field life out to 2030 or beyond. The Proponent will continue to monitor the condition and operating regimes for the *SeaRose FPSO* and existing subsea equipment and will evaluate the need for replacement as equipment approaches the design life.

Staff performed a detailed review of the Proponent's estimates of recoverable oil for each pool to be developed from the WHP. Staff also conducted a review of the available geophysical, geological and engineering information in order to perform an independent estimate of oil reserves and resources for these pools. Staff's recoverable oil estimates are presented in Table 4.15.

Table 4.15: C-NLOPB estimated recoverable oil reserves.

Pool	Deterministic Estimates					
	Downside		Best Estimate		Upside	
	MMbbls	MMm^3	MMbbls	MMm^3	MMbbls	MMm^3
West	**75.7**	**12.0**	**117.1**	**18.6**	**146.6**	**23.3**
North	**3.4**	**0.5**	**5.7**	**0.9**	**12.5**	**1.99**
Blocks 2 & 5	**8.3**	**1.32**	**12.9**	**2.1**	**19.3**	**3.1**
South	**214.8**	**34.2**	**246.2**	**39.1**	**278.5**	**44.3**

Staff's estimates of recoverable oil volumes are based on its independent geological models, its own simulation modelling work for the West and North pools and a variety of other reservoir engineering evaluation methods. These methods include decline curve analysis, historical production performance, consideration of infill drilling results and assessment of the potential enhanced oil recovery techniques being considered by the Proponent. Furthermore, staff's reserve assessment also considered the technological capabilities available to the Proponent from having dry tree access on the WHP, which will help to accelerate production and increase ultimate recovery. These technologies include the use of ESPs, hydraulic fracturing and other well stimulation methods and intervention capabilities such as water shut offs, which would not typically be available for a subsea development.

At this time, staff expects the earliest potential first oil date from the WHP to be late 2018. This will provide the Proponent with only eleven years to deplete the pools proposed for development from the WHP assuming the field produces out to 2030. For this reason, timely execution of the drilling schedule and production acceleration efforts will be key factors to ensuring the Proponent is able to achieve the predicted recoverable reserves and capture any upside potential. Developing these pools by using the WHP will help to mitigate these risks as the Proponent will be able to execute its drill schedule without facing the numerous delays that could be expected if the wells were drilled subsea from a semi-submersible drill rig. By using the drill rig on the WHP, the Proponent will be able to avoid drilling downtime caused by things such as weather, rig moves and long-duration shipyard visits, which are common for semi-submersible drill rigs in our offshore area. In addition, the WHP affords the Proponent dry tree access which will allow the Proponent to use technologies such as ESPs and hydraulic fracturing, which will help to accelerate production and ensure reserves are produced in a timely fashion. With dry tree access, the Proponent will also have the ability to perform well interventions such as water shut-offs or perforation additions that could also help to increase production from the WHP.

Overall, there is generally good agreement between staff's and the Proponent's recoverable oil estimates. Based on the current knowledge of the pools to be developed from the WHP, staff believes the Proponent's reserve estimates are reasonable.

4.8 Deferred Developments

4.8.1 White Rose Gas Resources

Section 14.0 of the Application includes a technical review of gas resources. It addressed potential gas development including both gas resources in the White Rose Field and the regional gas resource potential. The Proponent's in-place estimate of gas is 63.9 10^9 Sm^3 (Table 4.16), based on its most recent deterministic geological models and volumes of produced gas that have been re-injected for storage and conservation.

Table 4.16: Proponent's estimated WREP gas resources (From Husky, 2014).

Area	Free Gas (10^9 Sm^3)	Solution Gas (10^9 Sm^3)	Injected Gas (10^9 Sm^3)	Total Gas (10^9 Sm^3)
South Pool	12.5	8.5	-	21.0
Blocks 2 and 5	0.2	0.8	-	1.0
North Pool	9.0	1.0	3.2	13.2
West Pool	11.6	8.0	0.4	20.0
Southern Extension Pool	6.7	2.0	-	8.7
Total	**40.0**	**20.3**	**3.6**	**63.9**

Staff also notes that the significant quantities of natural gas liquids (NGLs) are associated with the gas. Where practical, exploitation schemes need to be designed to ensure that recovery of these NGL resources is maximized. Further studies need to be undertaken to assess this potential prior to approving any plan to exploit the gas.

In the original White Rose Development (2001), it was the Proponent's view that in order for oil recoveries to be maximized reservoir pressures must be maintained, and smearing of the oil leg into the gas cap should be avoided. Therefore, depletion of the gas resource should not commence until exploitation of the oil resource is well advanced. The Proponent believed that drilling and depletion of the oil legs, along with gas conservation monitoring, would provide valuable information as to the reservoir quality and compartmentalization in the gas cap areas. The Board agreed with the Proponent's view that in order to maximize oil recoveries, reservoir pressure must be maintained and smearing of the oil leg into the gas cap, which could occur as a result of producing the gas cap, should be avoided. It was the Board's view that this potential also exists for the West and North pools. Typically, in such cases, oil production occurs first, with gas production following at a later stage of oil depletion or when there is sufficient information to determine that gas production will not adversely affect oil recovery. The current Application follows the original Decision 2001.1, continuing the proposed development of the oil resources of the West and North pools.

Staff believes that additional information is required before gas development can proceed and concurs with the Proponent that drilling and depletion of the oil legs, along with gas conservation monitoring, will provide valuable information about reservoir quality and compartmentalization in the gas cap areas. Also, the development wells will provide information to better assess White Rose gas resources.

In order to facilitate gas development, staff believes the Proponent must undertake timely delineation of the resource and development planning. With respect to the current Application, staff concurs with the proposed approach of using gas to aid in increasing oil recovery. For the oil accumulations, it is important that they be exploited with the current production infrastructure. For instance, the existing depletion plan includes gas injection into the gas cap in the southern portion of the South Pool Terrace from the SWRX Drill Centre, to increase oil recovery by moving unswept attic oil down into existing producers and a planned infill well. Furthermore, the Application proposes additional utilization of the gas resources for gas flooding in the northern portion of the Terrace and the Central Blocks of the South Pool.

In terms of regional development of gas resources on the Grand Banks, staff believes that the White Rose Asset will play a key role, since it contains a substantial proportion of the current discovered gas resources. Additional delineation drilling is needed to prove up these resources. Staff concurs with the Proponent and others that development of the gas resources will require basin-wide cooperation, as there are insufficient resources in any one field to justify development at this time. This will require that the availability of gas from all fields be analyzed.

In relation to facilities to accommodate gas production, it is staff's view that a dedicated facility will likely be required for substantive gas production from the White Rose Asset. However, the facilities proposed for oil development (FPSO, subsea wells and/or wellhead platform) should be considered in an overall plan to accommodate limited gas export. Development of gas resources could potentially extend the life of the existing production facilities and increase oil recovery, or indeed may require a separate production facility. The necessary information to assess the development potential will be acquired from additional seismic, development and delineation drilling, and production performance. It will take time to assemble, interpret and act on all the information.

Staff acknowledges the Proponent's efforts in the last five years to keep on top of existing and evolving gas development technologies. The Proponent has indicated that it is aware of the advances and limitations of technologies such as compressed natural gas, floating liquefied natural gas, pipelines and associated onshore liquefied natural gas terminal options. In order to ensure the Board can assess timely development of the gas resource, staff recommends that the following be a condition of the Board's approval:

> **Condition 3: That the Proponent submit to the Board, within three years following initiation of production from the White Rose wellhead platform:**
>
> - **An updated evaluation of the White Rose Asset gas resources along with a description of activities to be undertaken to evaluate the resource; and**
> - **A report on the advances and limitations of technologies such as compressed natural gas, floating liquefied natural gas, pipelines, associated onshore liquefied natural gas terminals and any other currently existing commercial offshore gas technologies and how these technologies relate to the gas resources of the White Rose Asset.**

4.8.2 Hibernia Formation

The Hibernia Formation is a deeper sandstone reservoir, and is the primary producing interval at Hibernia Field. Hydrocarbon production from the Hibernia Formation at the adjacent North Amethyst Field was approved by the Board in Decision 2013.06. Hydrocarbons have also been encountered in White Rose Field, in the E-09 and N-22 wells.

At the request of the Board, the Proponent addressed this oil accumulation in the document *White Rose Oilfield Development Application Supplemental Report*, March 2001. According to the Proponent, the Hibernia Formation was not included as a deferred development in the Application because data gathered to date indicate that it is unlikely to be economically viable for development.

The Proponent notes the following reasons:

- Current estimations of original oil-in-place ranging from 8 ^{to} 24 MMm^3 will likely not justify economic development as the net pay is relatively thin and spread over a relatively large area.
- The formation is considerably deeper than the BNA Formation (600+ m), and would require additional wells to be drilled for depletion.

- Reservoir permeabilities determined from drill stem test evaluations are very low (in the 10 mD range) and as a result, flow rates from the zone are also expected to be very low.

More detailed mapping and modelling of the formation will be carried out by the Proponent, and based on the results of the evaluations, a decision will be made as to whether or not it is reasonable to drill a delineation well.

The information provided by the Proponent and staff's own analyses indicate that the Hibernia Formation oil accumulation contains significant quantities of oil. Staff acknowledges that the oil accumulation is contained in low permeability reservoir with relatively low production rate, under 100 m^3/d, during drill stem testing. There is therefore significant uncertainty surrounding its development potential.

Staff acknowledges the work planned by the Proponent, and will require the results of the studies to be submitted to the Board. However, Board staff believes that additional data are required to assess the development potential of these oil resources and, where practical, the production facilities should provide for exploitation of the resources. The position of Hibernia Formation below the BNA reservoir presents an opportunity to drill selected deeper pilot holes sections within BNA development wells to evaluate the Hibernia Formation. **The Board should require a thorough assessment of the production potential of the Hibernia Formation oil accumulation prior to approving field abandonment.**

4.8.3 Eastern Shoals Formation

The Eastern Shoals Formation is another sandstone reservoir located stratigraphically below the BNA Formation that has tested hydrocarbons in three White Rose wells. The reservoir is generally too thin to be resolved seismically, and therefore the extent and quality of the reservoir is uncertain. The Proponent considers its development potential to be limited due to thinness of the sands and lack of well data. Therefore, staff considers the Eastern Shoals Formation to be a deferred development in the WREP at this time.

4.8.4 South Mara Member

The South Mara Member of the Banquereau Formation is a Tertiary sandstone unit, stratigraphically much higher than the BNA reservoir. The White Rose L-61 well tested gas and condensate in the South Mara Member. This resource has not been fully evaluated, and is considered a deferred development by Board staff.

4.8.5 Jurassic Sandstones

A sandstone reservoir of Jurassic age (stratigraphically much deeper than the BNA reservoir) tested gas in the White Rose E-09 well. Jurassic sandstones have not been fully mapped in the White Rose area due to limited well penetrations and poor seismic data quality at depth. There is a high degree of uncertainty about the size and extent of the resource; however, the Application notes that should development be deemed feasible, the Jurassic reservoir interval could be reached by drilling from the WHP. Staff considers hydrocarbons in Jurassic reservoirs to be a deferred development at White Rose Field.

4.8.6 Conclusion

Should the Proponent elect to proceed with development of any of the resources described above, a DPA will be required.

4.9 West White Rose Pilot Scheme

The West Pool pilot scheme (Decision 2010.01) has allowed the Proponent to reduce uncertainty and obtain a better understanding of the West Pool and its development feasibility. The primary objectives of the pilot scheme have been achieved. This has enabled optimization of the depletion plan for the pool and led to submission of the Application. This depletion plan, as outlined in the Application, calls for continued use of the pilot scheme producer and injector as development wells.

Because it has met its original objectives, resulting in the submission of a development plan, the West White Rose pilot scheme should now be considered complete. Staff therefore recommends that the pilot scheme cease and that the E-18 10 producer and E-18 11 injector be reclassified as development wells once the Application has been approved, allowing for continued production and injection from these wells. Should the Application not be approved, the pilot scheme will cease with no further production or injection from the E-18 10 producer and E-18 11 injector permitted until a new DPA for the West Pool is approved.

Reclassification of the pilot scheme wells to development wells will be based on the assumption that the Proponent is moving toward implementation of the approved exploitation scheme, as detailed in the Application. If the Proponent makes any of the following deviations from the approved exploitation scheme, the C-NLOPB will require submission of a new DPA:

1. Makes significant changes in the timing or nature of development of the pool or field.
2. Makes substantial modifications or additions/subtractions to existing facilities.
3. Initiates a reservoir depletion scheme that differs from the one detailed in the Application.

With regards to changes in timing of the development, the Board, in consultation with the Chief Conservation Officer, will evaluate at six-month intervals from the date of the Decision, whether the Proponent is moving toward timely execution of the project. If during such evaluation, the Board determines the commitments outlined in the Application are not being met, production and injection from the E-18 10 and E-18 11 wells shall cease. In such circumstances, no further production or injection from the West Pool shall be permitted until a new DPA for such activity has been approved.

Condition 4: That the Board, in consultation with the Chief Conservation Officer, will evaluate the commitments outlined in the Application at six-month intervals commencing from the date of the Decision. If during such evaluation the Board determines the commitments are not being met, production and injection from the E-18 10 and E-18 11 wells shall cease. In such circumstances, no further production or injection from the West Pool shall be permitted until a new Development Plan Amendment for such activity has been approved.

4.10 Conclusions and Recommendations

The Application proposes installation and operation of a WHP primarily to access the West Pool, but it will also enable production from the North Pool and the northernmost part of the South Pool. The WHP will consist of a CGS with topsides consisting of drilling facilities, wellheads and support services such as accommodations, utilities, a flare boom and a helideck. It will be tied back to the *SeaRose FPSO* to transport fluids for processing, storage and offloading. There will be no hydrocarbon storage on the WHP.

Taking into account the incremental recoverable oil from the currently producing pools, the Proponent indicates that 18.3 MMm^3 (115.1 MMbbls) can be produced from the WHP. Staff's estimate for the total oil recoverable from the WHP is 20.5 MMm^3 (128.7 MMbbls).

The depletion strategy proposed for the West Pool is secondary recovery by water flood. This is consistent with the strategy employed in the existing developments at the White Rose Field. The Application proposes drilling 13 producers and 13 water injectors from the WHP to deplete the remaining reserves in the West Pool. The WHP will also enable development of oil resources from the currently undeveloped North Pool and Blocks 2 and 5 of the South Pool, as well as infill drilling in the currently producing Terrace and Central Blocks of the South Pool.

Board staff's review of the Application, including the Proponent's seismic interpretations, production history, geological models and reservoir simulation models indicates that the proposed WREP is a reasonable and appropriate development strategy for the remaining oil resources in White Rose Field.

Using existing geological, reservoir engineering and production data, staff constructed geological and reservoir simulation models for the West and North pools and for Blocks 2 and 5 of the South Pool to provide independent estimates of STOOIP and reserves, and to confirm the estimates provided in the Application. While there are some discrepancies between the Proponent's and the Board staff's volumetric estimates due to slightly different interpretations and modelling procedures, overall, the methods used by the Proponent are considered appropriate and reasonable. Board staff notes significant upside potential in oil-in-place within the field.

Staff's review of the reservoir exploitation plan, production system, and facilities capabilities indicates that the capacity of the WHP is sufficient for the expected reserves to be produced, and the Proponent has addressed the relevant risks and issues from a resource management perspective.

The Proponent will be expected to provide updated comparisons of reservoir performance and reservoir simulation model predictions in the annual update to the Resource Management Plan for the West Pool and the North Pool. Staff also expects the Proponent to submit updated geological and reservoir simulation models for Blocks 2 and 5 when available.

The recoverable estimates presented in the Application are based on the assumption that the White Rose Asset produces out to the year 2030, which is five years beyond the original 20-year design life of the *SeaRose FPSO*. The Proponent indicates the end date of 2030 for estimating recoverable reserves is not a statement of intent to operate to a specific date beyond the current design life of the White Rose Asset original infrastructure. Further work will be required to assess the feasibility and impacts of extending the field life out to 2030 or beyond.

Resource Management staff also recommends that the West Pool pilot scheme (Decision 2010.01), consisting of the White Rose E-18 10 and E-18 11 wells, be considered to have ended, and that ongoing production and injection from these wells be allowed to continue as development wells in the West Pool. This recommendation is based on the assumption that the Proponent is moving toward timely execution of the commitments and exploitation scheme, as detailed in the Application. Therefore, the Board, in consultation with the Chief Conservation Officer, should evaluate whether the Proponent is meeting the commitments outlined in the Application at six-month intervals from the date of the Decision. If during such an evaluation the Board determines the commitments are not being met, production and injection from the E-18 10 and E-18 11 wells shall cease. Under these circumstances, no further production or injection from the West Pool would be permitted until a new DPA for such activity has been approved.

Should the Application not be approved, the pilot scheme will cease with no further production and injection from the E-18 10 and E-18 11 wells permitted until a new DPA for the West Pool is approved.

Staff concurs with the Application from a resource management perspective, and recommends approval subject to the following conditions:

> **Condition 1: That prior to drilling of any cuttings re-injection well, the Proponent must provide a report suitable to the Board describing the feasibility of injection, the impact on reservoir management and the impact on production accounting. The report must be submitted at least six months prior to ADW submission.**

Condition 2: That prior to initiating a gas flood or WAG scheme in the West Pool or any other pool to be developed from the WHP, the Proponent must provide simulation modelling or some other form of technical analysis which demonstrates that such a scheme will not be detrimental to oil recovery.

Condition 3: That the Proponent submit to the Board, within three years following initiation of production from the White Rose wellhead platform:

- **An updated evaluation of the White Rose Asset gas resources along with a description of activities to be undertaken to evaluate the resource; and**
- **A report on the advances and limitations of technologies such as compressed natural gas, floating liquefied natural gas, pipelines, associated onshore liquefied natural gas terminals and any other currently existing commercial offshore gas technologies and how these technologies relate to the gas resources of the White Rose Asset.**

Condition 4: That the Board, in consultation with the Chief Conservation Officer, will evaluate the commitments outlined in the Application at six-month intervals commencing from the date of the Decision. If during such evaluation the Board determines the commitments are not being met, production and injection from the E-18 10 and E-18 11 wells shall cease. In such circumstances, no further production or injection from the West Pool shall be permitted until a new Development Plan Amendment for such activity has been approved.

5.0 DECOMMISSIONING AND ABANDONMENT

The Proponent has provided little information on a decommissioning plan for both the wellhead platform and subsea infrastructure. The Application states that standard oilfield practices and current regulations will be followed when abandoning wells, decommissioning topsides, decommissioning and abandoning the CGS and removing all other equipment. The method of removing the CGS has yet to be determined. The Application states that all subsea equipment will be removed once safe.

This provides little explanation of the decommissioning strategy. A strategy should be developed to achieve maximum economic extension of the field life and to ensure key assets are not decommissioned prematurely to the detriment of production hubs and infrastructure. Some points highlighted in the UKCS Maximizing Recovery Review (Wood, 2014) suggest key areas for improvement from the industry as a whole to drive this area:

- Set up a forum to discuss decommissioning cost reduction by innovation in conjunction with the regulator and Operator.
- Industry should focus on technology for well abandonment and heavy lifts.
- Towards end of field life, a regulator should ensure proper steps and timelines are followed to avoid premature decommissioning of assets.
- Plan a "Late-Life Business Model", combining the skills of the Operator and decommissioning practitioner with a timely transition of the two.
- Ensure industry is being proactive to potentially change the decommissioning process.

From this, it is evident that further work is required by the Proponent to determine a plan for decommissioning. By thoroughly investigating and planning, it is possible for the Proponent to implement a decommissioning process that will lead to lower costs and/or extended field life.

It is recommended that the Proponent provide a Decommissioning Strategy that will greatly aid in maximizing the life of field and improving ultimate oil recovery.

References:

Wood, I., 2014. UKCS Maximizing Recovery Review: Final Report, United Kingdom Department of Energy and Climate Change: 68pp. Available from: http://www.woodreview.co.uk/.

6.0 THIRD PARTY ACCESS

Staff notes that at present there are no provisions in the Atlantic Accord Acts or regulations which address third party access to production and transportation facilities. Staff believes that access to these facilities may lead to development of hydrocarbon resources that could not support a dedicated facility.

It is in the public interest that where possible, access to existing production facilities by third parties be accommodated where excess processing, storage and transportation capacity exist. This will ensure that recovery of hydrocarbons is maximized.

Staff is not advocating that a Proponent pre-invest to accommodate third party production but it should be provided for where possible in the design of the facilities. Staff would expect the Proponent to consider all requests for use of spare capacity and to negotiate in good faith to reach an agreement. Where this is not possible and in the absence of regulations, staff believes that a mechanism should be established to ensure access to provide for the maximum recovery of oil and gas. In the event that a dispute between the Proponent and party requesting third party access should occur, the parties may apply to the Board for resolution.

It is a condition of approval that, provided excess processing, storage and/or transportation capacity exist, the Proponent must permit third party access to the offshore facilities on reasonable terms and conditions. **By commencing production, the Proponent shall be deemed to have agreed that in the event of a dispute, and an application to the Board, the Board may:**

- **Determine if third party access is to be provided for process, storage and transportation facilities;**
- **Specify the proportion of production to be taken by the Proponent; and**
- **Set fees for use of the facilities.**

7.0 DEVELOPMENT AND OPERATING COST DATA

7.1 Capital Cost Estimate

7.1.1 Development Drilling

The Proponent has estimated the development drilling capital costs to be $1.608 billion. This cost incorporates the drilling and completion of 38 development wells. Based on benchmarks available through current drilling activities in the Jeanne d'Arc Basin, Board staff feels that this cost is slightly underestimated.

7.1.2 WHP Construction

The capital cost for the WHP is estimated by the Proponent to be $2.35 billion. This estimate includes the topsides; CGS; construction of the dry dock; associated subsea equipment and tie-ins; transportation, installation and offshore hook up; existing infrastructure upgrades; and all associated engineering and project management.

7.2 Operating Cost Estimate

The addition of the WHP to the White Rose Field is expected to increase total field operating costs by approximately $20 million per year. As the primary function of the WHP is drilling, the majority of the operating costs are incorporated into the development drilling and completions capital costs.

8.0 SAFETY OF ACTIVITIES

Pursuant to the Atlantic Accord Acts, the Board must authorize all oil and gas activities in the Canada-Newfoundland and Labrador offshore area. Before issuing an authorization, the Board must consider the safety of the activity as a whole, as well as the safety of its component parts.

In the case of the White Rose Extension Project (WREP), the Proponent will be required to obtain authorizations for the pre-operation activities, commencing with tow-out, as well as for the operational phase.

In support of the various applications for authorization, the Proponent will need to demonstrate compliance with the provisions and conditions of the development plan amendment, the regulations, and the selected codes, standards and specifications. Before the C-NLOPB can issue any authorizations, the statutory requirements in the Accord Acts must be satisfied. The information that must accompany the application for authorization is specified in sections 6-9 of the *Newfoundland Offshore Drilling and Production Regulations*. This will include among other things a safety plan and contingency plan.

The Proponent is encouraged to contact the C-NLOPB at an early stage in their planning process to gain a full understanding of the application and approval process and as well to ensure that the expectations of the C-NLOPB will be met. In the case of well operations, additional approvals are required; approval to drill a well (ADW), approval to alter the condition of a well (ACW), well termination, and formation flow test program.

The Board has a safety assessment process to review applications for authorizations in a systematic and comprehensive manner. The objective of the assessment is to ensure that operators have considered all hazards of the activity and taken all the measures necessary to reduce the risks to a level that is as low as reasonably practicable (ALARP). The assessment considers the applicant’s commitments as to how they will ensure that the people, processes and equipment to be utilized are appropriate, meet the regulatory requirements and are in keeping with good industry practice.

Before the Board issues an authorization, a review is conducted of the supporting information submitted by the applicant against checklists based on the legislation, regulations and associated guidelines. The adequacy of the proposed safety management system is assessed. Pre-approval audits are undertaken that may include visits to installations, standby vessels and ancillary vessels. The applicant’s communications, logistical support and other land-based facilities may also be assessed.

Authorized activities are monitored for compliance with the applicable legislation and conditions attached to authorizations. In discharging its responsibilities, the C-NLOPB also monitors activities offshore through:

- Daily operating reports;
- Minutes of meetings of the joint occupational health and safety committee;
- Incident reports and investigating accidents and incidents; and
- Safety audits in the field and at applicant’s offices.

The C-NLOPB also advises applicants respecting the interpretation of regulations and monitors the work of Certifying Authorities (CA) to ensure that their certification activities conform to the scope of work approved by the Chief Safety Officer.

As the operator of the White Rose Field, the Proponent has submitted, on behalf of the interest holders, an application for a Development Plan Amendment seeking approval for the White Rose Extension Project (WREP). The activities associated with the WREP will be subject to the C-NLOPB’s assessment of safety processes.

The Proponent has submitted other development plan amendments for the White Rose Field exploitation program but these have all been associated with addition of further subsea assets to support the existing production facility. This WREP, however, proposes the design, construction, installation, operation and maintenance of a manned Wellhead Platform (WHP); this means the introduction of a significant new manned facility in the White Rose Field. However, it should be noted that the safety of activity which was considered in the original Development Plan staff analysis, is still germane to this amendment and has been considered in preparing this analysis.

8.1 Concept Overview

The WREP is focused on development of the West White Rose pool and has a base case development approach that will require 26 wells (13 oil producers and 13 water injectors). The current development approach in the White Rose Field is the use of subsea wells that are drilled by Mobile Offshore Drilling Units (MODUs) and are operated by a Floating Production Storage and Offloading (FPSO) facility, namely the *SeaRose FPSO*. The subsea well drilling programs in the Canada-Newfoundland and Labrador offshore area are challenging due to the harsh operating environment. This often results in significant non-productive drilling downtime. Also, the ability to conduct intervention activities to enhance oil recovery or address downhole technical issues, over the life of the well, is greatly reduced in comparison to conducting similar operations on platform based ``dry tree`` wells. Given the number of wells to be drilled and managed for the WREP, and given the challenges with conducting drilling and workover intervention operations for subsea wells, the Proponent has proposed to undertake the WREP using a Wellhead Platform (WHP) based development approach.

The main function of the WHP is as a drilling and well intervention platform for dry tree/wellhead operations; this is similar to Hibernia and Hebron. However, unlike Hibernia and Hebron, production will not occur on the WHP and no crude (unproduced or produced) will be stored on the WHP; reservoir fluids will be pumped to the *SeaRose FPSO* via subsea flowlines and will be processed through the *SeaRose FPSO* production train. Gas lift, gas flood and fuel gas will be supplied from the *SeaRose FPSO* gas compression/injection systems via a high pressure gas flowline. Water injection fluids will be supplied from the *SeaRose FPSO* via subsea flowlines and will be increased in pressure on the WHP through high pressure boost pumps prior to injection into the reservoir. There will be a test separator system on the WHP; however, following the testing process the oil, water and gas streams will be recombined and routed to the manifolds to be pumped to the *SeaRose FPSO* for production processing.

