Staff Analysis

of the

North Amethyst Development Plan

Amendment Application

Gas Flood in Support of Oil Production

ISBN # 978-1-927098-84-4

C-NLOPB

Table of Contents

List of Figures

List of Tables

1. Purpose

The purpose of this document is to provide the Board with an assessment of the application received from Husky Oil Operations Limited (Proponent) to amend the North Amethyst Development Plan. The Proponent plans to implement gas injection as an option to enhance oil recovery from the Ben Nevis – Avalon (BNA) Pool in the North Amethyst Field. This analysis considered resource management, operations, safety and environment aspects of the application.

The Staff Analysis does not consider any benefits or socio-economic aspects of the proposed project. These matters were assessed in a separate North Amethyst Benefits Plan prior to making a decision on the original Development Plan. The approach is consistent with section 45(2) of the *Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act*.

2. Executive Summary

On June 29, 2017, Husky Energy (Proponent) submitted to the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) on behalf of its co-ventures Suncor Energy and Nalcor Energy-Oil and Gas, a Development Plan Amendment Application related to Gas Flood in Support of Oil Production at North Amethyst.

The proposed gas flood is an amendment to the existing North Amethyst Development Plan (Decision Report 2008.03).

The documents describe the Proponent's intention to inject produced gas, instead of or in addition to water injection, as a means of improving sweep efficiency in the North Amethyst BNA Pool.

Husky indicated that the objectives of the development plan amendment is as follows:

- To supplement or replace water flood with gas flood to provide pressure maintenance and sweep; and,
- Gas flood offers the potential for improved oil recovery and production acceleration, without the need to over void with water and risk increasing water cut.

Upon receipt of the Development Plan Amendment Application, C-NLOPB technical staff (Staff) reviewed the documents for completeness. Based on their review, Staff requested additional information in a letter dated on December 4, 2017. In June 2018, the Proponent resubmitted a document titled *North Amethyst Development Plan Amendment Gas Flood in Support of Oil Production at North Amethyst (June 2018),* which is considered to be "the Application" and is the subject of this analysis.

Information provided by the Proponent in response to the letter were assessed by Staff and in October 2018 the documents were deemed sufficiently complete.

With respect to industrial benefits, Staff assessed the Application and determined an amendment to the existing North Amethyst Benefits Plan (Decision 2008.03) is not required.

At the September 28, 2018 Board meeting it was decided that a public review was not necessary for the Application.

Staff reviewed the Application from the perspective of resource management, operations, safety and environment. The following is a summary of this review.

Resource Management

In assessing the resource management aspects of the Application, Staff reviewed the Proponent's seismic interpretation, geological model and reservoir simulation model. Staff also conducted a review of geological, petrophysical and production data acquired since approval of the original North Amethyst Development Plan in 2008 (Decision 2008.03). Staff did not construct independent geological reservoir and simulation models due to other modelling priorities and the minor nature of the proposed change in the depletion scheme. In addition, because the BNA Pool is in the late stage of its producing life, Staff did not deem a full geological and simulation model build to be justified for review of the Application.

In the original North Amethyst Development Plan (Decision 2008.03), Staff identified that the proposed depletion strategy using only water flood could potentially result in a significant volume of attic oil trapped between the oil