The WHP will act as a satellite facility in support of the *SeaRose FPSO* production operations. In this regard, the WHP Integrated Control and Safety System (ICSS) will be integrated with the *SeaRose FPSO* ICSS via microwave communication link. While primary control of the WHP systems will occur from the WHP, this integrated communication approach will allow the *SeaRose FPSO* to monitor the WHP manifolds, production trees, injection system and crude export system. It will also allow control of these systems from the *SeaRose FPSO* but only under restricted, controlled access. This “WHP-*SeaRose FPSO*” integrated control will not extend to the Drilling and Intervention systems on the WHP. The ICSS operator displays will follow the same graphics as the current *SeaRose FPSO* control systems to provide consistency of display between facilities.

8.2 Design

The Proponent has stated in the Application that the WHP is at the preliminary design stage. The Proponent has also indicated that the results of a number of activities such as model tests, studies and decisions on systems will be incorporated into the detailed design. The Proponent will be required to keep the C-NLOPB apprised of the design development, including the provision of key design philosophy documents, specifications and drawings. It is in this context that staff recommended that the following be a condition of the Board’s approval:

- **The Proponent submit to the Board a schedule of activities and decision points, including schedule of model tests, associated with the detailed design of the Wellhead Platform. The Proponent will submit selected test and study results to the Board as directed. The Board, in consultation with the Chief Safety Officer, will establish the date by which submissions must be made.**

The Atlantic Accord Acts requires that, before operations may be authorized, the installation shall have a Certificate of Fitness issued by a recognized Certifying Authority (CA). The *Newfoundland Offshore Certificate of Fitness Regulations* define the bodies which may act as a CA and require that a recognized CA undertake an independent examination of the design of facilities and survey the installation during construction and operation. The examination and survey by the CA shall consider if the facilities and installation are fit for purpose, comply with the regulations and can be operated without posing threat to people or the environment. The CA will verify the implementation of the quality assurance and quality control programs of the Proponent and its contractors.

The design review by the CA includes design premises, criteria and specifications, safety assessments, and the design of the installation as a whole. The CA's review is intended to ensure that the fundamental design principles and parameters, material characteristics, mathematical and physical models, major loads and load combinations are appropriate for the installation. A complete review of the detailed design is not normally conducted. However, selected documents are reviewed and independent calculations conducted to assess integrity of the installation. The methods used for the independent calculations may be different from those used by the designers and would be sufficient to ensure that the calculations used by the designers are appropriate. The Board staff will review the reports from the CA's design review, and meet regularly with the CA to discuss certification issues.

The CA will also review, approve and monitor the Proponent's maintenance and monitoring program. The CA will also conduct periodic surveys of the WHP to ensure compliance with the approved program, regulatory requirements and assess its fitness to operate safely without posing a threat to persons or the environment.

It should be noted that the Chief Safety Officer has to be satisfied with the level of review by the CA. This is determined through a review and approval of the Scope of Work, which is a requirement of the *Newfoundland Offshore Certificate of Fitness Regulations*, and through monitoring of the certification activities. Staff will monitor and audit the activities of the CA to ensure that it carries out its independent examination of the design of facilities and survey the installation during construction and operation in accordance with the approved Scope of Work.

It is identified in the Application that the proposed "life" for the WHP is beyond the current design life of the *SeaRose FPSO* yet this platform will support production by the *SeaRose FPSO*. This discrepancy in life of asset needs to be addressed well in advance of reaching the current design life of the *SeaRose FPSO*. The risk rests with the Proponent if at that time they are not able to demonstrate that the life of the *SeaRose FPSO* can be extended to align with the intended life and value of the WHP.

The North Sea Regulators are experiencing aging facilities and are studying the safe extension of facility life. The Board staff looks to the work of North Sea Regulators in the industry's development of best regulatory practice to extend the life of offshore facilities. To quote a HSE report on Aging Plants; "Ageing is not about how old the equipment is; it's about what you know about its condition, and how that's changing over time." Therefore the maintenance program will be a critical component of life expectancy of facilities. Staff recommends that the Board's approval include the following condition:

- **The Proponent submit to the Board its plans for reconciling the differences in design life for the Wellhead Platform, the *SeaRose FPSO* and the related subsea infrastructure. The Proponent must also include information, inclusive of a description of the related analysis and measures, that demonstrates to the satisfaction of the Chief Safety Officer, the rationale for any extension in the design life, including details of related verification activities by the Certifying Authority. The Board, in consultation with the Chief Safety Officer, will establish the date by which submissions must be made.**

8.2.1 Design Criteria

The WHP facility will have a design life of 25 years and will be designed to accommodate the production conditions throughout the life of the facility. The Proponent proposes to have common engineering and design practices across the White Rose Field and has committed to utilizing codes and standards that conform to those referenced in the regulations and associated guidelines. The Proponent has presented physical environmental criteria and geotechnical criteria for the WREP. The physical environmental criteria are based on historical data for the Grand Banks region and the geotechnical criteria are based on site specific geophysical and geotechnical data. The Application speaks to the current functional limitations of the *SeaRose FPSO*, as the production facility in the field. However, the Application does not provide a clear summary of the functional criteria for the various systems on the WHP. Therefore, staff recommends that the Board's approval include the following conditions:

- **The Proponent submit to the Board a summary of the Functional Design Criteria that will be the basis of the detailed engineering design work. The Board, in consultation with the Chief Safety Officer, will establish the date by which submissions must be made.**
- **Prior to the conclusion of detailed design, the Proponent submit a report, that is to the satisfaction of the Chief Safety Officer, which describes the scope, extent and outcome of environmental load model testing associated with the Wellhead Platform and also demonstrate that the outcome of this model testing has been appropriately dealt with in the structural design of the facility.**

8.2.2 CGS Design

As noted in the Application, the CGS will be a concrete structure with a central column (monoshaft) that will support the topsides approximately 32.5 meters above the low water mark and will have a cylindrical transition structure to mate the CGS with the topsides. The central column of the CGS will consist of a wet shaft, flooded to sea level and will not be accessible during normal operations. The central shaft will contain: well conductors, flexible risers, j-tubes, caissons and main mechanical outfitting steelwork.

The Proponent has chosen to use the ISO offshore structures standards for the design of the WHP structure. Specifically, *the ISO 19906: Petroleum and Natural Gas Industries – Arctic Offshore Structures, First Edition, 2010-12-15* pertains to the design, construction, transportation, installation and removal of offshore structures.

Design loads for the WHP include environmental, accidental and operational loads throughout the design service life. Loads associated with the construction, transportation, installation and removal are considered. Permanent and variable actions associated with environmental loads are also included (i.e. ice, seismic, oceanographic and meteorological). Limit states design methodology, equations, load and resistance factors are as specified in the ISO 19906 code as follows:

- Ultimate Limit States (ULS): resistance to extreme ice loads, Extreme Level Ice Event (ELIE);
- Abnormal (accidental) Limit States (ALS): accidental events and abnormal environmental events Abnormal Ice Level Event (ALIE);
- Serviceability Limit States (SLS): loads associated with normal functional use; and
- Fatigue Limit States (FLS): accumulated effect of repetitive actions.

In all aspects the WHP will be designed for an L1 exposure level, with the exception of the CGS shaft for iceberg impact which will be designed for an L2 exposure level iceberg impact event. The standard allows an Exposure Level L2 classification to be applied to manned-evacuated or unmanned platforms whose failure results in medium or low consequence for life, environment and asset. For greater clarity, the CGS shaft will be designed to withstand all other environmental loads based on an L1 exposure level; it is only the iceberg impact loading event that will be based on an L2 exposure level event.

To put this in context, an L1 event is the most severe loading level event defined by the standard and requires that each of the environmental design loads be based on the 10,000 year event. Hibernia and Hebron have been built to an L1 exposure level event in respect to all environmental loads for all aspects of each platform. An L2 exposure level event is based on the 1000 year event; in other words, there is a 10 times greater likelihood of being exposed to that loading event; albeit, it is a smaller load than the 10,000 year event. The larger the size of the iceberg being considered (i.e. the larger the iceberg impact load) the less likely it is that a facility will be exposed to an impact from that size iceberg because an iceberg of that size is less frequently seen on the Grand Banks. By choosing an L1 iceberg impact event as the design load, the Hibernia and Hebron facilities are able to withstand a higher level of iceberg impact loading than the WHP before progressive collapse is realized. In other words, the WHP has a 10 times greater likelihood, than the Hibernia or Hebron facilities, to be impacted by an iceberg that will impart a load that exceeds the design of the CGS to the extent that the CGS shaft may fail and result in the collapse of the facility.

The ISO standard allows for an L2 design approach if the following criteria are met:

- Ice management protocols allow sufficient time to shut-in wells and evacuate platform (i.e. the facility is unmanned at the time of the event – no persons at risk).
- All wells that can flow on their own in the event of platform failure should contain fully functional, subsurface safety valves that are manufactured and tested in accordance with applicable specifications.
- Oil storage is limited to process inventory and “surge” tanks for pipeline transfer.
- Pipelines have limited hydrocarbon release potential, due to low volume, low pressure or effective check valves or line block valves.

The first of these criteria is aimed at preservation of life and the latter three are aimed at minimizing the potential for a major hydrocarbon spill to the environment. The Proponent has indicated that it will take a conservative approach to ice monitoring and will ensure that all persons are removed in a planned and controlled manner prior to the WHP being exposed to an L2 iceberg impact event. All wells will be constructed with two downhole safety valves. As noted above, the WHP will not have any production or storage capabilities and the production flowlines to the *SeaRose FPSO* will be designed to have limited hydrocarbon release potential.

This proposed approach is a significant shift from the design philosophy for the Hibernia or Hebron facilities. Discussions have occurred with the Proponent on this proposed approach to better understand the commitments and mitigations on a number of matters and have resulted in enhancements to the proposed CGS design. One of these matters concerns the ability to eventually re-enter wells to allow proper abandonment of the wells after an event that has resulted in progressive collapse of the facility. This requires that a portion of the CGS immediately around the area where the well casing extends above the mudline must now remain intact and must not have shifted along the seafloor. The revised design will now safe guard at least 3 meters of the well casing string above the mudline even after an L1 level iceberg impact. Another matter concerns the availability of two intact well barrier envelopes after such an event. This has been accomplished by improving the well design to now include two downhole safety valves. As a result of this engagement by Board staff, the Proponent has also made a number of substantial enhancements from the original proposed design for the CGS. Overall, the current version of the CGS design is a much more robust structure.

There was also discussion regarding the proposed philosophies for completing full downstaffing of the facility, in a planned and controlled manner, well in advance of an L2 or greater iceberg impact event. Board staff stressed that the contingency plans around such an event are not to account for the use of life saving appliances (lifeboats and life rafts) as these are meant for emergency circumstances and not for planned movement of personnel from a facility. The Proponent has acknowledged this expectation and confirmed that plans will only account for the use of helicopters and personnel transfer to support vessels. It is also acknowledged that these plans must include sufficient time to address delays in downstaffing operations due to weather restrictions. Accurate forecasting, combined with historical data on frequency of consecutive days of interruption in moving personnel due to weather restrictions, must be used in a conservative manner to ensure that all personnel are able to be downstaffed in advance of an L2 or greater iceberg impact event.

Staff believe that a conservative approach to ice management should be maintained in respect of offshore operations and notes that for many years the preparation and submission of ice management plans have routinely been required of operators of drilling or production installations in areas prone to ice encroachment. Staff monitor operators' implementation of these plans on a continuous basis when ice is present, as part of its ongoing monitoring of offshore operations.

The Proponent states that it has a comprehensive ice management plan for existing White Rose Field operations. The current ice management philosophy for the *SeaRose FPSO*, as well as any mobile offshore drilling units which operate in the field, is based on the principle of iceberg avoidance. The current ice management plan provides ultimately for the orderly suspension of operations, and the flushing of production risers, prior to the *SeaRose FPSO* vessel moving off site. It is interesting to note that the Commissioner for the original White Rose development program recommended that the Board require that the Proponent's Ice Management Plan explicitly affirm the principle of avoidance of collisions with icebergs and establish prudent criteria for the mass of an approaching iceberg that would initiate disconnect procedures and an identified process to determine whether icebergs meet these criteria.

As highlighted by the commentary from the Commissioner for the original White Rose development, a related concern to successful advance downstaffing is the ability to detect and monitor, based on observable parameters, an L2 or greater iceberg. As discussed above, Ice Management has to take a conservative approach to T-Time calculation and to comprehensive ice monitoring to ensure that downstaffing is successfully completed well in advance of an L2 iceberg event even taking into account margins of error on timeframes for shutdown operations, iceberg drift and downstaffing operations. At this stage in the project, the Proponent would not have sufficient detailed design and operation information to allow for the completion of the associated Ice Management Plan. The Proponent has acknowledged that work is required to improve the existing Ice Management Plan for the White Rose Field so as to account for a fixed platform, to build in the appropriate level of conservatism in detecting and monitoring L2 or greater icebergs, based on observable parameters, and to have sufficient conservatism in downstaffing timeframes utilizing helicopter and personnel transfer methods of moving personnel off the facility in order to meet the L2 criteria of an unmanned facility at the time of an L2 event. Therefore, staff recommends that the following be a condition of the Board's approval:

- **At least six months prior to the issuance of any authorization related to the Wellhead Platform, the Proponent submit an Ice Management Plan that is to the satisfaction of the Chief Safety Officer and that defines observable criteria for categorizing if an approaching iceberg meets an L2 or greater classification upon which shutdown and downstaffing procedures will be implemented.**

8.2.3 Topsides Design

As noted in the Application, the main function of the WHP is to provide a platform for "dry tree" drilling, completions and interventions. Therefore, the topsides will consist of the following:

- drilling facilities
- intervention systems
- well bay and wellheads
- test separator
- manifolds for oil production, water injection, gas injection and gas lift
- high pressure water injection boost pumps
- fuel gas system
- utility systems
- safety systems
- integrated and satellite (FPSO remote) control systems
- telecommunications systems

- power generation
- living quarters for 144 POB

The Proponent states that the topsides facilities will have an operating weight of approximately 28,000 metric tonnes and will be designed for maximum isolation of hazardous/process equipment and well bay from the living quarters and helideck.

The drilling package will comprise a single derrick and associated drilling utilities. The drilling rig will be designed for year round operations and will allow for simultaneous drilling and intervention (wireline and coiled tubing) operations. The Proponent has indicated that the design of the drilling facilities will incorporate lessons learned from the design, construction and operation of White Rose, Terra Nova and Hibernia developments and other successful harsh environment projects around the world. The drilling package will include:

- Hoisting and Rotating Systems
- Tubular Handling System
- Drilling Hydraulic Power Unit
- High-Pressure Mud System
- Well Control System
- Drilling Control and Data Acquisition System
- Mud Bulks, Mixing, Solids Controls Systems
- Cementing Systems
- Rig Skidding System
- Cuttings Processing System
- Bulk Fluids Systems
- Well Completions System
- Well Intervention System

The Proponent outlined the basic design features for the drilling and completions programs for individual wells. These matters are subject to more detailed review as part of the Approval to Drill a Well (ADW) assessment process. At this stage there are two items of specific note. The first is the potential use of Electric Submersible Pumps (ESPs) as a form of artificial lift. This technology has not been used to date in the local offshore development projects but is widely used in the oil and gas industry for artificial lift. The management of safety around the potential use of ESPs will be reviewed during the authorization safety assessment and individual well ADW processes.

The second matter is the proposed use of hydraulic fracturing with multi-stage hydraulic fracturing equipment including the use of proppant. The term, hydraulic fracturing, covers a very broad scope of oil and gas drilling activities, from formation leak-off tests at the “bottom end of the scale”, to wellbore stimulation methods, to high water volume proppant infused formation fracturing to create and hold open permanent flow paths in the formation to aid in reservoir fluid movement for enhanced production. The Proponent does not provide sufficient information on the extent of hydraulic fracturing, or on the related systems, processes or training of persons to allow commentary on this matter other than note that the Application proposes some form of hydraulic fracturing. From a Safety of Activity perspective, any proposed systems, processes and training will be subject to review as part of the authorization safety assessment process.

The WHP will accommodate 20 well slots and the Proponent proposes to use conductor sharing wellhead technology in some or all of the well slots; therefore, allowing up to 40 wells to be drilled and operated from these 20 slots. The Proponent contends that this is proven technology with risks that are generally consistent with those of single slot systems. As this technology has not been used in this jurisdiction before, review was conducted of the experience and expectations in the North Sea regarding the use of such technology. The feedback from regulatory agencies in the North Sea was that this technology has only been used in very limited in-fill well circumstances and never as the intended base case design philosophy. Specific commentary on the use of such technology noted the need to consider: impact on risk due to wellhead proximity, impact on risk for collision avoidance in drilling the second of the paired wells, impact on limitations on size of intermediate and production casings and therefore on completion systems with the resultant limitations on intervention options. The Application does not contain sufficient detail or commitment regarding these matters to provide further commentary, other than to acknowledge a WHP design that will contain 20 drill slots. It is expected that more detailed information regarding these matters would be available from the FEED stage as input to the Detailed Design stage and that this would be inclusive of a comparative analysis of impact on risk in respect to mono conductor versus dual conductor arrangements. It is also expected that the Proponent better demonstrate the application of good industry practice from the North Sea, of the use of such technology, and account for this in the design of the CGS and in the plans for “slot management” throughout the life of the WHP. Therefore, staff recommends that the following be a condition of the Board’s approval:

- **The Proponent submit information, that is to the satisfaction of the Chief Safety Officer, that provides a more comprehensive understanding of the wellhead arrangements and layouts being proposed, a quantitative comparison of risk between the proposed wellhead layout for dual conductor arrangement versus mono conductor arrangement, clarity of the enhancements in protocols for managing wellbore collision avoidance and detail on design and slot management considerations resulting from a review of good industry practice of using such technology in the North Sea. The Board, in consultation with the Chief Safety Officer, will establish the date by which submissions must be made.**

Utilities Systems will consist of: Seawater Lift System, Potable and Fresh Water System, Compressed Air System, Nitrogen Generation and Distribution System, Heating, Ventilation and Air Conditioning Systems, Sewage Treatment System, Closed Drains System, Open Drains System, Diesel Fuel System, Aviation Fuel. It is noted that the application does not provide any commentary of Lifting Systems that will be incorporated into the facility such as Pedestal Cranes, BOP Handling Cranes, Gantry Cranes, potential Drill Floor Manriding Boom Cranes, Manriding Tuggers or Work Tuggers.

There are five key Safety Systems identified for the WHP:

1. Alarm and Shutdown Systems – this will include: Emergency Shutdown System, Process Control System, Drilling Monitoring System, Fire and Gas System and Information Management System. The WHP ESD system will be interfaced with the *SeaRose FPSO* ESD system and will be based on API 14 C and any other requirements of the regulations.
2. Fire and Gas Detection System – this will be an integrated part of the WHP ICSS and will be interfaced to the Fire and Gas System to execute facilities shutdown levels, process isolations and electrical isolations.
3. Fire Suppression Systems – the Proponent has indicated that the active fire protection systems will meet the requirements of the Newfoundland Offshore Petroleum Installation Regulations and referenced standards and that the specific types of systems will be decided based on the results of the fire and explosion risk analysis.
4. Safety Stations – there will be two muster points, one in the temporary safe refuge (TSR) near the primary lifeboat station and one near northeast corner of the WHP near the secondary lifeboat station. The TSR will also have an emergency command centre.
5. Escape and Evacuation – the Proponent commits to having 200% lifeboats and 100% life rafts and will evaluate and incorporate the necessary technology to launch the lifeboats and life rafts.

It is noted in the Application that production systems will be designed for sour service and that the fire and gas detection system will provide early detection of elevated levels of toxic gases. Current production operations in the Canada-Newfoundland and Labrador offshore area have all encountered significant levels of Hydrogen Sulfide (H_2S) both from reservoir souring and from onboard sources such as slops tanks and oily water handling systems. Hydrogen sulfide has also been encountered during well intervention operations. The *Newfoundland Offshore Petroleum Installations Regulations* require the installation to be equipped with a gas detection system in every part of the installation in which hydrogen sulphide gas or any type of hydrocarbon gas may accumulate. The Proponent is required to provide a robust gas detection system and further clarity of its plans for gas detection, and particularly for H_2S gas detection, should be provided. Therefore, staff recommends that the following be a condition of the Board's approval:

- **Prior to completion of detailed design of the Wellhead Platform gas detection system, the Proponent submit information, that is to the satisfaction of the Chief Safety Officer, that provides a more comprehensive understanding of the approach to H_2S gas detection for the Wellhead Platform and that demonstrates compliance with the *Newfoundland Offshore Petroleum Installations Regulations*.**

It is noted that the Application does not speak to the minimum design criteria or timeframe that the TSR must provide a safe haven. Experience has demonstrated the threat posed by smoke entering the TSR and associated evacuation systems, including both lifeboats and the helicopter deck. A similar threat is posed by gas ingress either into the TSR or around lifeboat stations and/or the helicopter deck. Also, the Proponent has not identified in detail the specific evacuation systems for its facilities nor does the Proponent commit to using the best practicable evacuation technology. The Proponent will be required to demonstrate to the satisfaction of the Chief Safety Officer that the best practicable evacuation technology available will be utilized on the WHP. This is consistent with the requirements of Condition 32 of the original White Rose development plan decision report which stated:

"The Proponent demonstrate, to the satisfaction of the Board, that the best practicable evacuation technology is being used on the production and drilling installations prior to beginning operations in the field."

In consideration of the above, staff recommend that the following be conditions of the Board's approval:

- **Prior to completion of the Accommodations Module detailed design, the Proponent submit, to the satisfaction of the Chief Safety Officer, its criteria and rationale for the minimum timeframe that the temporary safe refuge (TSR) must continue to function as a safe haven and remain unimpaired as a result of any of the credible design events.**
- **Prior to completion of the Evacuation System detailed design, the Proponent submit a report that is to the satisfaction of the Chief Safety Officer which demonstrates that the best practicable evacuation technology is being employed on the Wellhead Platform.**

The living quarters will be protected from hazardous areas by incorporating fire resistant and blast rated external walls, roofs and undersides. The helideck will be located on the southwest corner of the living quarters and will be in keeping with the requirements of CAP 437. The Proponent indicates that all cabins will be designed for two persons who will work on alternating shifts. However, the Application provides very little additional commentary on features of the accommodations that will facilitate the physical, mental and emotional well being of the personnel who will work on the facility.

The operator has not provided the required schematics of the topsides facilities, as required by Section 3.9.2 of the Development Plan Guidelines and therefore has not provided sufficient information to provide clear understanding of the planned facility layout to demonstrate that safety of personnel and facility has been optimized. Therefore, staff recommends that the following be condition of the Board's approval:

- **The Proponent submit information, that is to the satisfaction of the Chief Safety Officer, which provides a more comprehensive understanding of the layout of the facility including the layout and features of the accommodations and the lifting systems that will be employed on the facility. The Board, in consultation with the Chief Safety Officer, will establish the date by which submissions must be made.**

The Proponent highlights the importance of facility layout to provide maximum separation between the well bay and the living quarters and helideck. The Application acknowledges the importance of hazardous area classification to control potential ignition sources by selection of proper rated electrical equipment and in properly locating ventilation inlets and outlets and combustion engine air inlets and exhaust outlets. Hazardous areas will be analyzed to assure adequate ventilation or provision of ventilation to prevent accumulation of flammable gases or vapours and to reduce the likelihood of ignition. Non-hazardous “safe” areas will include pressurization systems to prevent the migration of fumes or vapours from hazardous areas.

The Application indicates plans for a multi-tier Emergency Shutdown System (ESD); ESD 1 being the highest Abandon Platform level down to ESD 5 being individual package shutdown. It also acknowledges a Drilling Shutdown level in the ESD hierarchy. The Proponent highlights that the ESD system will comply with all relevant statutory requirements, codes and standards and will remain operational in an emergency. The WHP ESD system will be interfaced with the *SeaRose FPSO* ESD System to shutdown the import and export of hydrocarbons to either facility during emergency situations. There is no commentary, however, to indicate executive and/or emergency actions that would occur if communications are lost between the WHP ICSS and the *SeaRose FPSO* ICSS. It is expected that this matter will be addressed as part of the contingency planning associated with WHP operations and the design of the integrated ESD system. The Proponent is required to address this matter in the Safety Plan for the WHP and in the updates to the Safety Plan for the *SeaRose FPSO*. Assessment of the Safety Plan for this project will occur prior to the issuance of an authorization.

Emergency power generation capabilities will be available on the WHP to ensure the availability and operability of the required systems during emergency events and in the event of loss of main power generation. The Proponent is reminded that equipment that is required to “stay live” during an emergency event must be appropriately rated for credible gas events regardless of the hazardous area rating for the area in which the equipment is located.

The Application indicates that passive fire and blast protection will be utilized on topsides primary structures and on hydrocarbon vessels that contain significant quantities of hydrocarbons. The Concept Safety Analysis acknowledges that production and gas injection production trees will be provided with insulating fire blankets. It also acknowledges that the temporary safe refuge external walls will be fire and blast rated as well as the walls running north to south on the Cellar Deck and the Middle deck to segregate hazardous areas.

Throughout the Application, there are references to the use of various industry codes and standards, as well as commitments to meeting the statutory requirements. The Proponent is reminded that the regulations reference the use of specific codes and standards and for those specific cases, any proposals for the use of alternate codes or standards may only occur if there is an approved Regulatory Query where the Proponent has demonstrated to the satisfaction of the Chief Safety Officer that the alternate code or standard provides an equivalent or better level of safety than the one referenced by the regulations.

The Application indicates that there are no anticipated modifications required to the *SeaRose FPSO* production systems and that the modifications that are anticipated are related to the integration of control systems and telecommunications between the WHP and the *SeaRose FPSO*. These modifications will be managed through the existing Management of Change processes and will include any new training for *SeaRose FPSO* personnel and updating of *SeaRose FPSO* documentation including the Safety Plan and Emergency Response Plans. The Proponent is also reminded that such changes impact the consideration of safety of activities associated with the authorization under which the *SeaRose FPSO* operates. As such, these matters will be addressed during the staff’s review of the updated authorization.

Therefore, it is a condition of the Board’s approval that:

- **Prior to bringing live the modified systems on the *SeaRose FPSO*, the Proponent submit updated information on people, processes and equipment, that is to the satisfaction of the Chief Safety Officer, in respect to the associated *SeaRose FPSO* Operations Authorization.**

Furthermore, the Application notes that the WHP design will include provision for future tie-back of one subsea drill centre for oil development in the near field. The WHP will also include provisional space for a modular well clean-up package. Any such addition to equipment is to be addressed through amendment to the authorization.

8.3 Authorization of Construction and Installation Activities

The Proponent proposes to tow the CGS to the offshore site and then conduct topsides mating and integration in the White Rose Field. All prior development projects in the Canada-Newfoundland and Labrador offshore area, both gravity based and floating facilities, have seen this mating and integration work being completed in sheltered waters, thus minimizing the extent of integration and commissioning being conducted in the offshore area. The approach proposed has a number of areas of concern. In general, there is a lack of detail around the scope of activities, size of workforce required and timing of activities. As well, in order to undertake this approach, the Proponent is planning to use a new vessel that will be the world's largest ship of its kind but is still being built; therefore there will be limited operational history or experience with this vessel. The Proponent does not provide sufficient commentary on how this risk will be managed.

This approach will mean significant POB working in the offshore area undertaking the mating, integration and commissioning activities offshore. This will mean a significant increase in POB movement to and from the offshore area compared to any other project to date. The Concept Safety Analysis notes that helicopter transportation is the single biggest contributor to risk in terms of Potential Loss of Life (PLL) and is one of two factors that contribute to the "frequency of hazards resulting in 3 or 4 fatalities approach the intolerable threshold". The CSA does not account for this increased POB movement resulting from moving the mating and integration work from a near shore deepwater sheltered location to the site in the offshore field.

This approach will require POB accommodations capacity offshore that has not been required on any other project to date and the Application has not provided any meaningful information on how this POB capacity requirement will be handled or the implications on managing risk. The Application mentions several possible options for trying to accommodate the extra POB. One is the use of an accommodation module. The other involves utilizing POB space from the *SeaRose FPSO*, yet there is no commentary on the implications on *SeaRose FPSO* operations even though the *SeaRose FPSO* traditionally has utilized its full POB capacity for its own operations and will require use of its own POB capacity to support the necessary modifications to be able to act as a remote operation centre. However, these options are only mentioned in passing and the application does not provide any clear plan on how the POB capacity requirements will be managed.

The lack of commentary and analysis of these matters have a significant impact on the level of understanding of the proposed approach for executing this aspect of the development project and also have significant impact on the risk profile for this project. The operator has not presented an appropriate comparative consideration of other options, such as undertaking this mating and integration activity at a deepwater site in sheltered waters as has been done with all other projects. The operator has not demonstrated that they have considered the full scope of options for undertaking mating and integration and have not demonstrated that the proposed approach is the lowest risk option in respect to safety of activity. Therefore, staff recommends that the following be a condition of the Board's approval:

- **Prior to tow out of the Concrete Gravity Structure (CGS) from the dry dock, the Proponent submit a report, that is to the satisfaction of the Chief Safety Officer, which demonstrates that the proposed approach to Topsides-CGS mating and integration activities is the lowest risk option in respect to safety of activity.**

8.4 Operations and Maintenance

The safe operation of a complex facility such as the WHP and its concurrent satellite support to the *SeaRose FPSO* depends on it being operated and maintained under a robust management system that has a focus on people, processes and equipment. In this regard, the Proponent will be operating and maintaining the WHP in accordance with the Husky Operational Integrity Management System (HOIMS).

The people component of the management system must address, with great clarity, the organizational structure, the roles and responsibilities for the various positions in the organizational structure and a comprehensive program for ensuring there is a trained and competent workforce both onshore and offshore. The Application provides a high level summary of the reporting relationships between the onshore and offshore and between the WHP and the *SeaRose FPSO*. The Application notes that training and competency will be managed under the same model and processes as is currently utilized for the *SeaRose FPSO*. In general, these are matters that are assessed as part of the review for issuance of an authorization and will need to be addressed by the Proponent at that time.

Section 72 of the *Newfoundland Offshore Area Petroleum Drilling and Production Regulations* requires that: "all personnel have, before assuming their duties, the necessary experience, training and qualifications and are able to conduct their duties safely, competently and in compliance with the Regulations".

Further, the *Canada – Newfoundland and Labrador Offshore Marine Installations and Structures Occupational Health and Safety Transitional Regulations* require all offshore personnel to be instructed and trained in the procedures to be followed by each employee in the event of an emergency; and to be informed of the location, use and operation of emergency and fire protection equipment. A particular challenge is how personnel can gain competency for systems and processes on a facility that is still being built. The Proponent will be expected to deal with such matters in its application for an authorization. However, staff recommends that the following be a condition of the Board's approval:

- **At least one year prior to the Wellhead Platform operating under an authorization from the Board, the Proponent submit a Training and Competency Plan associated with operation and maintenance of the Wellhead Platform that is to the satisfaction of the Chief Safety Officer.**

The Application also indicates that asset integrity will take a life of field approach that is consistent with the existing asset integrity system being utilized for the *SeaRose FPSO*. This system is very consistent with the regulatory expectations of focusing on Safety Critical Equipment (SCE) and having related Performance Standards to ensure that the SCE functions as an effective barrier against incidents and to ensure that the equipment operates within an acceptable range. The Application also notes that the approach to operating and maintenance procedures and to maintenance strategies will also be consistent with the approach being used for the *SeaRose FPSO*.

The development and rollout of appropriate and accurate procedures has traditionally presented a challenge to operators for new installations. The Proponent will be required to provide the C-NLOPB with an acceptable strategy for the development, rollout and tracking of operating and maintenance procedures and other required documentation inclusive of contingency plans. This strategy should be developed early in the design phase such that it can be effectively implemented without the necessity of extensively reworking or having to develop procedures ad hoc after operations have commenced. It is noted that as part of the original White Rose Development review, the Commissioner recommended that the Board require that the Proponent's operational safety planning, including its evacuation plans, consider the simultaneous occurrence of two or more extreme events, involving accidental events in combination with wind, sea and ice. It is an interesting note that the ability to safely launch and operate lifeboats in sea ice is a current topic of discussion with offshore operators. It is apparent that contingency plans, including emergency evacuation plans, will need to be robust enough to address the possible simultaneous occurrence of accidental events in combination with heavy seas and ice/iceberg encroachment or other extreme events. The Proponent will be expected to deal with these matters in its application for an authorization; however, staff recommends that the following be a condition of the Board's approval:

- **At least one year prior to the Wellhead Platform operating under an authorization from the Board, the Proponent submit to the Board its strategy for the development and documentation of the detailed operations and maintenance procedures and contingency plans necessary for the safe operation of the installation. The Proponent must also ensure that its contingency plans address, to the satisfaction of the Chief Safety Officer, the possibility of simultaneous occurrence of an accidental event on the**

Wellhead Platform in combination with adverse environmental conditions and that these contingency plans provide clear detail of the risk reduction measures that will be undertaken when such adverse environmental conditions are forecast and/or realized.

The Proponent notes that it has well established infrastructure and service arrangements to support White Rose Field operations and that this will also be used to support the WHP operations. The Proponent also notes that the WHP operations will have the same suite of communications capabilities as their other White Rose Field operations, inclusive of redundancy and backup on these systems to provide the maximum continuous uninterruptible communications capability available for the anticipated environmental conditions. These are all matters that are assessed as part of the review for issuance of an authorization.

The Proponent notes that they have an existing fleet of support vessels servicing existing operations in the White Rose Field. The fleet is increased or decreased in size depending on demands and requirements. This same approach will be used to ensure the size of the support fleet is appropriate to include servicing of the WHP. The specifications, inclusive of emergency response capabilities, for the existing support vessels are currently in place. It is understood that these specifications will be utilized for the WHP support vessels. These are all matters that are assessed as part of the review for issuance of an authorization.

The Proponent notes that they have existing Incident Coordination Plans, an Onshore Emergency Response Organization and onshore facilities to support management of emergency events that may occur in the White Rose Field. These same onshore capabilities will be employed to support the WHP operations. The WHP will have its own installation specific emergency response plans. The WHP will have the necessary designated offshore emergency response teams and response facilities to deal with the various defined credible emergency scenarios. These are all matters that are assessed as part of the review for issuance of an authorization.

8.5 Safety Analysis and Commitment

Section 43 of the *Newfoundland Offshore Petroleum Installations Regulations* requires the Proponent, at the time of submission of its Development Plan, to provide to the Board its definition of target levels of safety concerning its installation, and a Concept Safety Analysis (CSA) respecting the installation. The CSA that was submitted describes the:

- safety design features and safety systems proposed for the prevention, detection and control of potential Major Hazards, as well as the mitigations of associated risks;
- target Levels of Safety; and
- identified Major Hazards and the associated assessment of risk.

Staff note that the Proponent contends that a project Quantitative Risk Analysis (QRA) will replace the CSA. In reality, the CSA will become embedded within the much more extensive QRA. However, the CSA must be maintained as required by Section 43 of the *Newfoundland Offshore Petroleum Installations Regulations*. Therefore the elements and details of the CSA must be clearly distinguishable within the QRA or must be maintained as a standard alone document.

Staff note that the CSA concludes that risks are within the ALARP region but it does highlight that the "frequencies of hazards resulting in 3 or 4 fatalities approach the intolerable threshold". It is understood that this information will be refined as detailed design progresses and the CSA highlights the need to review the adequacy of potential risk reduction measures to prevent, mitigate and safeguard against the major risk contributors. The Proponent will have to be able to demonstrate that all reasonable efforts have been made to mitigate these risk to as low as reasonably possible. It is also noted that the CSA does not explicitly quantify risk due to dropped objects even though dropped objects is a major risk trend in the offshore and has significant consequences if not properly mitigated. The CSA proposes a number of recommendations to ensure that the assumptions made at this pre-detailed design stage are "reviewed and revised at detailed design stage, when more detailed information is available, to facilitate a more robust and representative assessment". The CSA provides a list of recommended safety studies. The Proponent notes that additional safety studies will be required during detailed design but does not provide definite commitments in this regard. The Application fails to provide either sufficient commitment to, or a strategy for, completing a detailed suite of safety studies required to support the design and provide the basis for the Safety Plan. Staff notes that other projects derived significant benefit from the development of a Safety Assessment Plan to plan, track and manage safety studies during the design of the facilities. The C-NLOPB will require that the Chief Safety Officer be informed of the actions which the Proponent proposes to take to satisfy recommendations of the safety studies, and that the Certifying Authority ensure that the recommendations have been properly satisfied.

The Proponent is expected to develop, at an early stage, a plan to document and track the suite of safety studies required for detailed design and staff believes that the plan should include the Proponent's schedule for satisfying the recommendations presented in its CSA. Further to this, staff expects that the Certifying Authority review this plan, and the studies under it, to ensure appropriate safety assessment is undertaken and implemented in the design, construction, installation and operations phases of the WREP. Staff believes that a systematic and continuous approach to the elimination or reduction of risks to people, the environment, assets and operations is required. The Proponent will be expected to keep the C-NLOPB apprised of the design development, including the provision of key design philosophy documents, specifications and drawings. Therefore, staff recommends that the following be conditions of the Board's approval:

- **The Proponent submit a plan, that is to the satisfaction of the Chief Safety Officer, to document and track the suite of safety studies required for detailed design. The plan is to include a schedule for satisfying the recommendations provided in the Proponent's Concept Safety Analysis. The Board, in consultation with the Chief Safety Officer, will establish the date by which submission must be made.**
- **Prior to submission of any application for conducting activities under an authorization from the Board, the Proponent demonstrate, to the satisfaction of the Chief Safety Officer, that the recommendations from the Concept Safety Analysis have been addressed in a manner that brings risk to as low as reasonably practicable (ALARP).**

The Proponent states in its Application that the approach to quality management for the operation of the facility will be consistent with the requirements of the C-NLOPB *Drilling and Production Guidelines*. It further notes that monitoring the effectiveness of the management system and the facility safety plan are key aspects of HOIMS. The Application does not provide adequate commentary on the Quality Assurance program and Quality Control program that will be applied throughout the design, construction, integration and commissioning phases of the project. The *Newfoundland Offshore Petroleum Installations Regulations* require an installation to be designed, constructed, installed and commissioned in accordance with standards respecting quality assurance published by the Canadian Standards Association. The *Newfoundland Offshore Certificate of Fitness Regulations* require the CA to determine whether the design, construction and installation are in accordance with the regulatory requirements.

The CA reviews the design and surveys the installation during all phases of its development to determine among other regulatory requirements compliance with the quality standards. Pursuant to these regulations, the Board's Chief Safety Officer has to be accepting of, and approve, the Scope of Work for the CA where the Chief Safety officer is satisfied that such scope will provide the means for determining, among other things, that the installation has been constructed in accordance with an acceptable quality assurance program.

Staff recommends that the following be conditions of the Board's approval:

- **The Proponent submit information to the Board that details the Quality Assurance Program and Quality Control Program that will be applied throughout all pre-operation phases of the project. The Board, in consultation with the Chief Safety Officer, will establish the date by which submissions must be made.**

- **The Proponent submit, to the satisfaction of the Chief Safety Officer, the Scope of Work for the Certifying Authority. The Board, in consultation with the Chief Safety Officer, will establish the date by which submission must be made.**

The Application acknowledges the requirement to put in place a Safety Plan for the WHP that will be in keeping with the *Newfoundland Offshore Petroleum Drilling and Production Regulations*. The Proponent acknowledges that the Safety Plan will provide a comprehensive summary of the components of the management system that will apply to the WHP operations and will outline the measures implemented for the safety and well-being of personnel, preservation of the environment and protection of the installation. The Application also acknowledges the requirement to put in place a Security Plan as part of the overall WHP contingency plans. These are all matters that are assessed as part of the review for issuance of an authorization.

8.6 Decommissioning

The Proponent commits to the eventual decommissioning and abandonment of the WHP at the end of the life of the project. This will consist of the proper plugging and abandonment of all wells in accordance with regulatory requirements and good oilfield practice. The topsides and CGS will then be decommissioned. The Proponent has committed that the WHP will not be disposed of offshore, nor converted to another use on site. All decommissioning activities will be assessed as part of the review for issuance of related authorizations.

8.7 Recommendation

Staff recommends from a safety perspective that the Application be approved subject to the following conditions:

1. **The Proponent submit to the Board a schedule of activities and decision points, including schedule of model tests, associated with the detailed design of the Wellhead Platform. The Proponent will submit selected test and study results to the Board as directed. The Board, in consultation with the Chief Safety Officer, will establish the date by which submissions must be made.**

2. **The Proponent submit to the Board its plans for reconciling the differences in design life for the Wellhead Platform, the *SeaRose FPSO* and the related subsea infrastructure. The Proponent must also include information, inclusive of a description of the related analysis and measures, that demonstrates to the satisfaction of the Chief Safety Officer, the rationale for any extension in the design life, including details of related verification activities by the Certifying Authority. The Board, in consultation with the Chief Safety Officer, will establish the date by which submissions must be made.**

3. **The Proponent submit to the Board a summary of the Functional Design Criteria that will be the basis of the detailed engineering design work. The Board, in consultation with the Chief Safety Officer, will establish the date by which submissions must be made.**

4. **Prior to the conclusion of detailed design, the Proponent submit a report, that is to the satisfaction of the Chief Safety Officer, which describes the scope, extent and outcome of environmental load model testing associated with the Wellhead Platform and also demonstrate that the outcome of this model testing has been appropriately dealt with in the structural design of the facility.**

5. **At least six months prior to the issuance of any authorization related to the Wellhead Platform, the Proponent submit an Ice Management Plan that is to the satisfaction of the Chief Safety Officer and that defines observable criteria for categorizing if an approaching iceberg meets an L2 or greater classification upon which shutdown and downstaffing procedures will be implemented.**

6. **The Proponent submit information, that is to the satisfaction of the Chief Safety Officer, that provides a more comprehensive understanding of the wellhead arrangements and layouts being proposed, a**

quantitative comparison of risk between the proposed wellhead layout for dual conductor arrangement versus mono conductor arrangement, clarity of the enhancements in protocols for managing wellbore collision avoidance and detail on design and slot management considerations resulting from a review of good industry practice of using such technology in the North Sea. The Board, in consultation with the Chief Safety Officer, will establish the date by which submissions must be made.

7. **Prior to completion of detailed design of the Wellhead Platform gas detection system, the Proponent submit information, that is to the satisfaction of the Chief Safety Officer, that provides a more comprehensive understanding of the approach to H_2S gas detection for the Wellhead Platform and that demonstrates compliance with the *Newfoundland Offshore Petroleum Installations Regulations*.**

8. **Prior to completion of the Accommodations Module detailed design, the Proponent submit, to the satisfaction of the Chief Safety Officer, its criteria and rationale for the minimum timeframe that the temporary safe refuge (TSR) must continue to function as a safe haven and remain unimpaired as a result of any of the credible design events.**

9. **Prior to completion of the Evacuation System detailed design, the Proponent submit a report that is to the satisfaction of the Chief Safety Officer which demonstrates that the best practicable evacuation technology is being employed on the Wellhead Platform.**

10. **The Proponent submit information, that is to the satisfaction of the Chief Safety Officer, which provides a more comprehensive understanding of the layout of the facility including the layout and features of the accommodations and the lifting systems that will be employed on the facility. The Board, in consultation with the Chief Safety Officer, will establish the date by which submissions must be made.**

11. **Prior to bringing live the modified systems on the *SeaRose FPSO*, the Proponent submit updated information on people, processes and equipment, that is to the satisfaction of the Chief Safety Officer, in respect to the associated *SeaRose FPSO* Operations Authorization.**

12. **Prior to tow out of the Concrete Gravity Structure (CGS) from the dry dock, the Proponent submit a report, that is to the satisfaction of the Chief Safety Officer, which demonstrates that the proposed approach to Topsides-CGS mating and integration activities is the lowest risk option in respect to safety of activity.**

13. **At least one year prior to the Wellhead Platform operating under an authorization from the Board, the Proponent submit a Training and Competency Plan associated with operation and maintenance of the Wellhead Platform that is to the satisfaction of the Chief Safety Officer.**

14. **At least one year prior to the Wellhead Platform operating under an authorization from the Board, the Proponent submit to the Board its strategy for the development and documentation of the detailed operations and maintenance procedures and contingency plans necessary for the safe operation of the installation. The Proponent must also ensure that its contingency plans address, to the satisfaction of the Chief Safety Officer, the possibility of simultaneous occurrence of an accidental event on the Wellhead Platform in combination with adverse environmental conditions and that these contingency plans provide clear detail of the risk reduction measures that will be undertaken when such adverse environmental conditions are forecast and/or realized.**

15. **The Proponent submit a plan, that is to the satisfaction of the Chief Safety Officer, to document and track the suite of safety studies required for detailed design. The plan is to include a schedule for satisfying the recommendations provided in the Proponent's Concept Safety Analysis. The Board, in consultation with the Chief Safety Officer, will establish the date by which submission must be made.**

16. **Prior to submission of any application for conducting activities under an authorization from the Board, the Proponent demonstrate, to the satisfaction of the Chief Safety Officer, that the recommendations from the Concept Safety Analysis have been addressed in a manner that brings risk to as low as reasonably practicable (ALARP).**

17. **The Proponent submit information to the Board that details the Quality Assurance Program and Quality Control Program that will be applied throughout all pre-operation phases of the project. The Board, in consultation with the Chief Safety Officer, will establish the date by which submissions must be made.**

18. **The Proponent submit, to the satisfaction of the Chief Safety Officer, the Scope of Work for the Certifying Authority. The Board, in consultation with the Chief Safety Officer, will establish the date by which submission must be made.**

9.0 OPERATIONS

The following is an analysis of the Application in relation to well operations as well as the certification of the proposed installation and facilities.

9.1 Well Operations

Platform wells will be extended reach wells with three-dimensional trajectories and horizontal or near-horizontal sections. The planned completions will be open-hole and perforated designs, similar to what is currently being used on the subsea wells in the White Rose Field. The Proponent has confirmed that the design of the wellheads and the platform trees will meet all applicable regulations, codes and standards.

The Proponent also affirmed the drilling, completion and well intervention activities will be executed in accordance with established practices, policies and procedures, updated as necessary in relation to any changes to regulatory requirements. Staff will verify this in due course when assessing any application for Operations Authorizations for these activities.

Given that the wellhead platform is a new concept for the Canada-Newfoundland and Labrador offshore area, staff identified the need for the Proponent to ensure that its application for Operations Authorization addresses the following unique aspects, in addition to all other regulatory requirements pertaining to the authorization process:

- The use of dual conductor technology where two wells can be co-located in the same conductor slot will require the Proponent to develop appropriate well-bore collision avoidance policies and procedures. Additional training of personnel in relation to this technology will also need to be described in the application for authorization.
- Well slot allocation will need to be assessed in the context of the need to dedicate certain well slots for extended reach drilling opportunities within the White Rose Field. Such wells are likely to require different casing architecture in terms of larger diameter conductor and surface casing in order to reach extended targets.
- A detailed description of the policies, procedures and equipment in relation to electrical submersible pumps will need to be provided if this technology is used.
- Well barrier analysis will need to be undertaken for each critical phase of the well construction process to verify compliance with the dual well barrier requirement. This is particularly important in relation to the fact that the governing design code specifies the need for two fail safe close down-hole safety valves to preserve the dual well barrier requirement in the event that the platform is exposed to an abnormal level ice load.
- Given that certain contractors engaged to provide drilling and other well services may be “new” to the Canada-Newfoundland and Labrador offshore area, the Proponent will need to ensure that an analysis of contractors’ policies and procedures is conducted for conformity to regulatory requirements and the Proponent’s management system documentation. Any gaps will have to be addressed in the form of a “bridging” document. This is typical of good oilfield practice and is particularly important in relation to well operations, well barriers and well control.

9.2 Certification

The wellhead platform meets the definition of “drilling installation” in the *Newfoundland Offshore Certificate of Fitness Regulations*. As a result, a certificate of fitness must be issued by a recognized certifying authority. The Proponent engaged the services of a certifying authority during the front-end engineering design. This early engagement enables feedback in relation to conformance of the design with the codes, standards, and other requirements prescribed in the regulations.

Although the same certifying authority has been selected for the wellhead platform as was used for the *SeaRose FPSO*, it will be necessary to submit a specific scope of work to the Board's Chief Safety Officer for approval. Pending approval of the Application, the certifying authority will be advised to proceed with the submission of the scope of work. Staff will assess the work scope for conformity with regulatory requirements.

Any proposed use of an "accommodations installation" in the offshore area will also require a certificate of fitness by a recognized certifying authority.

The process for issuing certificates of fitness are well established and the Proponent will be expected to fully adhere to these requirements.

9.3 Recommendation

From an operations perspective, staff recommends approval of the Application.

10.0 ENVIRONMENTAL AFFAIRS

Staff reviewed the proposed project to determine whether it raised any environmental concerns that were not previously assessed as part of the *White Rose Oilfield Comprehensive Study Report*[1] completed in 2001, in the documents submitted by the Proponent in support of the new drill centres environmental assessment[2],[3], in the C-NLOPB's *New Drill Centre Construction and Operations Program CEA Act Screening*[4] or in C-NLOPB Decisions 2001.01, 2007.02, 2008.03.

It was determined that the development of the White Rose Extension Project (WREP) using a wellhead platform (WHP) required a separate environmental assessment. The WREP includes the construction of the WHP onshore at Argentia and installation of the WHP in the White Rose Field. The C-NLOPB conducted a screening level environmental assessment that satisfied the requirements of both the Newfoundland and Labrador *Environmental Protection Act*[5] and the federal *Canadian Environmental Assessment Act* (CEAA)[6]. The EA process that included a number of provincial and federal agencies, including Fisheries and Oceans Canada, Environment Canada, and Transport Canada as Responsible Authorities under the *Canadian Environmental Assessment Act*[7] was completed in September 2013.[8] The assessment concluded that, with the application of mitigation measures identified in the White Rose Extension Project Environmental Assessment[9] and Addendum[10], the implementation of a follow-up program and adherence to relevant C-NLOPB guidance material, significant adverse environmental effects associated with the project were not likely.

An agreement was reached between the C-NLOPB, as the Federal Environmental Assessment Coordinator (FEAC) for the Screening level EA, and the Newfoundland and Labrador Department of Environment and Conservation (NLDEC) that a single harmonized environmental assessment process could accommodate the Province's information and review process requirements. The scope of the provincial EA was confined to project details regarding the Argentia Peninsula and activities in Placentia Bay and required approval of the Minister of Environment and Conservation under Section 54 of the *Environmental Protection Act* and Section 7 of the *Environmental Assessment Regulations*[11]. The Minister of Environment and Conservation released the project on August 21, 2013 from further environmental assessment, subject to two conditions: submission of a Groundwater Monitoring Plan; and an amendment to the 2007 White Rose Expansion Project Framework Agreement to include benefit requirements for the WHP.

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[1] Husky Oil Operations Limited, *White Rose Comprehensive Study Report*, April 2001, 94 p.
[2] LGL Limited, September 2006, *Husky White Rose Development Project: New Drill Centre Construction & Operations Program Environmental Assessment*. LGL Rep. SA883. Rep. by LGL Limited, St. John's, NL, for Husky Energy Inc., Calgary, AB. 299 p. + Appendices.
[3] LGL Limited, January 2007, *Husky White Rose Development Project: New Drill Centre Construction & Operations Program Environmental Assessment Addendum*. LGL Rep. SA883a. Rep. by LGL Limited, St. John's, NL, for Husky Energy Inc., Calgary, AB. 126 p. + Appendices.
[4] C-NLOPB, April 2007, *Husky White Rose Development Project: New Drill Centre Construction and Operations Program, CEA Act Screening Report*, 38 p.
[5] *Environmental Protection Act,* SNL2002 CHAPTER E-14.2
[6] *Canadian Environmental Assessment Act*, S.C. 1992, c. 37
[7] *Canadian Environmental Assessment Act*, S.C. 1992, c. 37
[8] Canada-Newfoundland and Labrador Offshore Petroleum Board, Environment Canada, Fisheries and Oceans Canada and Transport Canada, September 2013, *White Rose Extension Project, Husky Oil Operations Limited White Rose Extension Project, Canadian Environmental Assessment Act (S.C. 1992, c. 37) Screening Report*, 78 p.
[9] Husky Energy, December 2012,*White Rose Extension Project Environmental Assessment*, , St. John's, NL,
[10] Husky Energy, July 2013, *White Rose Extension Project: Consolidated Response to Review Comments on the White Rose Extension Project Environmental Assessment and Addendum*, 226 p.
[11] *Environmental Assessment Regulations, 2003*, Newfoundland and Labrador Regulation 54/03.

The temporal scope of the proposed WREP, as described in the Application, extends beyond the temporal scope assessed in the 2001 *White Rose Comprehensive Study Report*[12] and the 2007 Screening Report for five additional drill centres[13]. The EA for the proposed WREP includes the temporal scope for installation, production and maintenance up to 2042, with decommissioning and abandonment after 2042.[14] The temporal scope of the original White Rose Comprehensive Study Report and the Screening Report for five additional drill centres extends to 2020. For activities assessed in 2001 and 2007, the C-NLOPB will not be able to issue authorizations beyond the temporal scope of those assessments. Where the WREP relies upon or is connected to assets previously assessed in 2001 or 2007, the Proponent will have to address temporal scope issues by amending the environmental assessment documents.

In reference to the WREP assets, the Proponent has stated that the WHP will be decommissioned and abandoned by first abandoning the wells in accordance with standard oil field practices, then decommissioning of the topsides, followed by decommissioning and abandonment of the CGS. The WHP will not be disposed of offshore nor converted to another use on site. Subsea wells will be decommissioned and abandoned in accordance with standard oilfield practices. The Proponent has stated that all equipment located in excavated drill centres will be removed and the drill centres will be left as they are. Xmas trees and manifolds will be purged, rendered safe and recovered. All other subsea facilities on or above the seafloor, including riser base manifolds, loading riser manifolds and flowlines, will be purged and decommissioned in accordance with regulations prevailing at the time. Flowline sections that have been rock-dumped will not be recovered, and will be cut by divers at the locations where rock dumping ceases. Rock berms are approved by DFO as compensation for fish habitat loss and removal may constitute a harmful destruction of fish habitat and as such, could require an authorization under the *Fisheries Act*. All risers and umbilicals will be decommissioned, rendered safe and recovered. At the time of decommissioning and abandonment, the Proponent will be expected to review its plans to ensure that they meet the environmental commitments made in environmental assessment documents and development plan applications.

Environmental protection plans (EPPs) currently exist for production operations on the White Rose Field using the *SeaRose FPSO*, and for drilling operations using MODUs. The Proponent will be expected to develop a facility-specific EPP for the WHP. The Proponent has committed to developing such a plan to be submitted with their operations authorization application for the WHP. Staff notes that the primary function of the WHP is drilling and that there will be no oil storage in the CGS. All well fluids will be transported via subsea flowlines to the S*eaRose FPSO* for processing, storage and offloading. In this regard, the submitted EPP will be required to describe all planned discharges from the WHP [as required by SOR/2009-316, subsection 9.(i)] , but the discharges are expected to be limited primarily to those associated with a drilling platform while the associated production related discharges will occur primarily at the *SeaRose FPSO*.

The Proponent plans to discharge water-based drilling fluids and cuttings overboard in a manner consistent with current drilling operations and C-NLOPB requirements. For drilling operations from the WHP using synthetic-based mud, the Proponent has committed to the re-injection of cuttings into dedicated disposal wells - pending confirmation of a suitable disposal formation. The Proponent's base plan is to drill two cuttings reinjection wells for cuttings disposal purposes.

In situations where the Proponent is unable to re-inject cuttings from SBM drilling operations, it has committed to a cuttings management and treatment process, including a secondary cuttings dryer system, to lower synthetic based mud on cuttings (SOC) to a target level of 6.9 percent SOC. In the period prior to implementation of CRI, and in the event of CRI system failure the alternative treatment process would be implemented prior to cuttings discharge overboard.

[12] Husky Oil Operations Limited, April 2001
[13] C-NLOPB, April 2007, *Husky White Rose Development Project: New Drill Centre Construction and Operations Program, CEA Act Screening Report*, 38 p
[14] Husky Energy, December 2012,*White Rose Extension Project Environmental Assessment*, , St. John's, NL

In the North Amethyst Development Application, the Proponent stated that it had "determined that environmental risk is more appropriately defined through a qualitative, rather than quantitative, assessment. The qualitative assessment provides a number of environmental objectives and provides protection measures to ensure these objectives are met." C-NLOPB staff was not persuaded that the Proponent's approach to environmental risk was appropriate, particularly since its environmental assessment report described a number of potential environmental risks in quantitative terms. In its review of this Application, C-NLOPB staff clarified that, because the likelihood of an environmental event of a specified class of magnitude (i.e. petroleum spill volume) was clearly described quantitatively in the environmental assessment documents, and because the discussion of effects on valued ecosystem components had been dealt with in a semi-quantitative way in the environmental assessment, the Proponent should refer to these documents, where appropriate, as providing the "target levels of safety" with respect to environmental events. In this regard, C-NLOPB staff required the Proponent to verify that probabilities of occurrence and risks associated with various environmental events described in the Development Plan Amendment Application and the Concept Safety Analysis were consistent with the same events and classes of events described in the Environmental Assessment for the project. The Proponent verified that the probabilities of occurrence and risks were consistent across the EA, DPA and CSA.

The Proponent has an ongoing Environmental Effects Monitoring (EEM) program to meet the Canadian Environmental Assessment Act requirements for a follow-up program. Two additional conditions related to EEM were incorporated into Decision Report 2007-02 related to the South White Rose Extension and Decision Report 2008-03 related to the North Amethyst Drill Centre. The Proponent's EEM program was revised accordingly and accepted by the C-NLOPB in 2010. Amendment of the program to account for the WREP is required as stated in the following conditions.

- **The Proponent will be required to submit to the Chief Conservation Officer, no later than 12 months prior to the scheduled commencement of offshore drilling activities associated with the Project, an amended Environmental Effects Monitoring (EEM) Plan design that incorporates drilling and production activities associated with the proposed activities, and tie-back to the *SeaRose FPSO*. The amended EEM Plan should be consistent with the strategy in the Husky EEM Design Report, discuss any changes that may be required to existing sampling stations, and consider the necessity for collection of baseline data at any or all of the new drill centre and CGS locations. Drilling operations associated with the Project will not be authorized until an acceptably amended EEM Plan is in place. Drill cutting dispersion model predictions will be validated in situ by monitoring the thickness of cutting piles on the seafloor once the White Rose EEM program is revised to accommodate operation of the WREP.**

- **The Proponent will be required, prior to commencement of offshore construction activities, to collect any field data required to inform the design of its EEM program.**

10.1 Recommendation

No environmental concerns were identified that would preclude staff from recommending approval of the Application. However, two conditions of approval are recommended relating to amendment of the Proponent's Environmental Effects Monitoring Plan as follows:

1. **The Proponent will be required to submit to the Chief Conservation Officer, no later than 12 months prior to the scheduled commencement of offshore drilling activities associated with the Project, an amended Environmental Effects Monitoring (EEM) Plan design that incorporates drilling and production activities associated with the proposed activities, and tie-back to the *SeaRose FPSO*. The amended EEM Plan should be consistent with the strategy in the Husky EEM Design Report, discuss any changes that may be required to existing sampling stations, and consider the necessity for collection of baseline data at any or all of the new drill centre and CGS locations. Drilling operations associated with the Project will not be authorized until an acceptably amended EEM Plan is in place. Drill cutting dispersion model**

predictions will be validated in situ by monitoring the thickness of cutting piles on the seafloor once the White Rose EEM program is revised to accommodate operation of the WREP.

2. **The Proponent will be required, prior to commencement of offshore construction activities, to collect any field data required to inform the design of its EEM program.**

APPENDICES

APPENDIX A: PUBLIC REVIEW REPORT

MEMORIAL
UNIVERSITY

Leslie Harris Centre of Regional Policy and Development

Memorial University of Newfoundland
St. John's, NL CANADA A1C 5S7
Tel: (709) 864-7963 Fax: (709) 864-3734 www.mun.ca/harriscentre

White Rose Extension Project: Public Review Process Report

Prepared for the Canada-Newfoundland and Labrador Offshore Petroleum Board

Keith Storey, PhD
Leslie Harris Centre for Regional Policy and Development
Memorial University, St. John's, NL

September 23, 2014

1.0 Background to the Public Review

Husky Energy intends to develop the western portion of the White Rose field and other potential resources (the White Rose Extension Project, hereafter the WREP), and has submitted an application to do so to the Canada-Newfoundland and Labrador Offshore Petroleum Board (the Board).

The Board is responsible for management and regulation of the petroleum resources in the Canada-Newfoundland and Labrador Offshore Area, pursuant to the Canada-Newfoundland Atlantic Accord Implementation Act, and the Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act (the Acts).

The C-NLOPB, in Decision 2001.01, approved the original White Rose Development Application. The reservoir depletion scheme in the original Development Plan contemplated the exploitation of oil resources in the western portion of the White Rose field. When the application to develop the western portion of the field came forward from Husky Energy, the Board decided that an amendment to the original White Rose Development Plan was required. Furthermore, with the significant benefits arising from the construction of a concrete gravity drilling structure in Argentia, NL, the Board decided that an amendment to the Benefits Plan was also required.

The Acts establish the requirements that proponents of offshore petroleum development projects must fulfill in order to obtain approval for a Development Application, including an amendment. The Development Application is primarily comprised of a Benefits Plan and a Development Plan with supporting documents.

Section 44(1) of the Accord Acts (Federal Version) states that:

> 44. (1) Subject to any directive issued under subsection 42(1), the Board shall conduct a public review in relation to any potential development of a pool or field unless the Board is of the opinion that the public hearing is not required on any ground the Board considers to be in the public interest.

The Board's interpretation of section 44(1) is described in its Development Plan Guidelines, which indicates that the scale and scope of the public review should be commensurate with the scale of the development and the degree to which new and innovative techniques and approaches are proposed.

The legislation indicates that a public review is to be conducted in relation to any potential development "unless the Board is of the opinion that the public hearing is not required on any ground the Board considers to be in the public interest". Therefore, the legislation contemplates that a public hearing may be necessary for some developments and not for others. In other words, the public review process is best determined on a case-by-case basis.

In respect of this Development Application Amendment, the Board decided that the form of the public review would be a 90-day web-based process, supplemented by public information sessions. It was also determined that the public review process would be conducted by an independent third party. The Leslie Harris Centre of Regional Policy and Development, Memorial University of Newfoundland (The Harris Centre), was selected to lead this process on behalf of the Board. The Harris Centre was to be responsible for the following:

- Establish and promote a website to solicit the public's input on the application;
- Post a description of the project on the website in a format and manner that is suitable for public understanding;
- Conduct public information sessions as may be required to further assist the public in understanding the project; and
- Provide a report within 30 days following the public review period.

This final report would then be considered in the Board staff's analysis of the Application.

The public review focused on four main documents:

- Benefits Plan Amendment
- Development Plan Amendment
- Socio-economic Impact Statement Update
- Wellhead Platform Concept Safety Analysis

The Public Review did not include a review of the environmental assessment of the project as prior to receipt of the Development Application, the WREP underwent a harmonized environmental assessment (EA) process that satisfied the requirements of both the Newfoundland and Labrador Environmental Protection Act and the federal Canadian Environmental Assessment Act (CEAA).

The NL Minister of Environment and Conservation determined on August 21, 2013 that the EA was satisfactory and released the project from further environmental assessment, subject to conditions as published. The C-NLOPB, Fisheries and Oceans Canada, Environment Canada, and Transport Canada, as Responsible Authorities under the CEAA, determined on September 18, 2013 that, following the application of mitigation measure, the WREP was not likely to cause significant adverse environmental effects.

These decisions were based on information provided by Husky Energy in the *White Rose Extension Project Environmental Assessment* and in the company's *Response to Review Comments on the White Rose Extension Project Environmental Assessment*. The latter two documents are intended to fulfill the requirement for an Environmental Impact Statement within the Accord review. This EA process included an opportunity for public comment, and all documents related to this process are posted on the C-NLOPB's website at (http://www.cnlopb.nl.ca/environment/whiterose.shtml).

2.0 The WREP Public Review Website

2.1 Website

A website for the White Rose Extension Project Public Review was established at www.whiteroseconsultation.ca. The site was organized into three main areas to facilitate participation by the public in the review process:

- Get informed by:
  - Reading FAQs about the project, the process and the players;
  - Reading the Project Summary document;
  - Attending an information session; and
  - Viewing a presentation.
- Review the Application documents:
  - Benefits Plan Amendment
  - Development Plan Amendment
  - Socio-economic Impact Statement Update
  - Wellhead Platform Concept Safety Analysis
- Have your say by:
  - Asking a question
  - Commenting on the Application documents
  - Submitting a written submission

Information on the home page of the website also included a brief information video about the project, details of the Public Information Sessions, presentation slides from the information sessions, contact information for the Harris Centre, links to received formal submissions and information on the end date of the Public Review period. Site visitors could also request hard copies of any of the documents under review.

To ensure appropriate use of the site, Terms of Use, Privacy Policy, Moderation, Accessibility and Technical Support details were included on the home page (see http://whiteroseconsultation.ca).

2.2 Registration

While anyone could view any of the content on the website, request hard copies of documents or ask a question, those wishing to participate in discussion about the development application amendment documents were asked to register using an email address, a user name and a password. As per the terms of use and privacy policy of the site, users were only ever identified publicly by their user name, which could be a pseudonym.

2.3 Questions

Visitors to the website could ask questions about the project or the regulatory process via a specified form. Questions asked were directed to either Husky or the C-NLOPB, as appropriate, for response. Every effort was made to post an answer to questions asked within three business days. Questions or answers with any private or identifying information were kept private. Participants preferring their question to remain private could also request this. Otherwise all questions and answers of general public interest were posted on the website.

2.4 Comments

Registered users of the website could also provide comments on specific subject matter in the individual documents via discussion, e.g. comments related to employment would typically be made under the Benefits Plan Amendment. Users could also indicate their agreement or otherwise with the posted comments of others.

If comments bridged more than one subject area and document, comments could be cross-referenced, e.g. comments on safety might be cross-referenced in both the Wellhead Platform Concept Safety Analysis and the Development Plan.

All comments were subject to the site terms of use, privacy and moderation policies, which included third party screening for obscene or abusive comments as well as review for relevance. In cases where comments were deemed irrelevant, or out of the scope of the public review process, the site administrators could indicate such in a reply to the comment on the site.

2.5 Website activity summary

In total 4,352 persons visited the website during the consultation period and 501 document downloads occurred. Two interested groups submitted detailed comments and recommendations and there were four comments from private individuals.

Members of the public had the opportunity to ask questions and post comments confidentially. There were two requests for confidentiality with respect to questions, but there were no comments that participants requested be kept private. The private questions and responses have been submitted to the C-NLOPB separately from this report.

3.0 Public Information Sessions

Four Public Information Sessions were held as part of the review process, in Placentia at the Arts Centre on June 24, 2014, at 2 pm and 7 pm, and in St. John's at the Holiday Inn on June 25 at 2 pm and 7pm. The 7pm St. John's session was also webcast live and an audio recording of that webcast, together with the presentation slides used at the information sessions, were posted on the website.

The sessions were publicized beforehand with newspaper advertisements in *The Telegram* on June 14 and by radio on Steele Communications stations VOCM (AM Station) and K-Rock 97.5 (FM Station). Information about the review process and the Public Information Sessions were also circulated through the Noia daily e-bulletin. A public service announcement on the public information sessions was submitted to the local community channel for the Placentia area.

Each of the Public Information Sessions was scheduled for two hours. The format for each was as follows:

- Welcome, safety moment and housekeeping issues and introduction of session facilitator Keith Storey, by Morgan Murray on behalf of the Harris Centre;
- Outline of the public review process and the role of the Harris Centre, information on accessing and using the website, the purposes of the sessions and introduction of Husky Energy WREP project presented by Keith Storey;
- Overview of the WREP by Richard Pratt, Vice President, Developments, Atlantic Region, Husky Energy and Derek Pearcey, Graving Dock/CGS Project Manager, Husky Energy (their joint presentation lasted approximately one hour);
- Question and answer session, facilitated by Keith Storey with questions responded to by Richard Pratt, Derek Pearcey and other members of the Husky Energy WREP team attending the session; and
- Session closing and reminder by Keith Storey to those participating to submit their comments via the website within the 90-day review period window.

At the conclusion of the formal proceedings for each session Husky Energy representatives made themselves available for further discussion with members of the public.
A record of the questions and comments made at the Public Information Sessions was maintained by Harris Centre staff for subsequent inclusion on the website and in the final report.

Attendance at the sessions was generally light, with 18 and 7 members of the public attending the two Placentia sessions and 37 and 16 people attending the St. John's sessions.

Questions and comments at the Placentia sessions focused primarily on local (i.e., Placentia area) issues, such as employment and business opportunities, traffic concerns and local corporate funding support.

In St. John's, questions and comments were concerned mainly with topsides project employment opportunities, sub-contractor business opportunities, cost and timeline estimates, offshore personnel transfer arrangements, projected exploration activity levels, and worker training plans.

Concerns and comments from the Public Information Sessions are included in the Summary of Concerns, Comments and Submissions, Section 5.0.

4.0 Ongoing Review Process Publicity

To maximize potential public involvement in the review process email reminders encouraging comments on the project and the application documents under review were sent out on July 23, 2014, to 19 groups/organizations that were considered likely to have an interest in the project. The notice sent read as follows:

> Good Day,

This email is to advise that the deadline for comments as part of the public review period for Husky Energy's proposed White Rose Extension Project is **September 10, 2014**.

The 90-day public review period is part of the Canada-Newfoundland and Labrador Offshore Petroleum Board (CNLOPB) review of the proposed White Rose Extension Project and this is being coordinated by the Leslie Harris Centre of Regional Policy and Development at Memorial University. Your input and comments are welcome. To learn more about the proposed project, review the application documents and to have your say, please visit www.whiteroseconsultation.ca. All comments must be received by **September 10, 2014**.

Please feel free to forward this message to your membership, affiliate organizations or others that you believe may have an interest in the proposed project.

Regards,
Dr. Keith Storey,
Chair, Public Review Process
Harris Centre

A second, similar, email reminder was sent out to 17 of the 19 groups/organizations on August 28, 2014[15], emphasizing the closing date for comments and submissions. In addition:

- The WREP website was updated on August 27 2014 to highlight the end of the consultation period on September 10 2014;
- An advertisement ran in the *Telegram* September 3, advising of the end date of the consultation period;
- NOIA circulated information about the end of the consultation period on September 8, 2014 through its daily ebulletin; and
- A public service announcement drawing attention to the end of the consultation process was submitted to the community cable channel for the Placentia area.

5.0 Summary of Concerns Comments and Submissions

5.1 Introduction

Concerns, comments and submissions posted on the website are organized here by relevance to primary document, e.g., Benefits Plan Amendment, Socio-economic Impact Statement Update, etc., and by theme, e.g. business, employment issues, etc.

Some questions asked at the public information sessions that expressed no particular concern, but were asked purely to acquire additional information, are not included in this summary. It should be noted that this is a *summary* of concerns and submissions. Readers

[15] One group made a submission in the intervening time period, the email address for another was inactive and no alternative address could be found.

are encouraged to access the concerns comments and submissions, and in some cases responses, as presented on the website for further details.

Concerns, comments and submissions by document relevance and theme are summarized below with the source (where self-identified) of the concern/comment indicated:

5.2 Benefits Plan Amendment

5.2.1 Business Concerns

5.2.1.1 Technology Transfer and Research and Development

The Benefits Plan Guidelines anticipate continuous improvement in technology transfer and research and development. In the original White Rose Benefits Plan Husky stated that it would develop strategies to achieve its objectives in this regard. Noia recommends that the C-NLOPB require Husky to provide information on these strategies, including the objectives, progress, measurement metrics employed and how this commitment has addressed the expectation for continuous improvement. (Noia)

5.2.1.2 Supply Constraints

The Benefits Plan Amendment is seen as providing adequate information on supply opportunities in both the construction and operations phases of the project, but does not fully address constraints. Noia recommends that the C-NLOPB require Husky to provide further information on supply constraints. (Noia)

5.2.1.3 National and International Business Participation

The proponent is expected to have programs, policies or procedures to enable Newfoundland and Labrador and other Canadian suppliers to participate in the proponent's national and international activities. The amendment does not specifically address this expectation and Noia recommends that the C-NLOPB require it to be specifically addressed within a program with clearly defined objectives. (Noia)

5.2.1.4 Canada-Newfoundland Benefits as an Evaluation Criterion

Husky states Canada-Newfoundland Benefits will be a factor in awarding all contracts. Noia strongly supports Husky's use of the evaluation criteria (supplier development, research and development (R & D), and technology transfer, NL content and person-hours, ownership and training) for Canada-NL benefits and is interested in how the evaluation has influenced results.

The proponent is also expected to have plans for transfer of technology and "know- how" to Newfoundland and Labrador and other Canadian suppliers and contractors.
Husky has clearly expressed its belief in the value of technology transfer and has outlined the requirement for contractors and that bidders will be rewarded for proposals that detail innovative initiatives, strategies and methods for transfer of technology. Noia is supportive of Husky in this and believes that effective technology transfer can produce positive results.

Noia recommends the C-NLOPB require that Husky demonstrate how the evaluation criterion has contributed to achieving positive and measurable results for Canada-NL Benefits. (Noia)

5.2.1.5 International Competitiveness

The C-NLOPB encourages offshore proponents to undertake initiatives that will assist business firms in the province to become internationally competitive in the offshore oil and gas industry. Husky states that it *'provides support and assistance to bidders through early notification of program requirements and specification and encouragement of Newfoundland and Labrador suppliers to become globally competitive – including the provision of technical assistance and advice where necessary'.* Noia supports and encourages Husky to continue with this initiative and recommends that the C-NLOPB require Husky to describe how encouragement, technical assistance and advice will be provided for the WREP. (Noia)

5.2.1.6 Newfoundland and Labrador Fabrication, Outfitting and Other Commitments

Section 3.0 of the Benefits Plan Amendment, states that *'This Benefits Plan Amendment also takes into consideration the 2013 White Rose Expansion Project Framework Amending Agreement with the Government of Newfoundland and Labrador*', but does not detail the commitment (packages) for mechanical fabrication and mechanical outfitting in Newfoundland and Labrador or other aspects of the commitments such as for the additional sub-sea facilities, infrastructure and temporary works and detailed and construction engineering. Noia recommends that the C-NLOPB require Husky to provide detail on all the NL commitments in the 2013 Amending Agreement in Table 5.1 and that these be identified for NL only. (Noia)

5.2.1.7 Integrated Drilling And Utilities Module

Information on the Integrated Drilling and Utilities Module (bid internationally as per the Amending Agreement) is absent from Table 5.1 and Noia recommends that the C- NLOPB require Husky to include this information. (Noia)

5.2.1.8 Global Frame Agreements

Noia is concerned about the use of global frame agreements and the potential impact on local supply, in particular during the operations phase. In this regard Noia recommends that the C-NLOPB require Husky to identify its plans for the control of this type of agreement and encourage Husky to not use frame agreements that would negatively impact local suppliers. (Noia)

5.2.1.9 Employment and Business Diversity

Husky believes that an effective employment and business diversity strategy is important to the successful development of the Newfoundland and Labrador offshore oil and gas industry. Noia is supportive of this belief and commends Husky on its Diversity Plan and goals for the access of designated groups to employment and training on the Project.

Noia is also supportive of supplier diversity and recommends that the C-NLOPB require Husky to include special measures to facilitate the increased and measurable participation of under-represented groups in procurement for the project in both the development and operational phases. (Noia)

5.2.1.10 Small Company Participation

Noia is concerned that opportunities for smaller companies to participate in the project are limited unless measures are undertaken.

Noia recommends that the CNLOPB require Husky to develop special proactive measures including policies or procedures for sub-contracting to facilitate the increased participation of small companies in procurement for the project in both the development and operational phases. (Noia)

5.2.1.11 Business Targets for Women

The Business Access portion of the Diversity Plan is seen to require more information on how women and other designated groups might access business opportunities from the Project. Questions posed include:

- How does the Project plan on achieving the business access piece for women?
- What will constitute a woman or women owned/controlled business?
- Will there be a certification process?
- What targeted and proactive measures will be taken to ensure women specifically are aware of business opportunities and how to competitively access them?

The Provincial Advisory Council on the Status of Women (PACSW) strongly recommends targets for business access for women. Husky is encouraged to review the Hebron Supplier Diversity Program in this regard.

Elements of a Business Access plan, specific to women, would include:

- The opportunity for women-owned businesses to self-identify;
- A certification program for women-owned businesses in line with national certification programs;
- Identification of where current business access exists;
- Communication of information on supply and procurement opportunities;
- Identification of possible barriers in the procurement program that limit potential participation; and
- Development of a business access strategy that provides a fully equitable supplier and procurement process.

It was also recommended that the business access strategy proposed to provide an equitable supplier and procurement program would include the following information:

- Positive policies and practices, including setting targets, raising awareness, training procurement officers and providing other supplier development supports for women and other designated groups to ensure their participation and benefits from supply and procurement;
- The identification of other aggressive and proactive measures to remove supply and procurement barriers for women-owned businesses and other designated groups;
- The identification of timetables and goals that are sufficient to achieve reasonable progress towards a representative supplier clientele for the project;
- A commitment and demonstration to continuous improvement;
- A commitment to and a demonstration of reasonable efforts to implement its plan and monitor, review, and revise its plan on an annual basis, including the assigning of responsibilities for this goal, and
- A commitment to prepare an annual public report by designated group that would include a report on the achievement of targets by procurement categorizes.

Initiatives, such as consulting with the Newfoundland and Labrador Association of Women Entrepreneurs and other local business networks are supported and encouraged. (PACSW)

5.2.1.12 Management and Maintenance of the Graving Dock

Noia believes that the new Graving Dock is a critical piece of infrastructure that can and should play an important and diverse role in the future. In this regard, Noia recommends that the C-NLOPB ask Husky to provide detail on what will remain at the site after construction of the CGS is complete. As well, Noia is concerned about the uncertainty regarding the future management and maintenance of the facility and recommends that the C-NLOPB ask Husky to provide greater definition on its future management and maintenance. (Noia)

A similar question was asked at the Placentia Information Sessions.

How will the dry dock or other project infrastructure help the long-term future of the Placentia area? Who will own the dry dock in the future?

Husky responded to this question as follows:

- Husky leases the CGS site from the Argentia Management Authority, but it would be premature to speculate on long-term use of the site at this point in the project.
- The reusable dock gates represent a significant up-front investment, and will allow for the future use of the site.

5.2.1.13 Bid Process for the CGS Contract

A participant at the St. John's Information Sessions, and later through the website, considered that there was a failure by CGS bidders to fully engage the supply community during the bidding stages. He recommended that the successful CGS bidder undertake a more exhaustive supplier development process to explain contracts and engage suppliers one-on-one. (R. Strong)

5.2.1.14 Business Opportunities for the Placentia Area

Several participants at the Placentia Information Sessions were concerned about the capture of local area benefits from the Project as follows:

- How does project information come to Placentia and surrounding towns?
- Some thirty companies are now supplying various things to the project. How can Placentia area companies take best advantage of such opportunities?
- What encouragement can we in the Placentia area expect from Husky to ensure that Placentia benefits from the project?
- How can we get the opportunity to provide services to those companies?
- How do we get information about contractors that will be working on the project in the Placentia area?

Husky Energy responded as follows:

- Project information is available at http://wrep.huskyenergy.com, at events such as the Placentia Bay Industrial Showcase, and the project Information Office at the Placentia Mall;
- The best way to stay involved and take advantage of all opportunities is to reach out to companies listed on the website and stay informed through supplier information sessions;
- Husky Energy cannot direct companies to use Placentia area suppliers. The Atlantic Accord has specific requirements regarding the provision of full and fair opportunity to businesses throughout Newfoundland and Labrador, not just those in the Placentia area. Husky encourages all businesses in the Placentia area to contact the prospective CGS contractors and to attend upcoming supplier information events.
- Potential suppliers should review the website to understand the main project contracts, and how they can fit into the supply chain.
- Husky's website is the best source of information for the project, and major contract award information is distributed through the Noia newsletter.

5.2.1.15 Helicopter Services

A participant at the St. John's Information Sessions wanted to know which company would provide helicopter services to the platform, the type of helicopter to be used and whether there would be any pooling of helicopter transportation with other offshore companies.

Husky responded as follows:

- The bidding process for a helicopter transportation provider is ongoing. The type of airframe and whether or not there would be pooling is yet to be determined.

5.2.1.16 Cost Overruns

A participant at the St. John's Information Sessions asked if the original projected costs for the project had changed and how cost pressures might be mitigated in the future.

Husky responded as follows:

- Bids for major contracts are still being examined and projected versus actual costs cannot be commented on at this time;
- Husky is well aware of the cost pressures on a project of this scale, which is why careful planning and execution are so important.

5.2.1.17 Use of the *West Mira* Drilling Unit

A participant at the St. John's Information Sessions wanted to know if the use of the West Mira drilling unit would mean a decrease in the use of older drilling units currently in use offshore.

Husky responded as follows:

- When it arrives, the *West Mira* will become the primary mobile offshore drilling unit for our operations in the region, but we may also contract additional drilling capacity as required;
- At present, the contract with the Henry Goodrich is scheduled to expire early 2015, and the contract for the GSF Grand Banks is scheduled to finish in September 2015.
- Future drilling contracts will be based on our anticipated drilling requirements, potential rig share opportunities, and the availability of drilling units, which are suitable for our offshore operating conditions.

5.2.2 Employment Concerns

The Provincial Advisory Council on the Status of Women noted that they are encouraged by Husky's commitment to: endeavouring to provide women, Aboriginal people and people with disabilities, an inclusive and culturally sensitive work environment; provide opportunities to advance their careers; provide assistance to employees in balancing the responsibilities of career and family life; and ensuring that the recruitment and selection process supports diversity. (PACSW)

5.2.2.1 Employment of Women - General

A low/zero representation of women in many occupational categories (e.g. marine crews, technicians/technologists) is noted. Recognition is given to the fact that there have been increases in some areas, but that there is still work to be done to increase the employment of women in the White Rose Project labour force during both the construction and operations phases. (PACSW)

5.2.2.2 Employment Targets for Women

Targets for employment of women are in part based on outdated information (2006 NOC code data). Targets based on outdated information are considered to help perpetuate women's low (or lack of) participation in many relevant occupational categories.

That said, targets were also based on recent labour market outlook views, which recognize the potential role of under-represented groups, including women, in helping meet future labour demands, on more recent data on achievements in provincial professional and vocational training programs and on information from agencies and groups representing women's interests. These perspectives and achievements need to be considered when developing realistic targets for women.

While targets have been established for the construction phase, PACSW recommends that targets also be established for the operational phase. (PACSW)

5.2.2.3 Offshore Apprentice Program

Providing an offshore apprentice program for women is seen as helping break down barriers they face where trying to gain experience offshore. This is seen by PACSW as a very positive commitment by Husky. (PACSW)

5.2.2.4 Newfoundland and Labrador Workforce Opportunities

The Business Manager of UA Local 740 Plumbers and Pipefitters expressed concern both at the Information Sessions and on the website about the small amount of topsides work being undertaken within the province and whether mating, hook-up and commissioning would utilize local workers.

Husky responded to the questions posed at the Information Sessions as follows:

- There were no yards available in the province at which to build the integrated module.
- The work was bid both internationally and in Newfoundland and Labrador so that any company wanting to compete for the work could do so.
- To maximize potential NL content certain components of the module were broken out for fabrication in the province.
- The crew in the field mating the topside with the CGS is expected to be made up mainly of the eventual full-time crew for the platform, of whom approximately 90% are anticipated to be Newfoundlanders and Labradoreans.

5.2.2.5 Training Programs

A participant at the Placentia Information Sessions asked if there would be training programs at existing facilities in the Placentia area or if new centres would be established.

Husky responded as follows:

> The training programs are something that will be worked on with the CGS contractor. The training programs are meant to help meet the immediate needs of the project through the local workforce, so until a contractor is selected, it is difficult to determine what those needs may be. In any event, it is expected that existing facilities would be

utilized, if possible.

5.3 Development Plan Amendment

5.3.1 Produced Gas

A participant at the St. John's Information Sessions asked how much gas would be produced and if that gas would be re-injected.

Husky responded as follows:

- 20 of the 38 wells will be oil producers. At this time, gas will be re-injected to enhance oil recovery and will also be used as a fuel source for the platform. Natural gas development is very important to Husky, but it is not the focus of the White Rose Extension Project.

5.3.2 Decommissioning

A participant at the St. John's Information Sessions asked if a Decommissioning Plan was required as part of the approval process.

Husky responded as follows:

- Our design incorporates the ability to decommission the facility.

5.4 Socio-economic Impact Statement Update

5.4.1 Social Concerns

5.4.1.1 Road Transportation

Three participants at the Placentia Information Sessions were concerned about impacts of traffic on the Placentia area:

> How do you intend to access the construction site at the Base? Will you be using the Dunville Road or are you considering building a separate road?
>
> Have you done any studies, or do you plan to do any studies on the impact that the project will have on traffic in the area, particularly the Dunville road? Is there anything that can be done to mitigate traffic effects?
>
> There is going to be a lot of traffic in and out of the construction site and the roads here are pretty bad. Are you going to be involved in any road works?

Husky Energy responded to these as follows:

- The Dunville Road will be used.
- No traffic studies have been done or are planned.
- The traffic situation in Dunville will be monitored.
- Husky Energy does not fund municipal infrastructure.

5.4.1.2 Childcare

When working or re-entering the workforce women often have difficulty obtaining affordable, reliable and flexible childcare options. Husky's commitment to collaborate with the Department of Child, Youth and Family Services in identifying an appropriate non-profit group to provide funding to explore child care issues of those working on large construction projects and possible responses is strongly supported by PACSW. (PACSW)

5.4.1.3 Support for Non-profit Organizations

A participant at the Placentia Information Sessions asked what help Husky is able to offer local non-profit organizations.

Husky responded as follows:

- Every year, Husky supports a number of charitable and community initiatives in the areas where we live and operate.
- Our funding priorities for community investment focus on health, education and community initiatives.
- http://www.huskyenergy.com/socialresponsibility/communityinvestment/default.asp provides organizations with all the information on what we do (and don't) fund, as well as the online application to apply for funding.

5.5 Wellhead Platform Concept Safety Analysis

There were no concerns or submissions relating to this document.

APPENDIX B: GEOLOGICAL MODELLING OF WEST POOL

Geological Modelling of West Pool

Board staff constructed a detailed 3D geological model for the West Pool using Petrel E& P Software Platform, version 2013.5. The model was constructed to estimate the in-place hydrocarbon resources and also to create a starting model for reservoir simulation. This model incorporated available geophysical, petrophysical, geological and reservoir engineering data.

The structural framework for the model is based on the fault and surface interpretation supplied by the Proponent. The model is confined vertically by the top Ben Nevis and the Mid-Aptian unconformity, and is subdivided by stratigraphic surfaces interpreted from well log and core data. Stratigraphic zones were further subdivided by proportional layering. The Board's West Pool model consists of a total number of 4149660 3D grid cells with and average grid cell size of 51 m x 53 m x 1.95 m.

Core data and available literature on the Ben Nevis Avalon (BNA) Formation were used to determine depositional environments (Figure B.1) and lithofacies (Figure B.2) within the West Pool. At each well location, lithofacies and associated depositional environment interpretations were correlated with the log data in the cored intervals and then predicted through the reservoir interval along the well trajectory, based on log response at the uncored sections. Depositional environment interpretations were upscaled at the well to the 3D grid and the model was populated using a sequential Gaussian simulation algorithm. Likewise, the lithofacies interpretation was upscaled to the 3D grid. The statistical population of the lithofacies model was conditioned to the depositional environment model for each facies and zone, and populated using sequential Gaussian simulation.

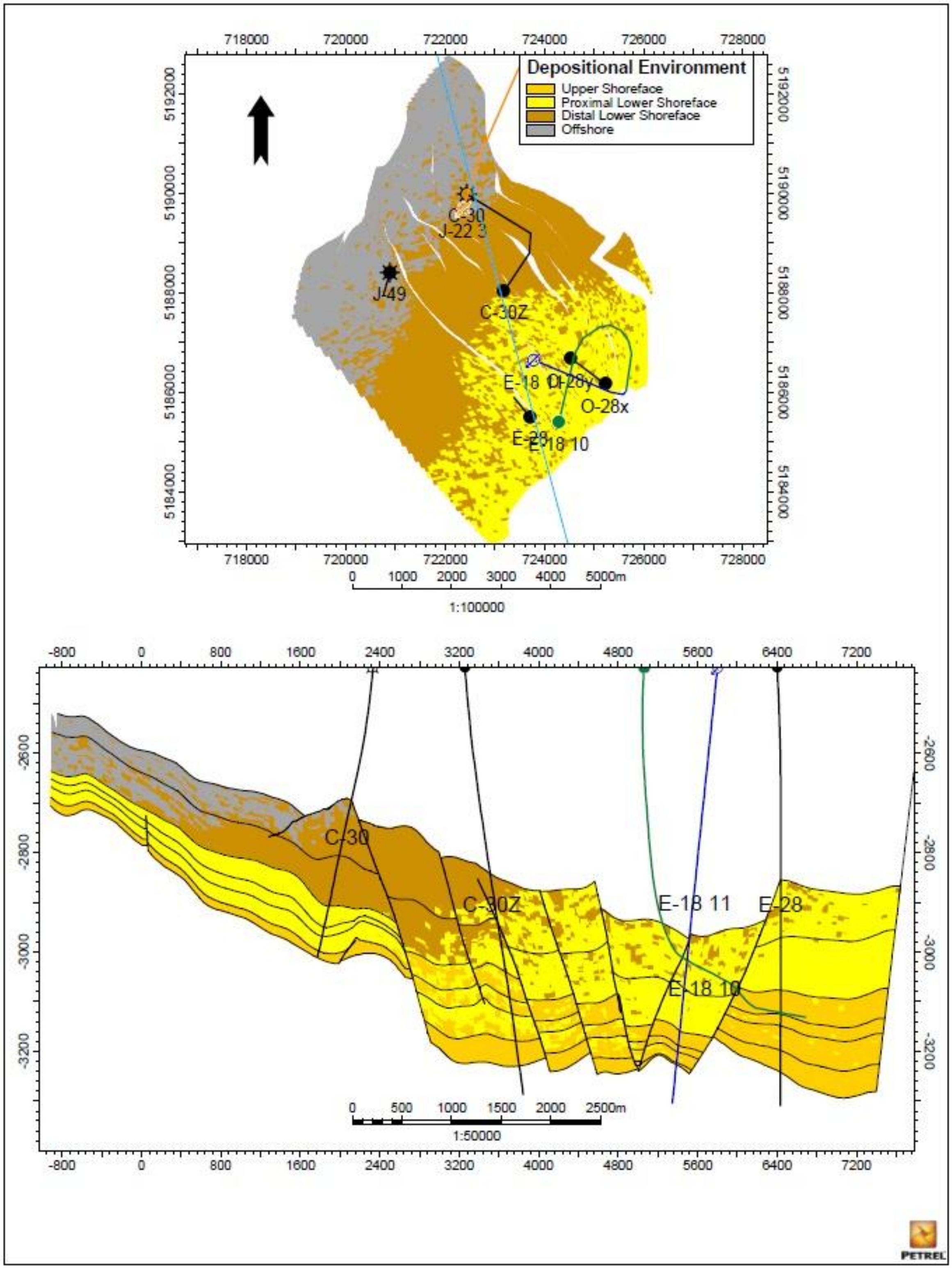

Figure B.1: Depositional environment of the West Pool region.

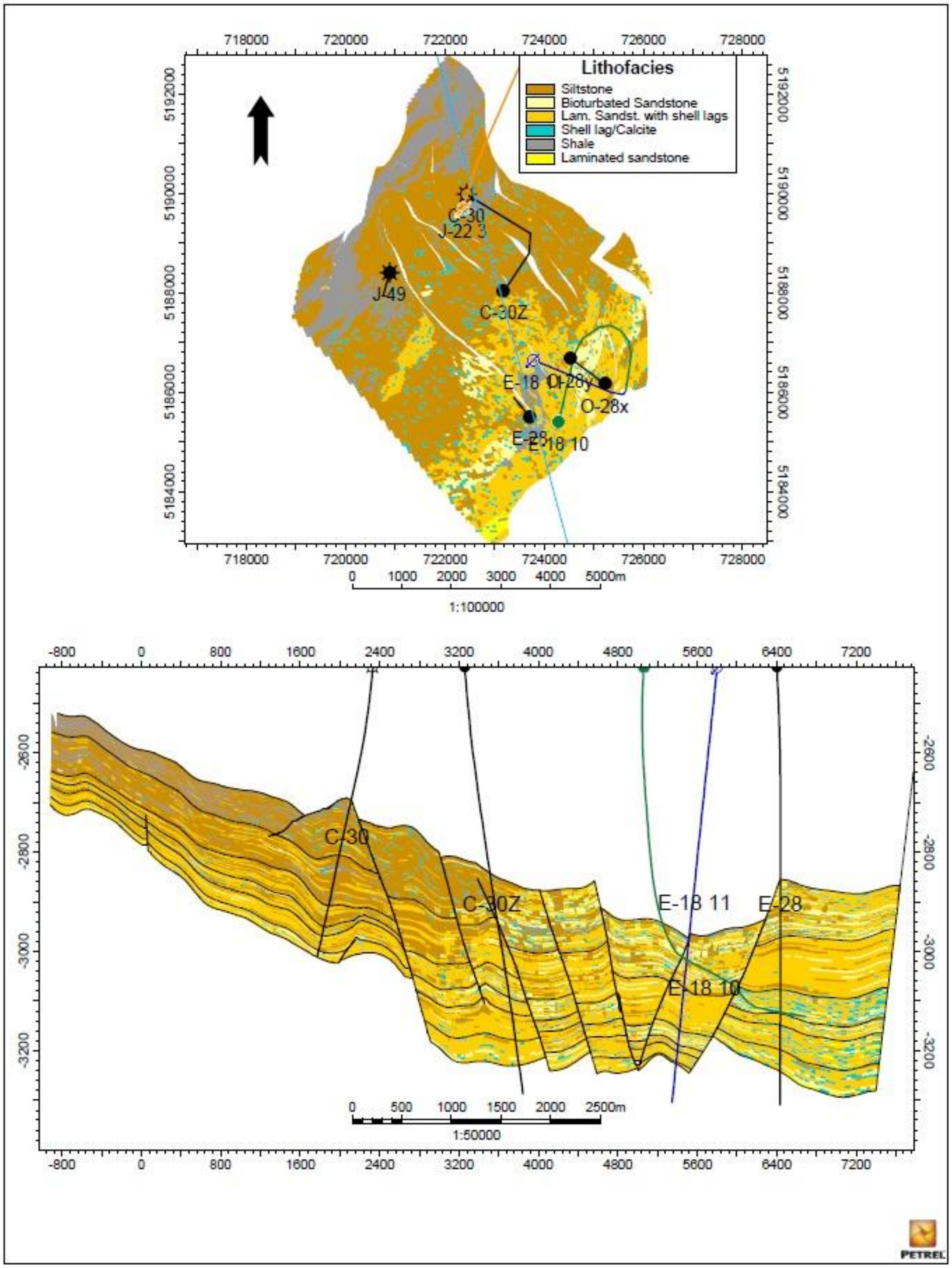

Figure B.2: West Pool facies model.

The hierarchical method for the West Pool model was performed which allowed the statistical populations of petrophysical data to be conditioned to the depositional environment and facies interpretations. The process of property modelling included upscaling porosity, water saturation, and permeability into the 3D grid and using Data Analysis to analyze the statistical distribution of the data by zone and facies (Figure B.3).

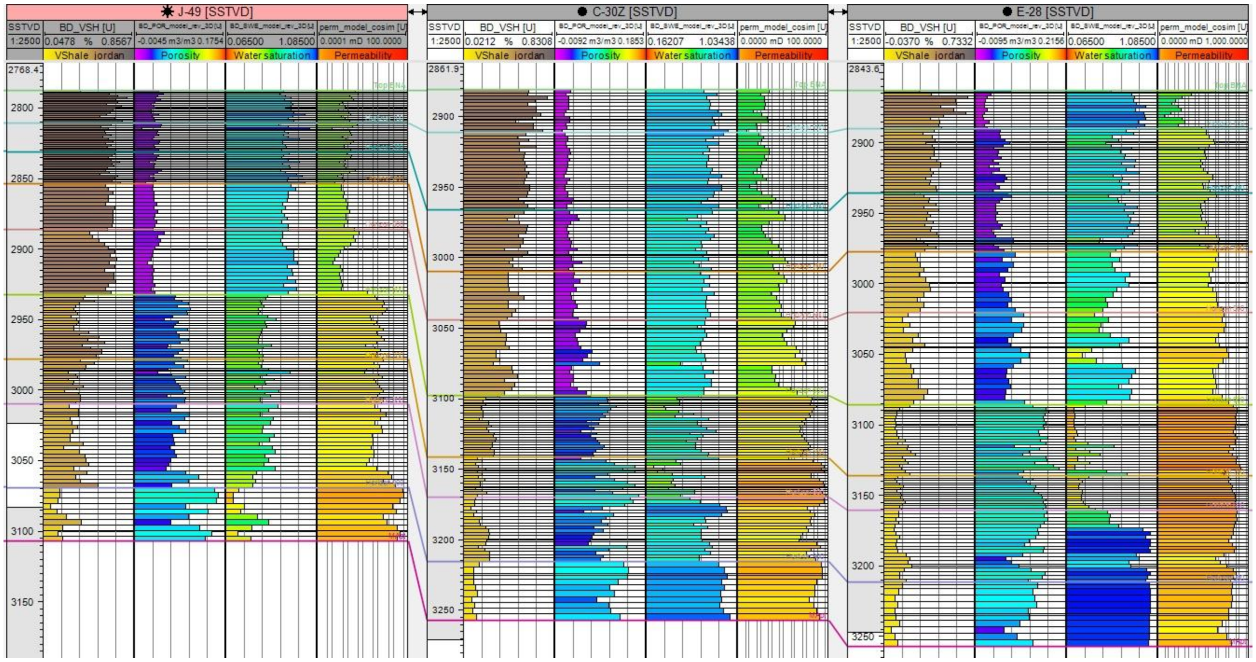

Figure B.3: Example of upscaled petrophysical parameters (Vsh, ϕ, Sw, K) for selected West Pool wells.

Upscaled porosity data were conditioned to the lithofacies model and populated through the grid using sequential Gaussian simulation. Water saturation data were upscaled to the grid, distributed through the 3D grid using a sequential Gaussian simulation algorithm, and co-kriged to the porosity model.

A power function was applied to the porosity property model using the property calculator to estimate a permeability model. The upscaled cells were extracted from the permeability model and co-simulated with the porosity model using collocated co-kriging in the Gaussian random function simulation property modelling method.

Board staff used the resulting deterministic hierarchical geological model as a basis for the stochastic assessment of the in-place hydrocarbon resources in the West Pool. Multiple parameters were varied during the evaluation, including lithofacies, porosity, water saturation, shrinkage and hydrocarbon contacts (Figure B.4).

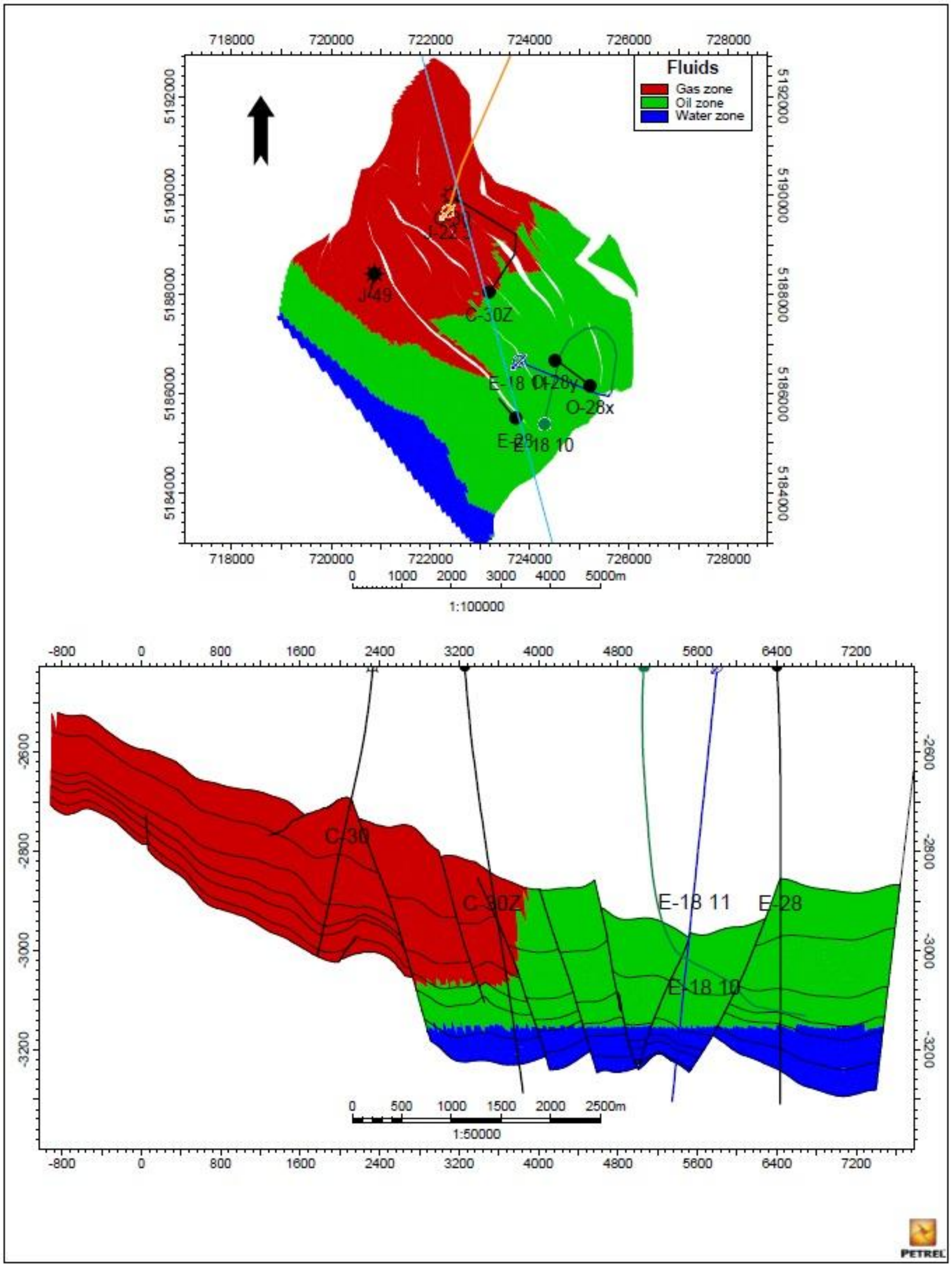

Figure B.4: West Pool fluid contacts.

A comparison of the Proponent's and the Board's probabilistic in-place resource estimates (P90 downside case, P50 most likely case, P10 upside case) for the West Pool is shown in Table B.1. These are volumetric stock-tank-original-oil-in-place (OOIP), original-gas-in-place (OGIP) (gas cap) and original-gas-in-place (OGIP) (solution). Hydrocarbon pore volume gas and oil maps are shown in Figure B.5 and Figure B.6.

Table B.1: Comparison of probabilistic in-place hydrocarbons for the West Pool region.

STOOIP ($x10^6$ m^3)	**P90**	**P50**	**P10**
Proponent	50.5	72.9	94
CNLOPB	118	133	151
GIIP(Free) ($x10^9$ m^3)	**P90**	**P50**	**P10**
Proponent	10.2	14.5	19.7
CNLOPB	19.2	21.8	24.5
GIIP(Solution) ($x10^9$ m^3)	**P90**	**P50**	**P10**
Proponent	6.1	8.7	11.4
CNLOPB	15	17	19

Overall, there is a discrepancy between the Proponent's and the staff's volumetric assessment. Differences between the Proponent's and staff's STOOIP and OGIP estimates are attributed to variations in geological and reservoir modelling approaches, petrophysical analyses and parameters varied in the uncertainty analysis. However, Board staff also ran a base-case volumetric assessment scenario applying the NTG cutoffs in Table B.2. The NTG filter applied to the fluid contacts region (Figure B.4) is shown in Figure B.7. The results in Table B.3 are comparable to the P50 results provided by the Proponent in the Application (Table B.1). Hydrocarbon pore volume gas and oil maps with the NTG considered for the region are shown in Figure B.8 and Figure B.9.

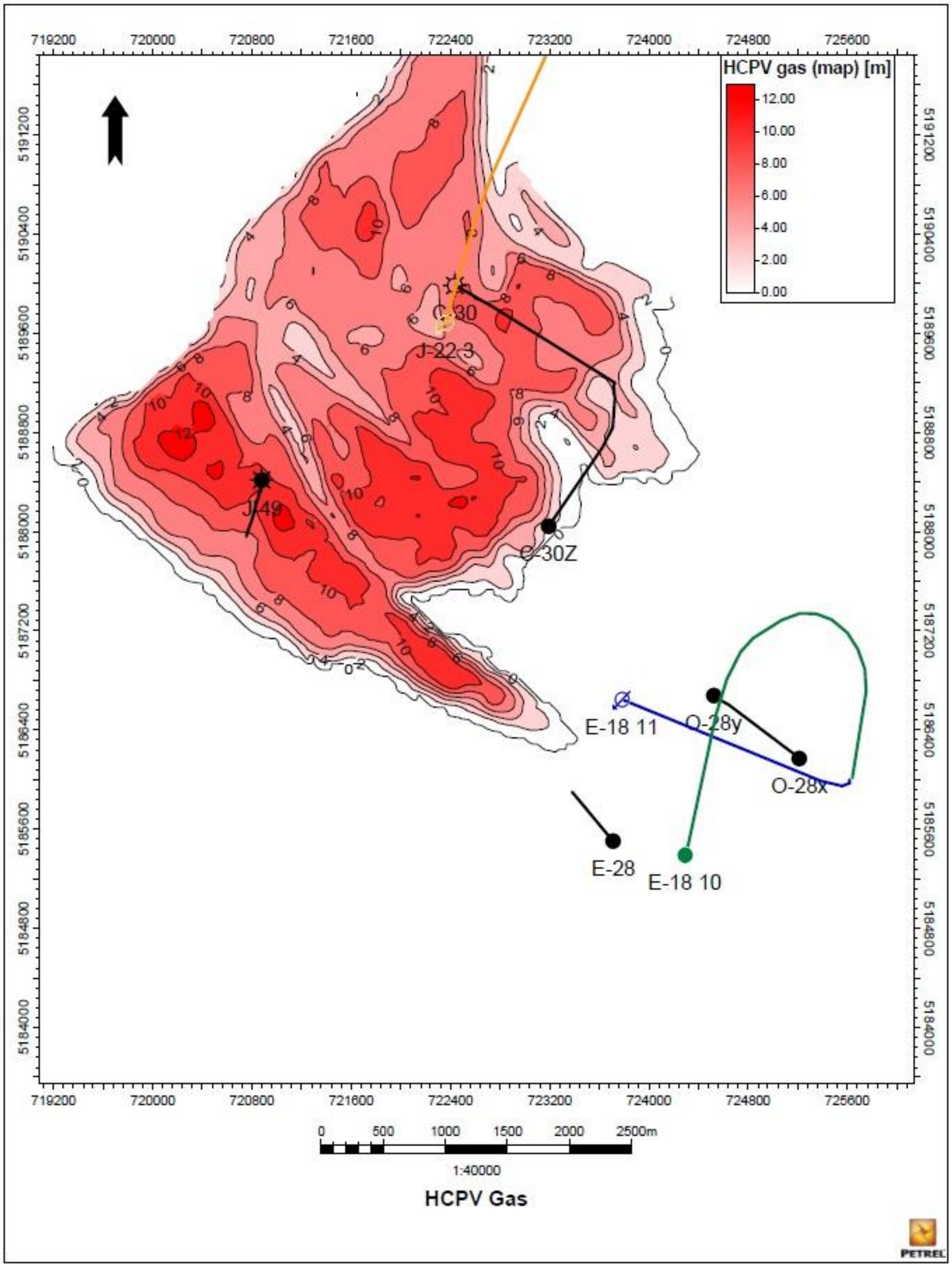

Figure B.5: Hydrocarbon pore volume of gas for the West Pool.

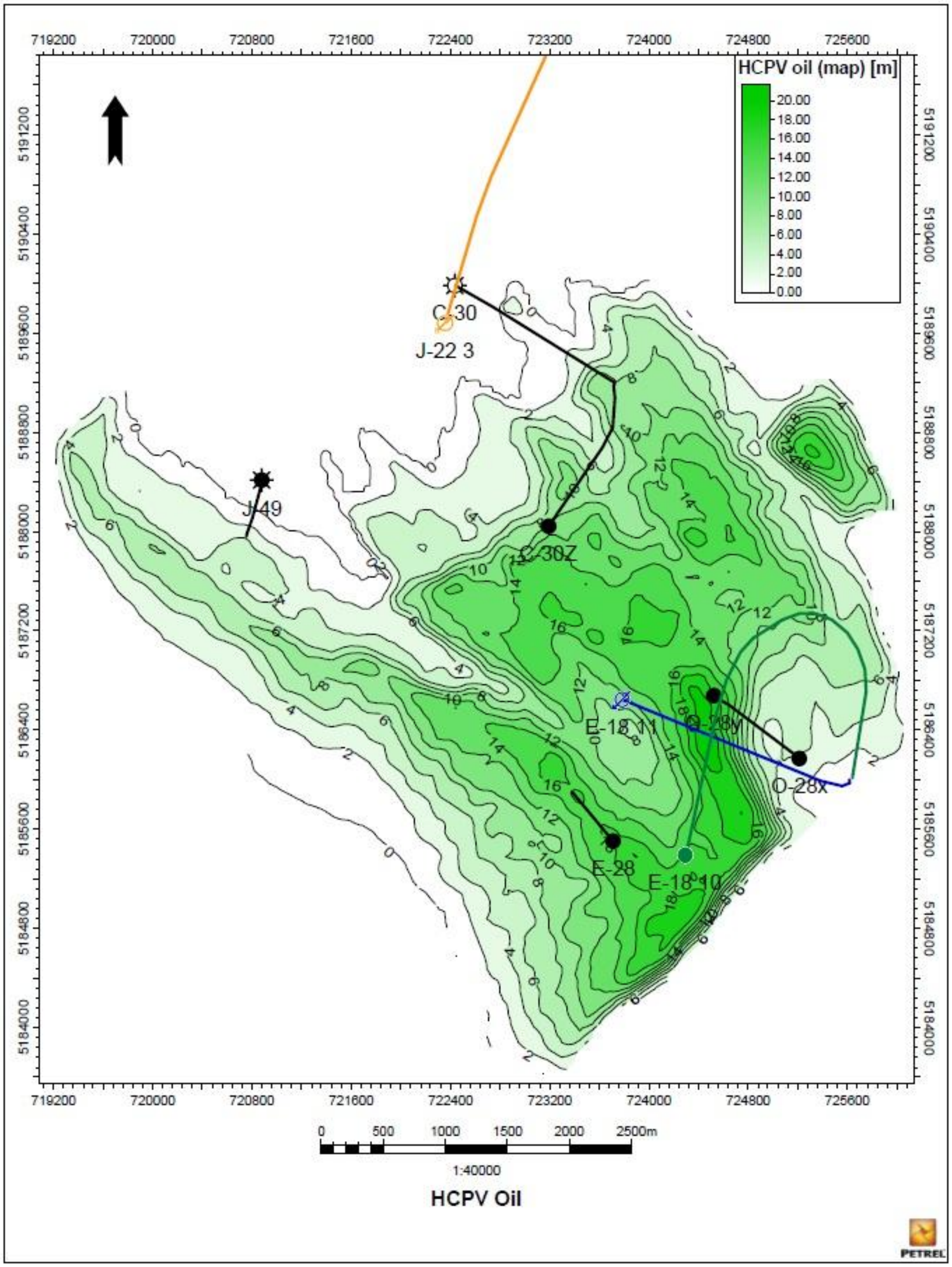

Figure B.6: Hydrocarbon pore volume of oil for the West Pool.

Table B.2: NTG cut offs applied to the base-case volumetric assessment of the West Pool.

NTG Cut Offs		Vsh	ϕ	Sw
GAS Zone	Upper BNA	<0.3	>0.11	<0.5
	Lower BNA	<0.3	>0.08	<0.5
OIL Zone	Upper BNA	<0.3	>0.12	<0.5
	Lower BNA	<0.3	>0.09	<0.5
WATER Zone		<0.3	>0.09	

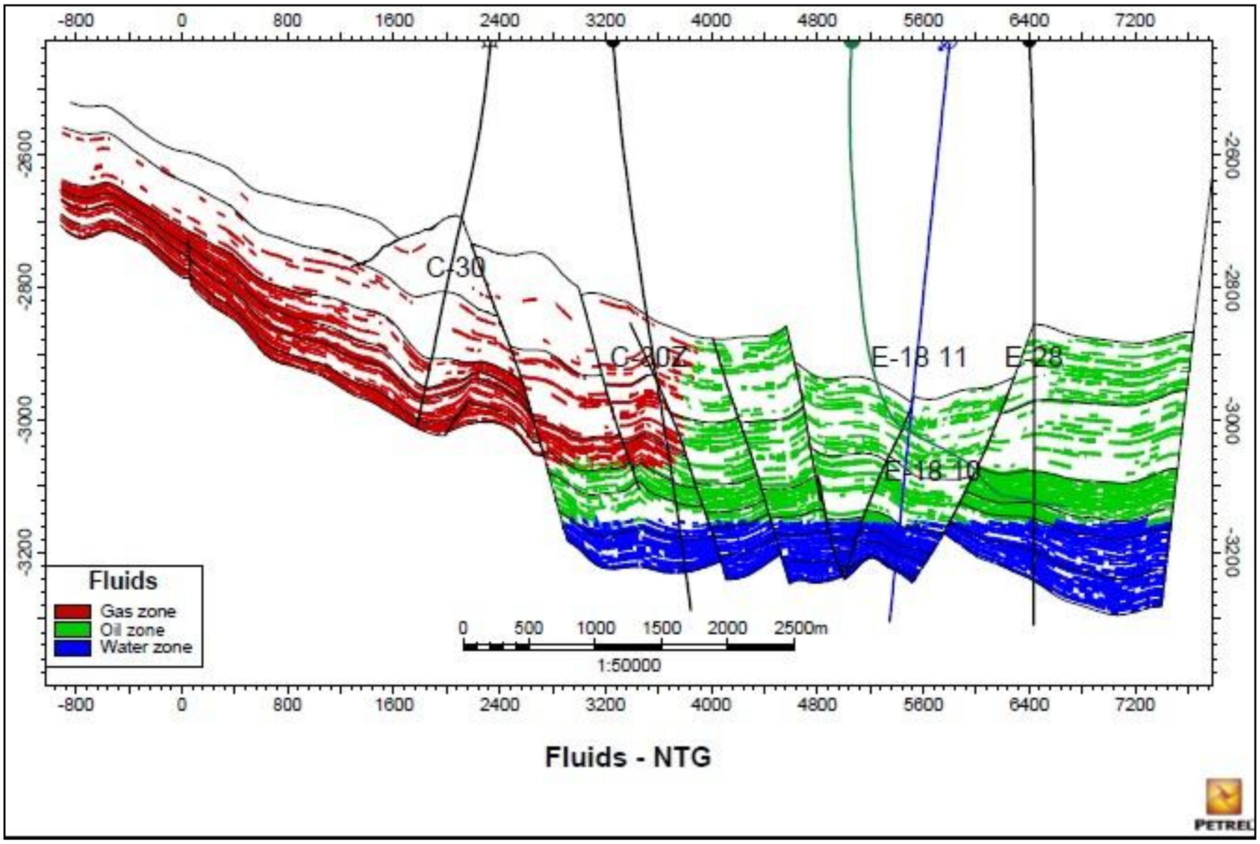

Figure B.7: NTG filter applied to the fluid property (Figure B.5).

Table B.3: Volumetric base-case assessment with NTG applied.

NTG Base Case	OOIP (x10^6 m^3)	GIIP(Free) (x10^9 m^3)	GIIP(Solution) (x10^9 m^3)
CNLOPB	75	13.2	9.6

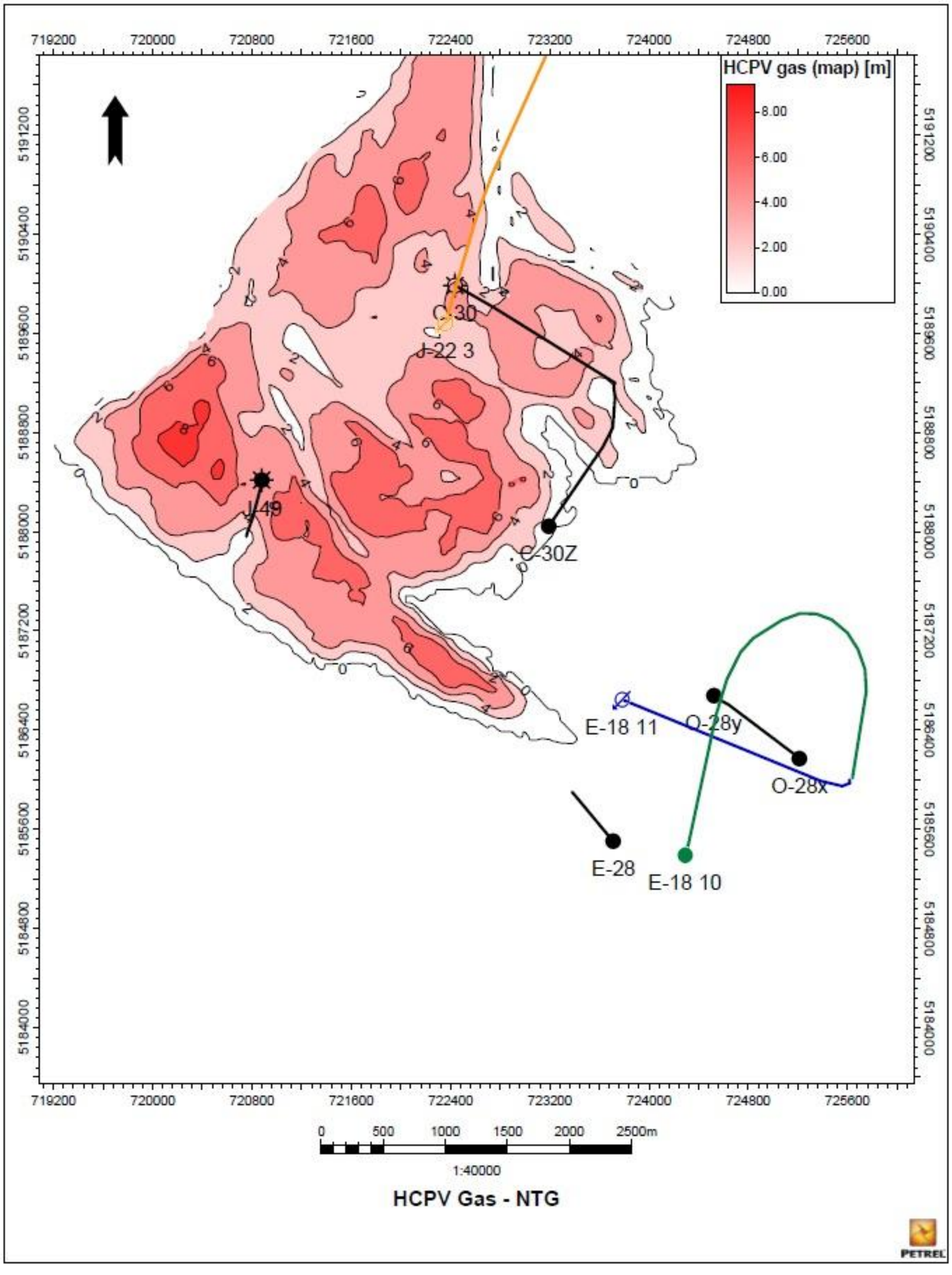

Figure B.8: Hydrocarbon pore volume (gas) of West Pool base-case assessment with NTG applied.

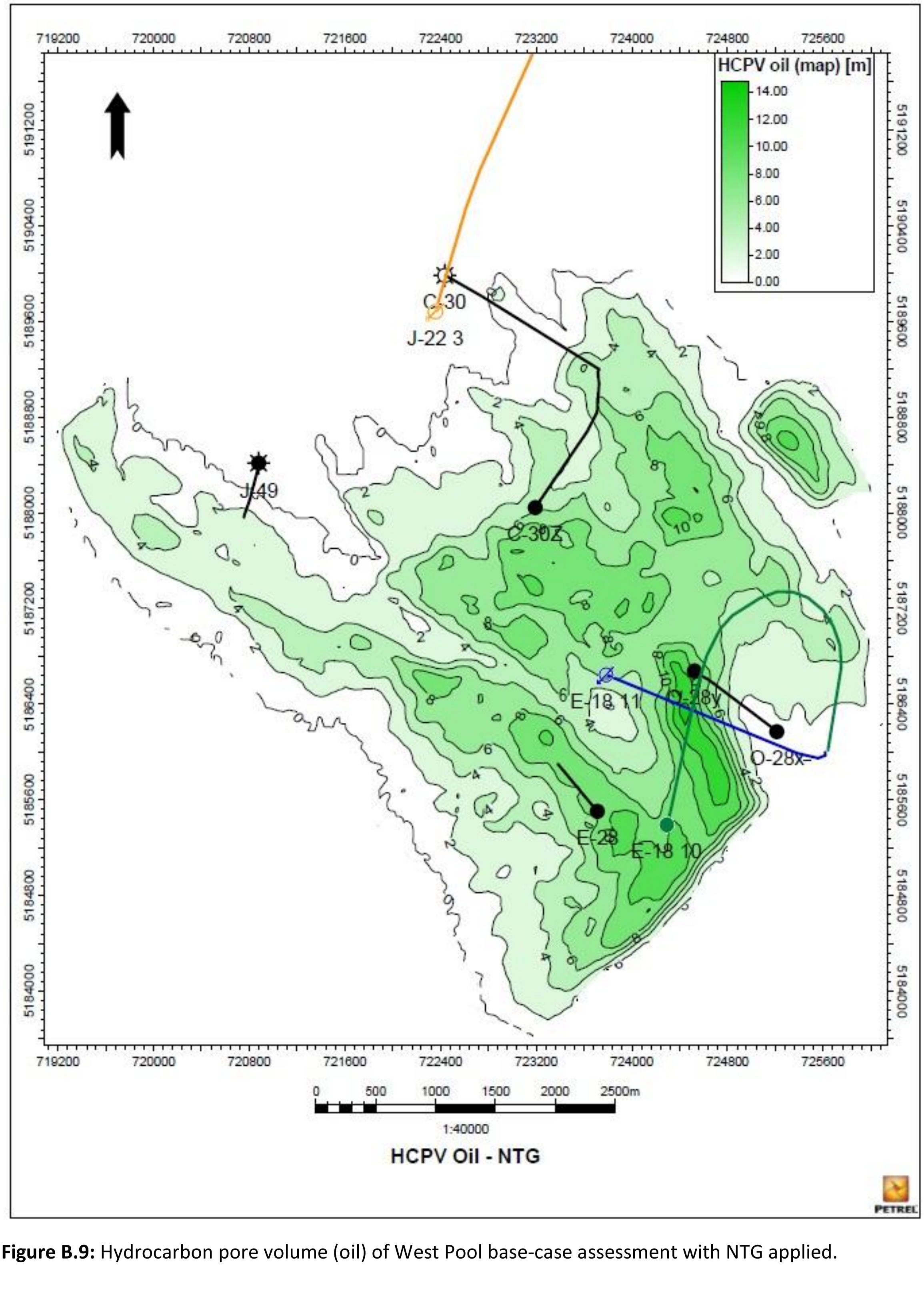

Figure B.9: Hydrocarbon pore volume (oil) of West Pool base-case assessment with NTG applied.

APPENDIX C: GEOLOGICAL MODELLING OF NORTH POOL AND BLOCKS 2 AND 5

Geological Modelling of North Pool and Blocks 2 and 5

In reviewing the DPA for the White Rose Extension Project, Board staff constructed a detailed 3D geological model for the North Pool, as well as Block 2 and Block 5 of the South Pool, to estimate in-place hydrocarbon resources and to create a static model for reservoir simulation. This model incorporated the available geophysical, petrophysical, geological and reservoir engineering data.

The structural framework for the model is based on the fault and surface interpretation supplied by the Proponent circa 2009. The model is confined vertically by the top Ben Nevis Avalon (BNA) formation and the Mid-Aptian Unconformity at the base, and is subdivided by stratigraphic surfaces interpreted from well log and core data. Stratigraphic zones were further subdivided by proportional layering. The model for the North Pool and Blocks 2 and 5 consists of a total of 4,532,880 cells with an average grid cell size of 53m x 51m x 1.5m.

The depositional environment (Figure C.1) and lithofacies (Figure C.2) within the North Pool and Blocks 2 and 5 were interpreted from core data and available literature on the BNA Formation within the White Rose area. A total of 7 wells, consisting of 2 development wells and 5 delineation wells, have been drilled to date in this area. At each well location, lithofacies and associated depositional environment interpretations were correlated with the log data within the cored intervals and predicted through the reservoir sections along the well trajectory based on the log response at the uncored sections. Depositional environment interpretations were upscaled to the 3D grid and the model was populated using a truncated Gaussian with trends algorithm. The lithofacies model was populated by six rock types by zone using sequential indicator simulation, and conditioned to the depositional environment model.

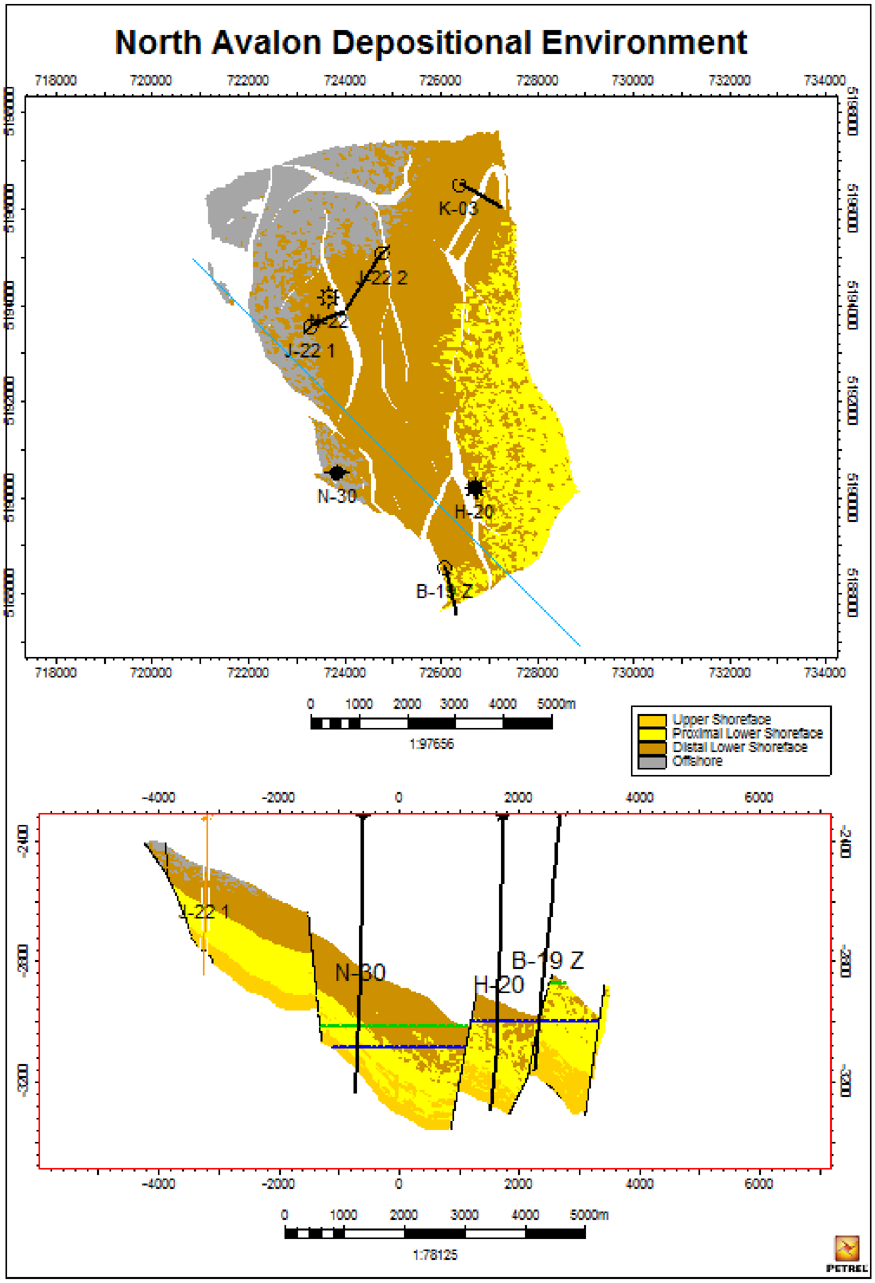

Figure C.1: Depositional environment model – North Pool region.

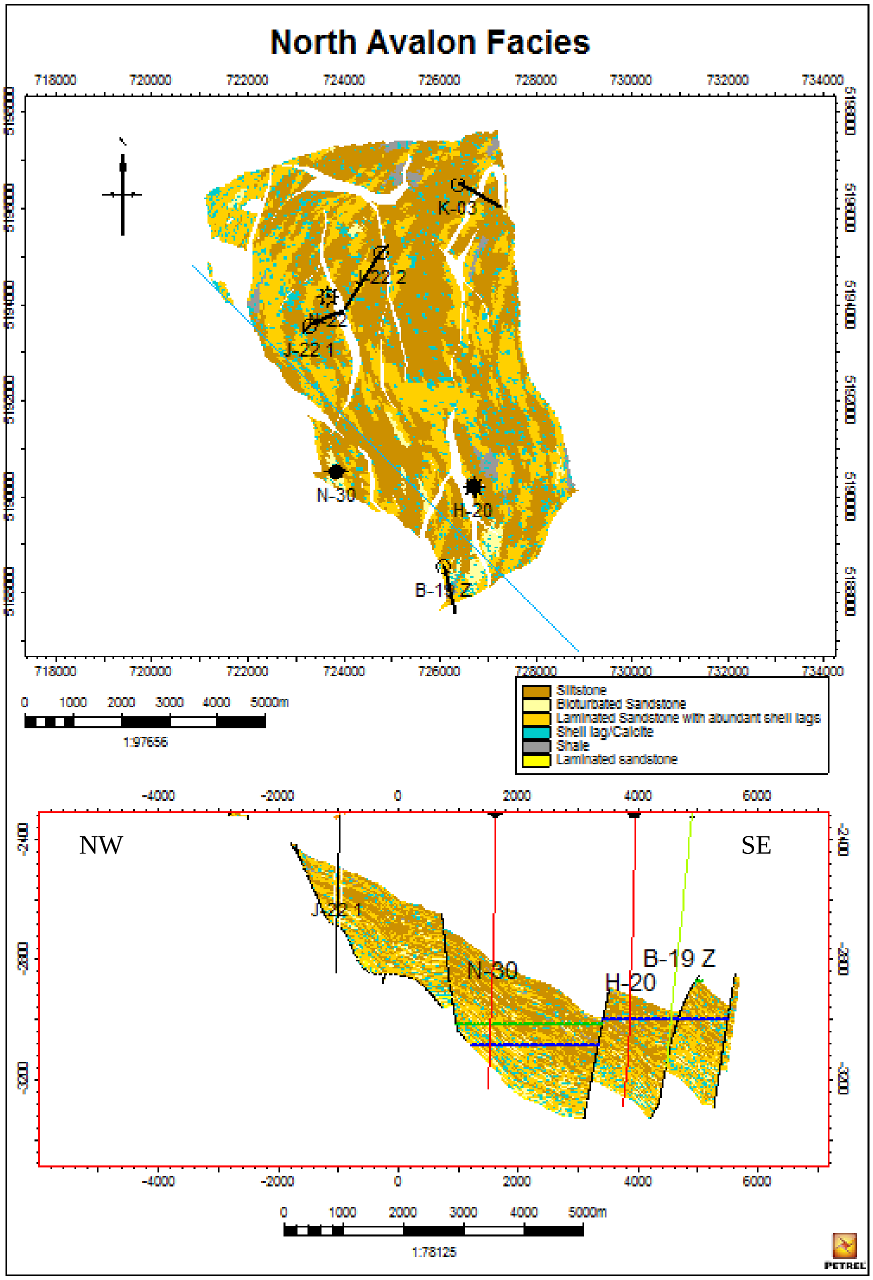

Figure C.2: North Pool region facies model.

The North Pool, as well as Blocks 2 and 5, were modeled using a hierarchical approach which allowed for the statistical populations of petrophysical data to be conditioned to the depositional environment and facies interpretations. The process of property modelling included upscaling porosity, water saturation and permeability into the 3D grid. Data analysis was utilized to analyze the statistical distribution of the data by zone and facies. Upscaled porosity data were conditioned to the lithofacies model and populated through the grid using sequential Gaussian simulation.

Water saturation data from well logs were upscaled to the grid and distributed using data analysis and a sequential Gaussian simulation algorithm co-kriged to the porosity model (Figure C.3). Permeability was modeled using upscaled well log data conditioned to facies and distributed across the grid area using data analysis and a sequential Gaussian simulation algorithm co-kriged to the porosity model.

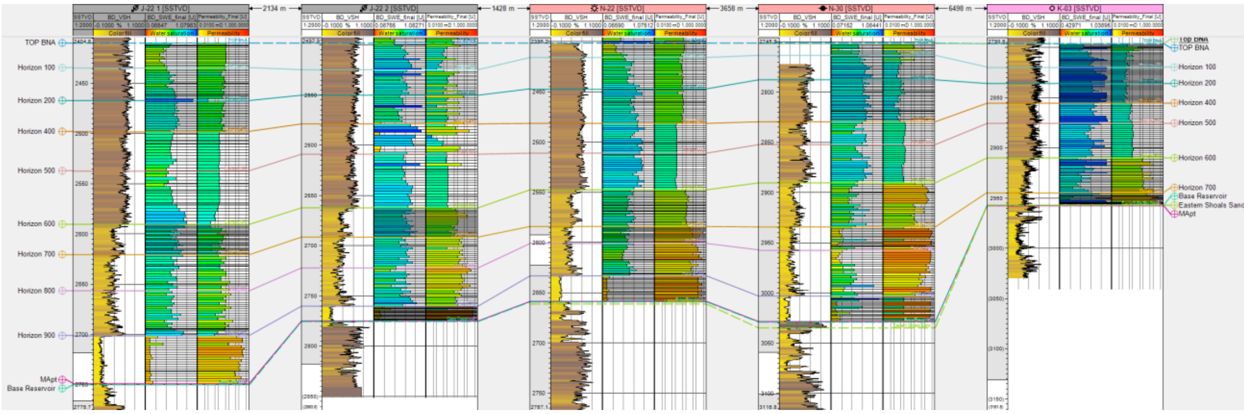

Figure C.3: Petrophysical properties for North Pool region wells.

The facies model of the North Pool region consisted of six rock types. Each facies was distributed by zone using a sequential indicator simulation algorithm. Depositional trends of the facies were modeled by zone using a truncated Gaussian with trends algorithm.

Board staff used the resulting deterministic hierarchical geological model as a basis for the stochastic assessment of the in-place hydrocarbon resources in the North Pool, Block 2 and Block 5 regions (Figures C.4 and C.5). Multiple parameters were varied during the evaluation, including porosity, water saturation, and hydrocarbon contacts (Figure C.6).

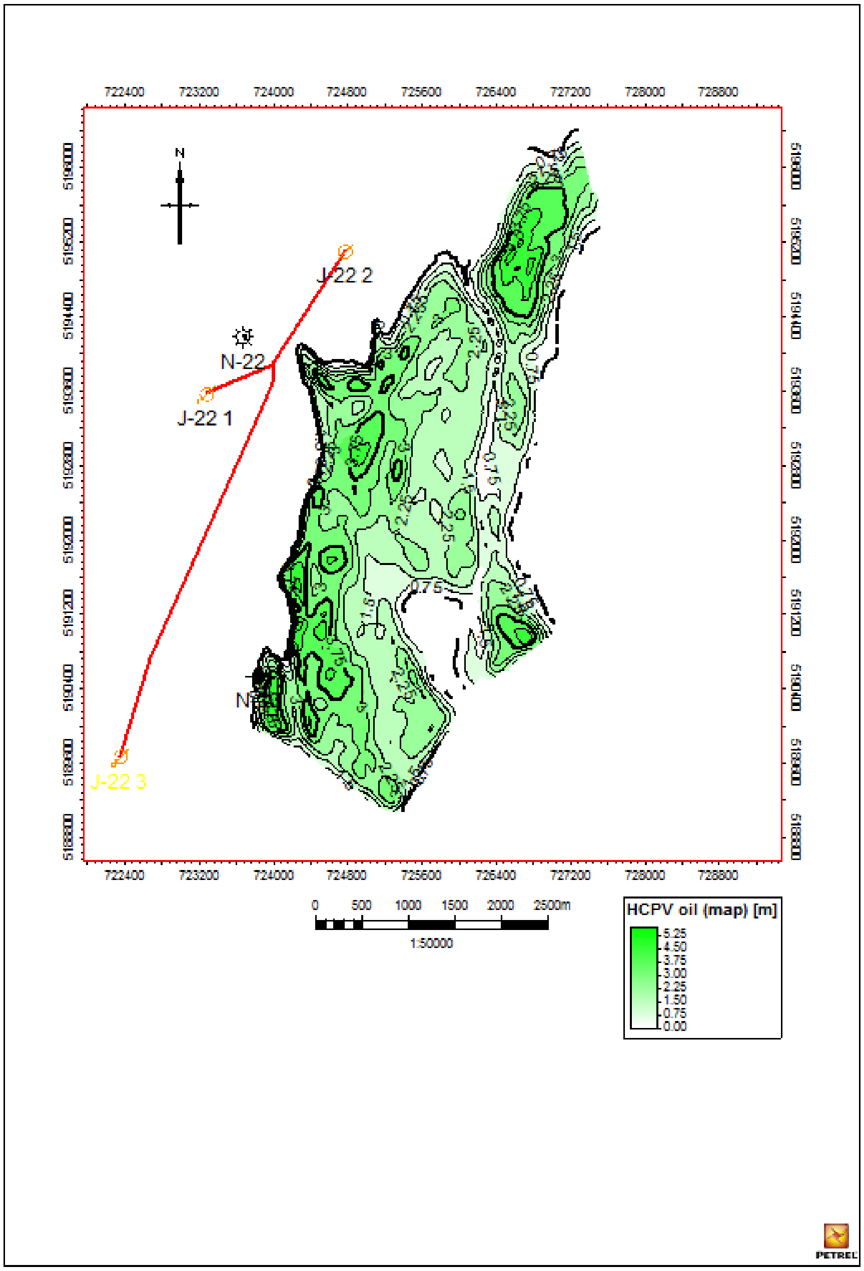

Figure C.4: Hydrocarbon pore volume oil map, North Pool.

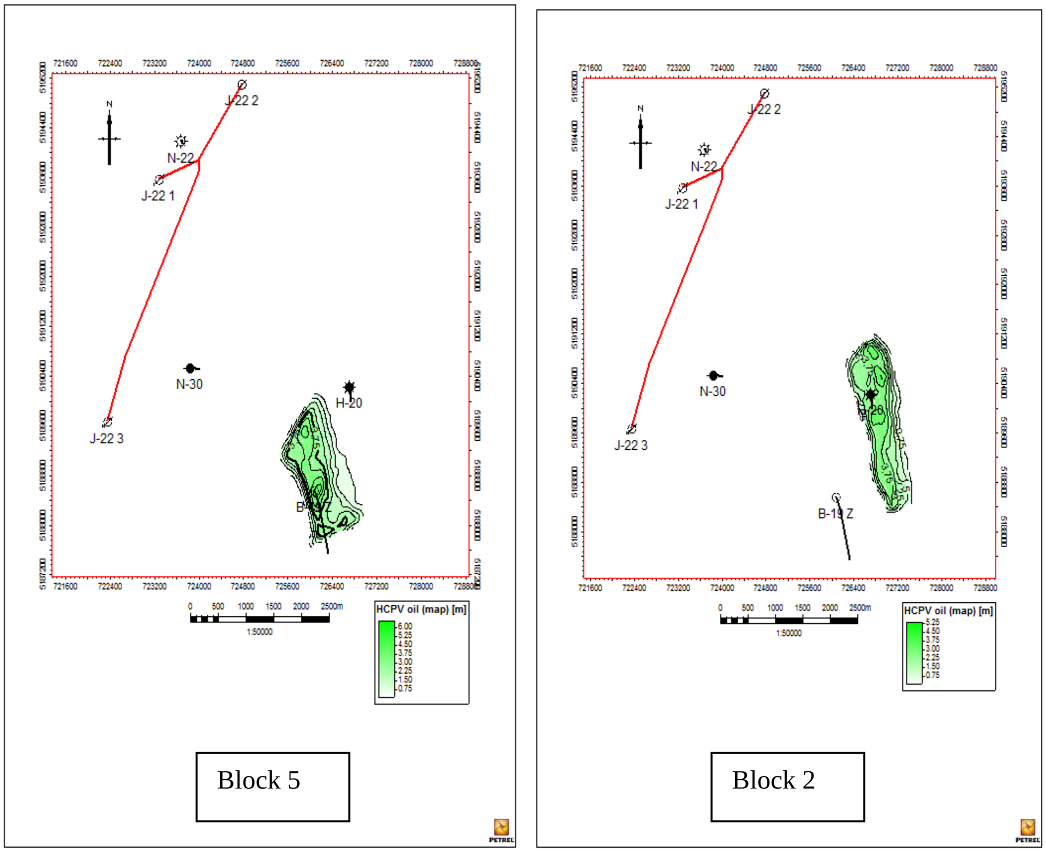

Figure C.5: Hydrocarbon pore volume oil map, Blocks 2 and 5.

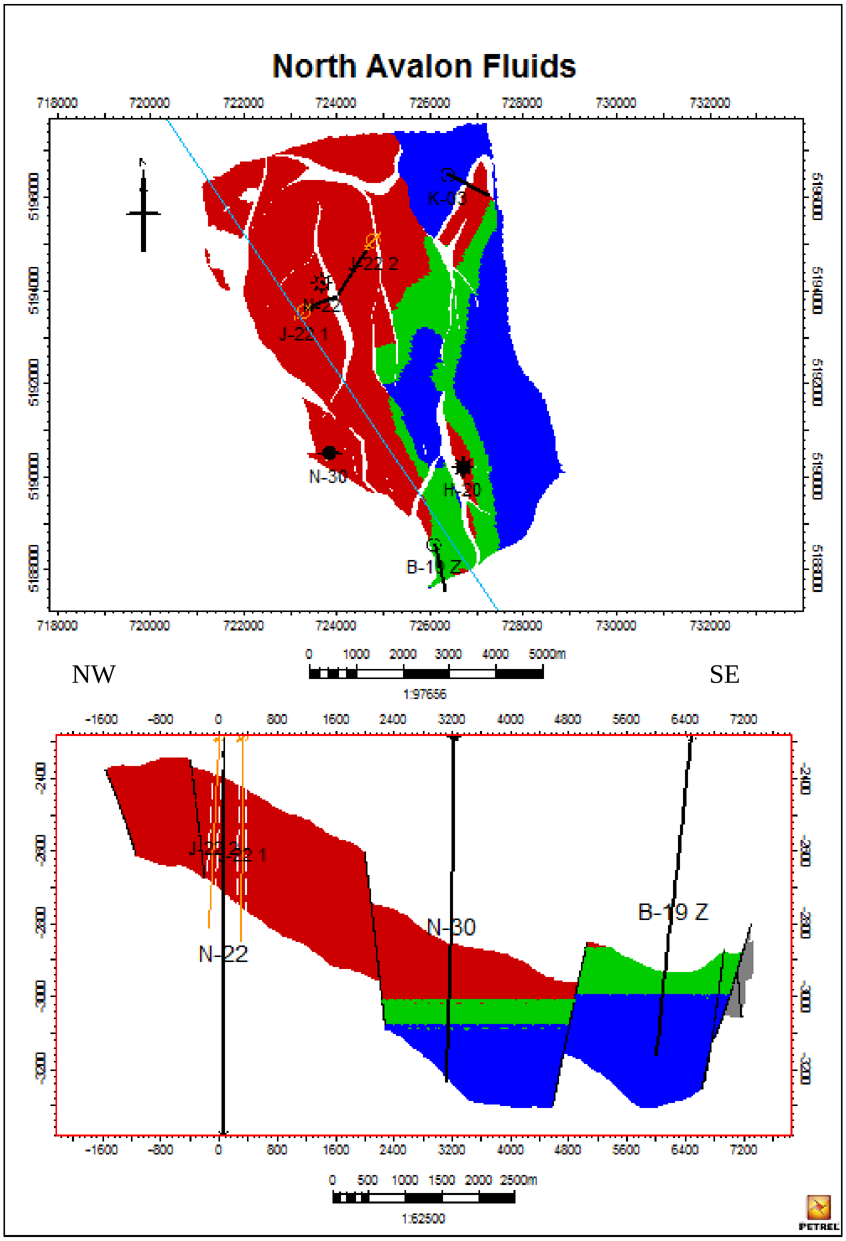

Figure C.6: North Pool fluid contacts.

A comparison of the Proponent's and Board staff's probabilistic in-place resource estimates (P90 downside case, P50 most likely case and P10 upside case) for the North Pool, Block 2 and Block 5 is shown in Table C.1.

Table C1: Staff's oil-in-place estimates for North Pool and Blocks 2 and 5 of South Pool.

Pool	Units	P90		P50		P10	
		Husky	C-NLOPB	Husky	C-NLOPB	Husky	C-NLOPB
North	MMbbls	30.2	84.9	39.0	103	50.3	125.2
	MMm^3	4.8	13.5	6.2	16.4	8.0	19.9
Blocks 2&5	MMbbls	27.7	41.5	45.4	49.6	47.2	56.6
	MMm^3	4.4	6.6	7.22	7.9	7.5	9.0

Overall, there are differences between the Proponent's and Board staff's volumetric assessment. Differences are attributed to variations in geological and reservoir modelling approaches, petrophysical analyses, and parameters varied in the uncertainty analysis. It should be noted that the Proponent's estimate of STOOIP in the North Pool has changed since the submission of the DPA for the West Pool pilot scheme (2009). Staff's volumetric assessment of the in-place hydrocarbons for the North Pool are more in agreement with the in-place volume (17.9 x MMm^3) quoted by the Proponent in the Condition 19 report submitted in 2009 as part of the West Pool pilot scheme. Staff analysis of Blocks 2 and 5 of the South Pool also demonstrate potential for greater hydrocarbon accumulation than that submitted by the Proponent, mainly due to different fluid contacts used in the volumetric assessment portion modelling process. Geological modelling and uncertainty analysis conducted by Board staff suggest the possibility of increased hydrocarbon resources north of the proposed well locations for the North Pool.

APPENDIX D: RESERVOIR SIMULATION MODELLING

Reservoir Simulation Modelling

D.1 West Pool Simulation Modelling

As discussed in Section 4.5.1.7, for analysis of the Application, Board staff created a reservoir simulation model for the West Pool using the Petrel Reservoir Engineering core. This model was built using a static geological model developed by staff in Petrel. The geological model was based on staff's independent assessment of available West Pool geological and petrophysical data. Based on this analysis, an OWC of 3155 m TVDss was used in the geological model, which is 15 m higher than the Proponent's OWC of 3170 m TVDss. Staff's interpretation of the GOC in the J-49 area was the same as the Proponent's.

Staff's geological model was based on an older vintage structural interpretation than was used for the Proponent's model. Details on staff's geological modelling work can be found in Appendix B. The differences in the structural interpretation caused a number of challenges for simulation as the resulting grids were different and required use of different well locations and equilibrium regions than the Proponent.

The porosity, water saturation, permeability and facies properties used in the simulation model were all generated in the geological modelling process.

To minimize simulation run times, the 50 m x 50 m geological model was upscaled to 100 m x 100 m. The resulting West Pool simulation model contains 68 x 97 x 155 cells for a total of 1.02 million cells. An illustration of the upscaled grid can be seen in Figure D.1.

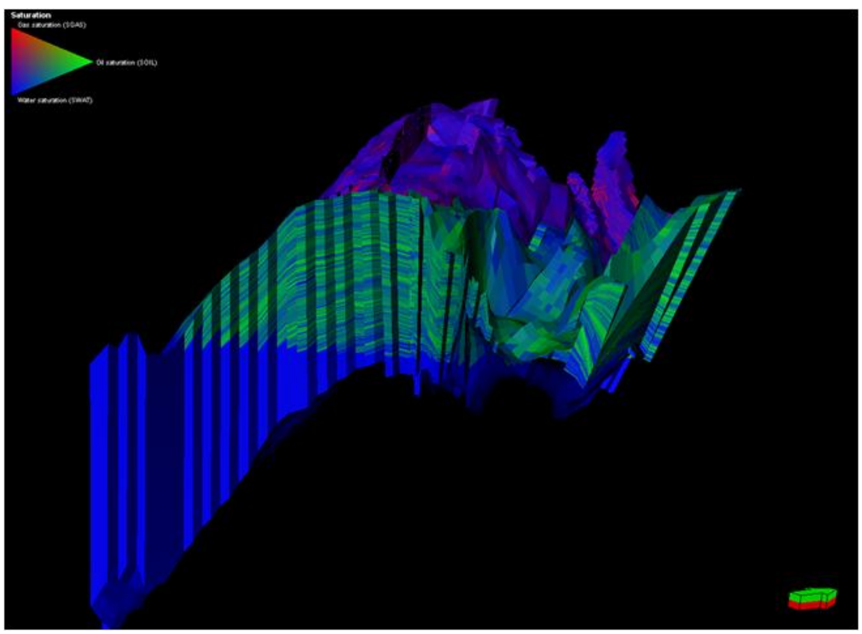

Figure D.1: C-NLOPB West Pool upscaled grid.

The Proponent's fluid data, relative permeability functions and rock compaction function were used in staff's base-case simulation model. Staff did evaluate a number of cases where relative permeability functions were adjusted, but the Proponent's functions as presented in the Application were used for staff's base case.

The Proponent's base-case model was set up with three equilibrium regions. As the oil column in the O-28Y area (Region 1) has no overlying gas, the GOC was set to 1000 m TVDss (a depth above the top of the grid), which resulted in only oil on top of water in this region. Staff attempted to create equilibrium regions that were similar to the Proponent's, but an exact match was not possible due to the differences in the structure/grid. Staff's OWC interpretation of 3155 m TVDss was used for each equilibrium region in the model. This differed from the Proponent's regions which used an OWC of 3170 m TVDss. An illustration of the equilibrium regions used in staff's model can be seen in Figure D.2.

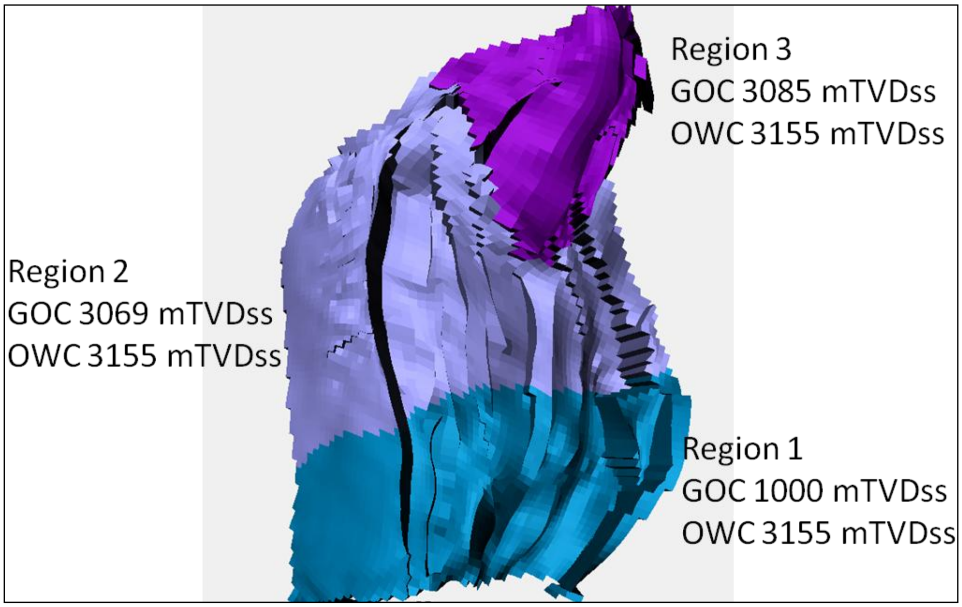

Figure D.2: C-NLOPB West Pool equilibrium regions.

Prior to performing predictive cases, the Proponent used a development strategy to history match its model to observed production and injection data from September 5, 2011 to May 9, 2012. Additional information obtained from the pilot scheme, such as the sealing nature of the JB18a fault and the BNA325 and BNA Shell Cement parasequences, were also incorporated into the Proponent's model. As a result of the history matching, the Proponent made modifications to the model permeability and relative permeability endpoints to achieve the best possible match. Staff's model utilized the Proponent's history match development strategy and various cases were examined where staff's model used similar modifications as the Proponent. Staff's model achieved a good match on bottom-hole pressure while producing the historical oil rate, but was unable to achieve a close match on total liquid rate. The issues with matching the liquid rate were caused by water saturation from staff's geological modelling being higher than the Proponent's water saturation. Time constraints precluded further adjustment of the model and investigation.

The Proponent's model had two development strategies for after the history match time period. The first strategy was for the prediction of the pilot scheme well pair from the end of the history match phase until January 1, 2017 when the first WHP wells were predicted to come online. The other development strategy was for the prediction of the pilot scheme wells and the 26 wells to come online from the WHP from January 1, 2017 out to January 1, 2030. Details on the constraints and assumptions used for these development strategies can be seen below.

Production Wells

- Maximum liquid production rate – 2500 m3/d
- Maximum reservoir production rate – 5000 rm3/d
- Maximum watercut – 97%
- Maximum GOR – 2000 m3/m3
- Minimum BHP – 150 barsa

Injection wells

- Maximum water injection rate –5000 m3/d
- Maximum BHP – 600 barsa
- VRR varied between 1.0 and 1.1

Schedule

- First well drilled, completed and tied in 1/1/2017
- 26 wells drilled over a 5 year period
- Actual Drill schedule implemented in IPM

Staff used the Proponent's development strategies and well and group rate production, pressure, injection and voidage constraints but some adjustments to the well locations were necessary. In general, the same well locations were used in staff's model; however, due to differences in structural interpretation, equilibrium regions, interpreted fluid contacts and property modelling, some adjustments to well depths, trajectories and completions had to be made in order to produce adequate oil volumes and/or reduce water and gas production for some wells. These adjustments were made while attempting to honour the Proponent's intended flow unit targets for the respective wells as much as possible. Multiple simulation cases were run in an attempt to maximize oil recovery for the pool. One well pair, the PRD11B and INJ11A wells, did have to be significantly modified and moved due to the Proponent's well locations not intersecting the grid in staff's model, because of differences in the structure in the area.

The resulting recoverable oil from staff's base-case simulation model is 17.3 MMm^3 (108.8 MMbbls), which is similar to the 16.65 MMm^3 (104.7 MMbbls) recoverable predicted by the Proponent's model. However, the recovery factor achieved by staff's model only equates to 14.4 percent compared to the 24 percent recovery factor estimated from the Proponent's model. This difference is due to the estimated 119.7 MMm^3 (753 MMbbls) STOOIP in staff's simulation model being considerably larger than the 69.0 MMm^3 (434 MMbbls) STOOIP estimated in the Proponent's model. A higher recoverable oil could most likely have been achieved from staff's model due to the much larger oil-in-place, but due to time constraints, and the intention of honouring the proposed well locations and proposed depletion scheme as much as possible, no further work on this was completed.

A comparison of the simulated oil production rate and cumulative volume from staff's model compared to the Proponent's can be seen in Figure D.3.

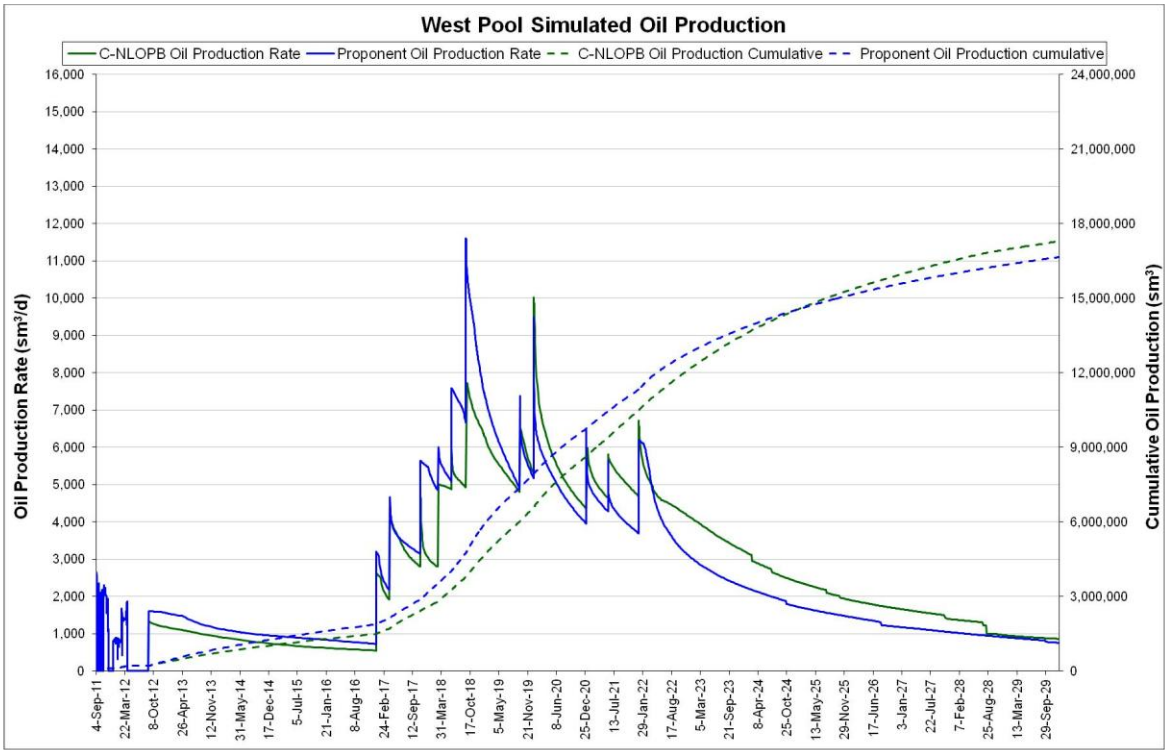

Figure D.3: C-NLOPB vs. Proponent base-case oil production for the West Pool.

Due to the differences in structure and properties, some wells in staff's model produced less oil than the Proponent's, while others produced more. The cumulative oil production from the models is comparable.

A comparison of the simulated water production rate and cumulative volume from staff's model compared to the Proponent's can be seen in Figure D.4.

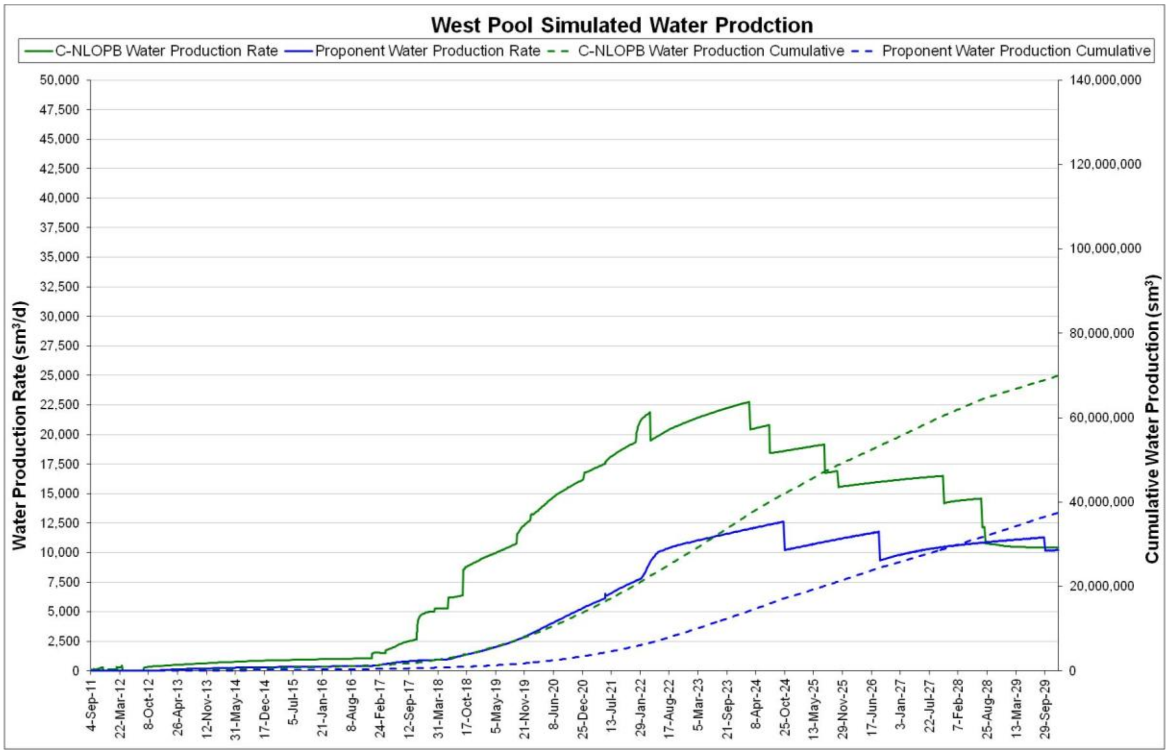

Figure D.4: C-NLOPB vs. Proponent base-case water production for the West Pool.

The water production from staff's model is substantially higher than the Proponent's. This is due to the water saturation distribution in staff's model being higher than the Proponent's. As a result, many of the producers in staff's model begin producing water earlier than corresponding wells in the Proponent's model. This was the case with the E-18 10 pilot producer, which caused issues when trying to achieve a good history match. Another possible cause of the higher water production in staff's model is the 3155 m TVDss OWC used in staff's model, which is 15 m higher than the OWC of 3170 m TVDss used in the Proponent's model.

A comparison of the simulated gas production rate and cumulative from staff's model compared to the Proponent's can be seen in Figure D.5.

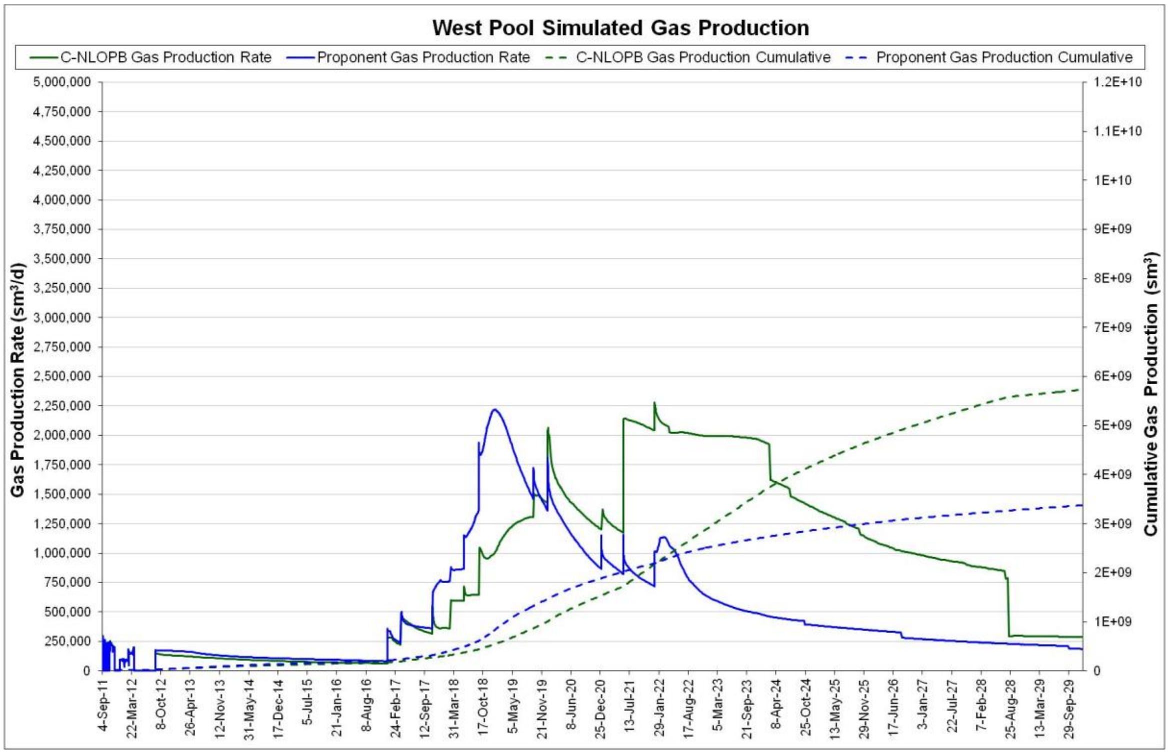

Figure D.5: C-NLOPB vs. Proponent base-case gas production for West Pool.

As shown in Figure D.5, staff's model and the Proponent's model reach similar peak gas production rates, with the Proponent's peak arriving earlier, while staff's arrives later but is more prolonged. As a result of the prolonged period, staff's cumulative gas production is higher than the Proponent's. These differences in gas production are primarily due to the different structural interpretation used for staff's model and the equilibrium regions that were created as a result. Due to the equilibrium region set up, the West Pool gas cap extends farther laterally in staff's model than in the Proponent's. This causes gas breakthrough from the gas cap in the northernmost producers in staff's model, so these wells have higher and more sustained gas production rates than the same wells in the Proponent's model. Staff could have made adjustments to the equilibrium regions to address these issues but time constraints did not allow this. Slight adjustments were made to the well trajectories and completions, but in the interest of honouring the proposed depletion scheme, no major adjustments to well location were made for these producers.

A comparison of the simulated reservoir pressure from staff's model compared to the Proponent's can be seen in Figure D.6.

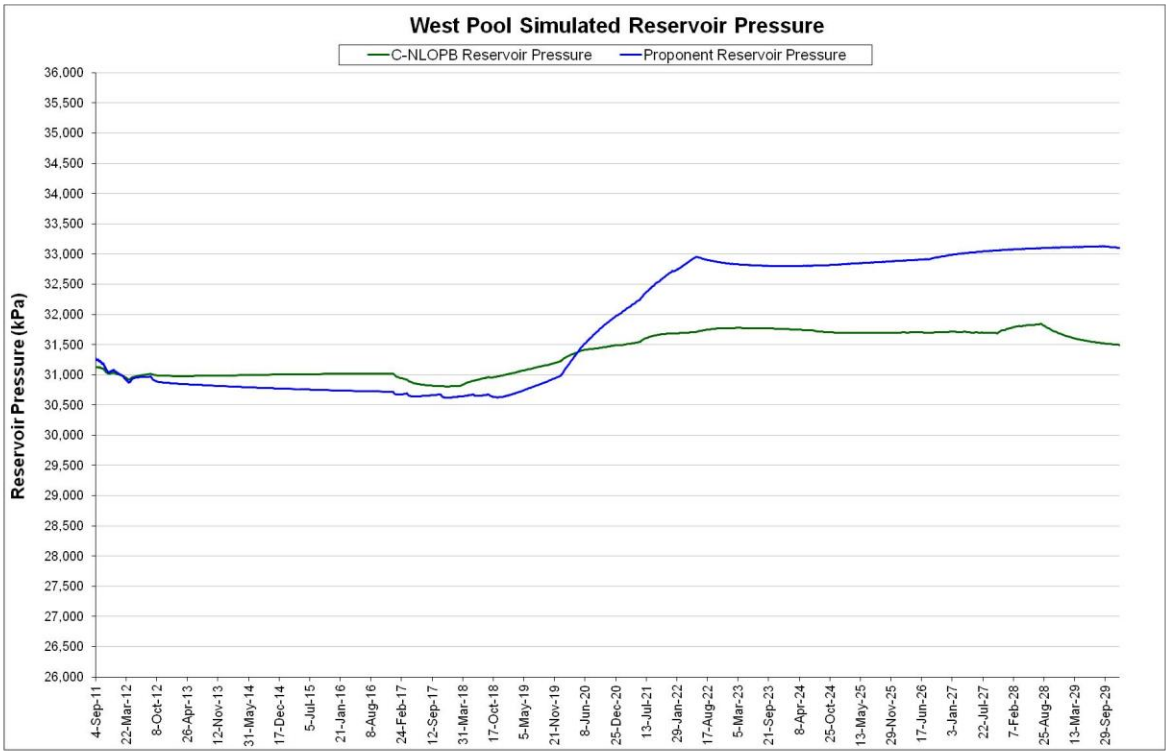

Figure D.6: C-NLOPB vs. Proponent base-case reservoir pressure for West Pool.

The simulated reservoir pressure in staff's model is very comparable to the Proponent's until mid year 2018. At this point the reservoir pressure in both models begins to increase before leveling off, but the increase is higher in the Proponent's model.

Based on staff's West Pool reservoir simulation model and review of the Proponent's reservoir simulation model, the following conclusions can be made:

- The Proponent's West Pool reservoir simulation model is a reasonable representation of the reservoir, given the known geological, petrophysical and reservoir engineering data.
- The Proponent has provided sufficient reservoir engineering data for the West Pool to address the requirements set forth in the Development Plan Guidelines.
- The proposed WHP and existing *SeaRose FPSO* topside facilities are adequate to handle the anticipated production from the West Pool.

D.2 North Pool Simulation Modelling

For analysis of the Application, staff developed an independent North Pool simulation model using the Petrel Reservoir Engineering core. The model was built using a geological model developed by geoscience staff in Petrel. The geological model was based on independent assessment of the available geological and petrophysical data for the North Pool. The geological model was developed using an older vintage structural interpretation than that used for the Proponent's model. Details on staff's geological modelling work can be found in Appendix C.

Staff's 50 m x 50 m geological model covered the entire North Pool and contained 136 x 202 x 165 cells, resulting in a total of 4.5 million cells. Instead of upscaling the grid to 100 m x 100 m, the grid was cut down to include only the oil-bearing fault blocks in the N-30 delineation well area, as was done by the Proponent. This resulted in staff's simulation grid containing 45 x 66 x 165 cells for a total of 0.49 million cells. An illustration of the grid from staff's model can be seen in Figure D.7.

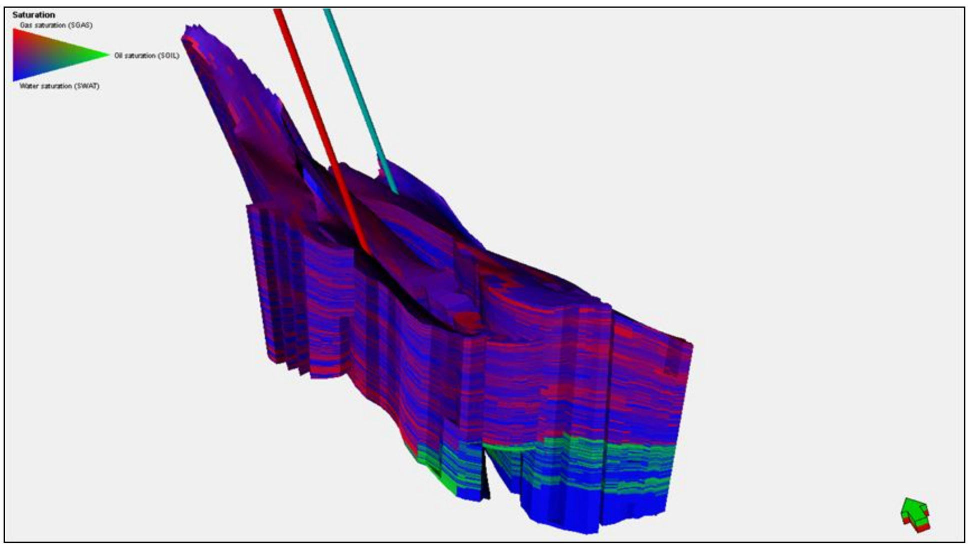

Figure D.7: C-NLOPB North Pool grid.

The porosity, water saturation, permeability and facies properties used in staff's North Pool simulation model were all generated in the geological modelling process.

For the predictive cases in ECLIPSE, the Proponent's fluid model, relative permeability functions and rock compaction functions were used in staff's simulation model. Staff evaluated a number of cases where relative permeability functions were adjusted, but the Proponent's functions as presented in the Application were used for staff's base case.

For the base case, staff also used a similar development strategy to the Proponent with the same well and group rate production, pressure and injection constraints. Details on the constraints used for the development strategy can be seen below.

Production Constraints

- Max. Oil Rate – 1500 m3/d
- Max. Liquid Rate – 3000 m3/d
- Max. Res. Rate 6000 m3/d
- ALQ – 250000 m3/d
- Min. BHP - 200 Bar
- Min THP – 50 Bar

Injection Constraints

- Max Surf Rate – 5000 m3/d
- Max BHP – 580 Bar
- VRR – 1.0

The difference in the development strategy used in staff's model was the location of the production well. It was not possible for staff to use the same location for the producer as the Proponent, due to considerable difference in the structural interpretation. As a result, staff's base-case simulation used two producers in an attempt to access similar oil pay to the Proponent's production well. Both of the producers used were located in the general area of the Proponent's well, but they were placed at different depths in the oil column. Staff's producers were also perforated at different intervals than the Proponent's due to the differences in property distribution between the two models. Staff performed multiple simulation runs to determine the best location for the producers. Cases to evaluate the location of the water injector were not run due to time constraints.

Staff's model used the same location for the proposed water injector as the Proponent's model. This caused issues with pressure support for staff's model, as the water injector location was not optimized for the structure or properties in staff's grid. Staff was unable to optimize the water injector location for the grid due to time constraints.

The resulting recoverable oil from staff's base-case simulation model is 0.71 MMm^3 (4.5 MMbbls), which is slightly lower than the 0.88 MMm^3 (5.6 MMbbls) recoverable predicted by the Proponent's model. However, the recovery factor achieved by staff's model equates to only 8 percent compared to 14 percent estimated from the Proponent's model. This difference is due to the estimated 8.8 MMm^3 (55.4 MMbbls) STOOIP in staff's model being larger than the 6.4 MMm^3 (40.3 MMbbls) STOOIP estimated in the Proponent's model.

A comparison of the simulated oil production rate and cumulative from staff's model compared to the Proponent's can be seen in Figure D.8.

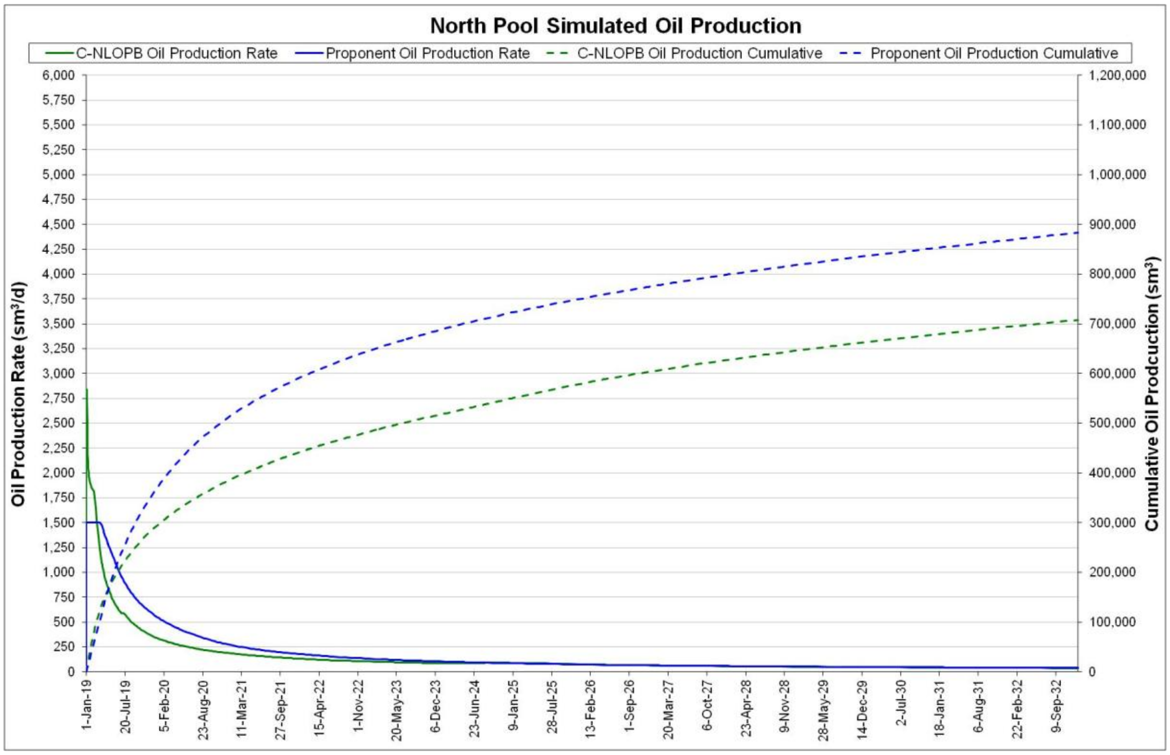

Figure D.8: C-NLOPB vs. Proponent base-case oil production for North Pool.

The initial production rate from staff's model is higher than the Proponent's due to the extra producer. Production from this extra well quickly drops off however, as it is located close to the GOC, so the GOR increases very rapidly and oil production decreases as a result. Initial production from staff's other producer is similar to the Proponent's but drops off more quickly. This well was placed closer to the OWC than the Proponent's, so it begins to produce water earlier, which leads to a decrease in oil rate. The oil rate drop is also influenced by the water injector in staff's model not being optimized for the grid and properties, which caused the pressure support to not be as effective as the Proponent's model.

A comparison of the simulated water production rate and cumulative from staff's model compared to the Proponent's can be seen in Figure D.9.

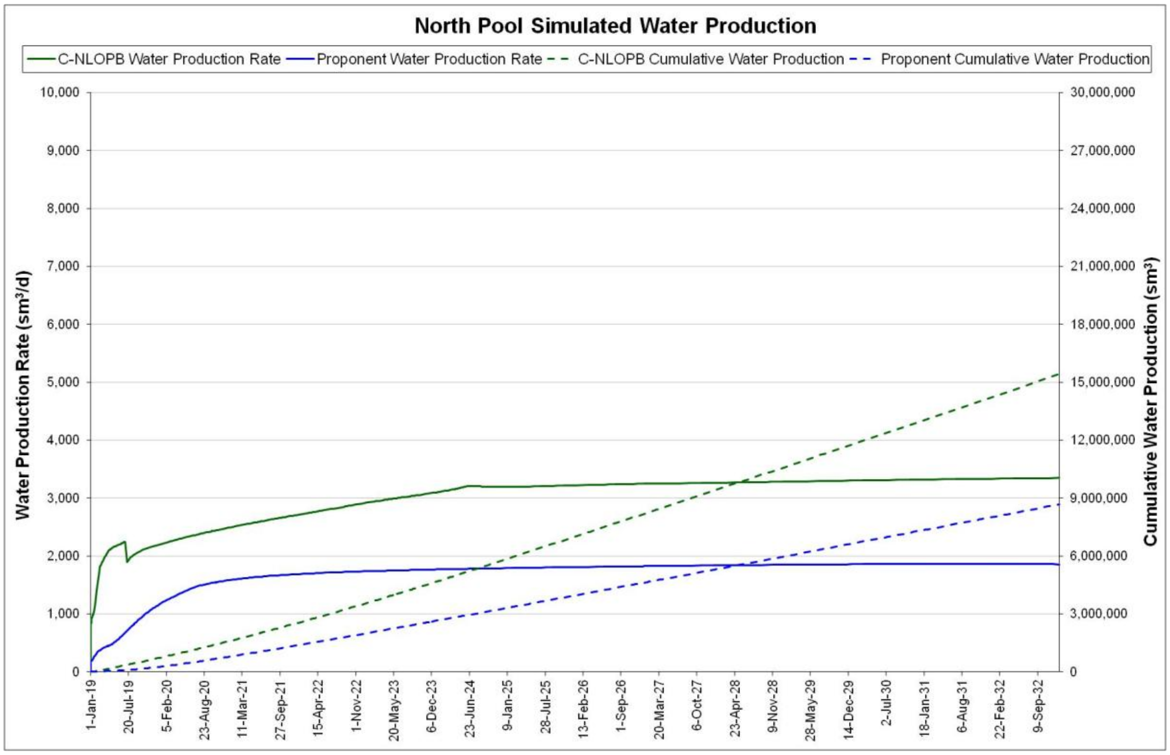

Figure D.9: C-NLOPB vs. Proponent base-case water production for North Pool.

As illustrated in Figure D.9, the water production rate from staff's model is higher than the Proponent's. This is mainly due to the water saturation distribution from staff's geological model being higher than the Proponent's water saturation. Also, as mentioned, the main producer in staff's model was placed closer to the OWC than the producer in the Proponent's model. Due to time constraints, staff was unable to investigate the higher water saturation distribution further or to make adjustments to the model to attempt to decrease the water production.

A comparison of the simulated gas production rate and cumulative from staff's model compared to the Proponent's can be seen in Figure D.10.

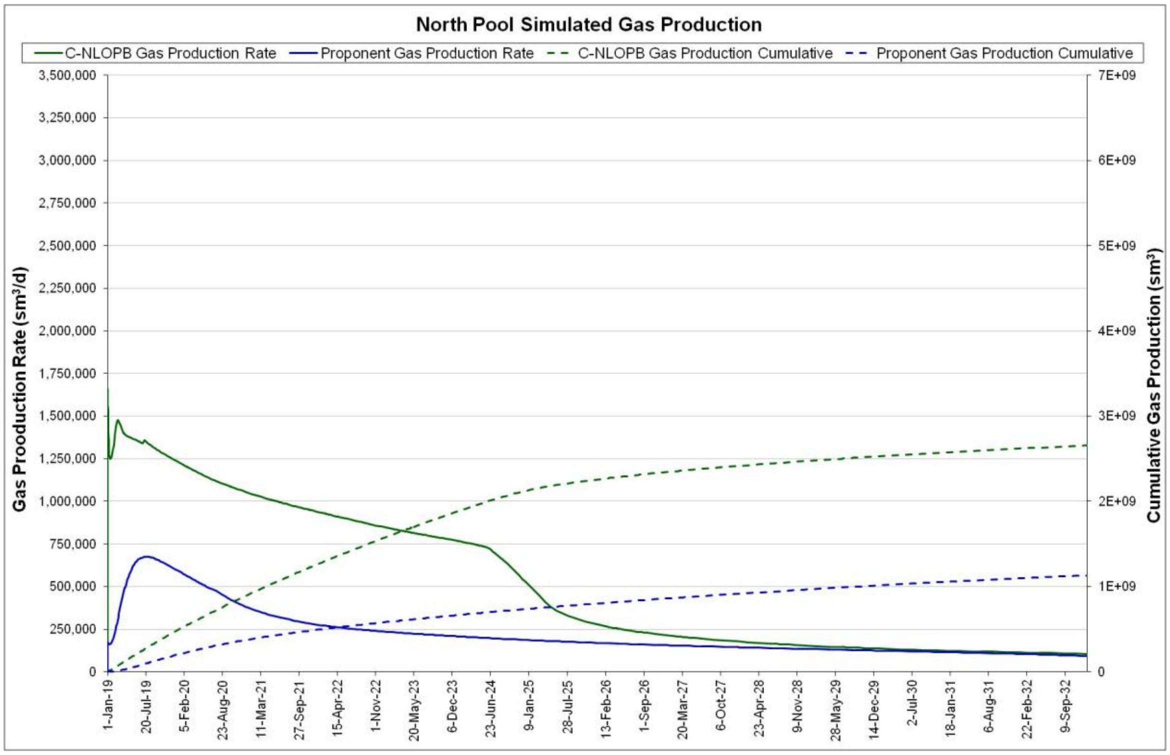

Figure D.10: C-NLOPB vs. Proponent base-case gas production for North Pool.

There is a large discrepancy between the gas produced in staff's model versus the Proponent's. Due to time constraints, staff was unable to investigate these differences or make adjustments to the model. One cause of the earlier and higher gas production was the use of the second producer in staff's model. This well was located in a fault block in staff's model that was juxtaposed higher against the neighbouring fault blocks than it was in the Proponent's model. As a result, the producer that staff used in this higher fault block was located immediately below the gas cap, and therefore it begins to produce high gas volumes after production commences.

A comparison of the simulated reservoir pressure from staff's model compared to the Proponent's can be seen in Figure D.11.

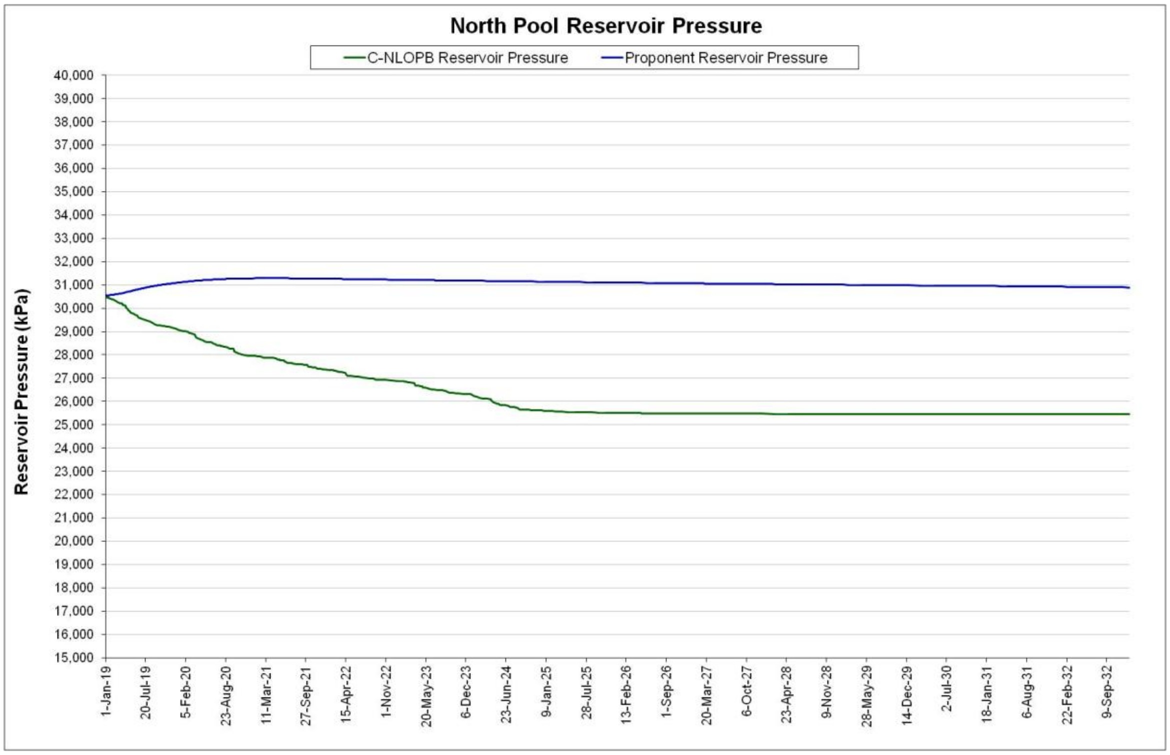

Figure D.11: C-NLOPB vs. Proponent base-case reservoir pressure for North Pool.

As shown in Figure D.11, the reservoir pressure in staff's model begins to decrease as soon as production begins, before levelling off in mid year 2024, while the reservoir pressure in the Proponent's model remains stable throughout the forecasted period. The drop in pressure in staff's model is most likely due to the water injector in staff's model not being optimized for the structure and properties in the model. This results in the water injector being unable to provide adequate pressure support for the producers in staff's model. As discussed, staff would have liked to attempt to optimize the location of the water injector in the model and further investigate the cause of the drop in reservoir pressure, but were unable to due to time constraints. The drop in reservoir pressure in staff's model may have also contributed to the higher gas production compared to the Proponent's.

Based on staff's North Pool reservoir simulation model and review of the Proponent's reservoir simulation model, the following conclusions can be made:

- The Proponent's North Pool reservoir simulation model is a reasonable representation of the reservoir given the known geological, petrophysical and reservoir engineering data.
- The Proponent has provided sufficient reservoir engineering data for the North Pool to address the requirements set forth in the Development Plan Guidelines.
- The proposed WHP and existing *SeaRose FPSO* topside facilities are adequate to handle the anticipated production from the North Pool.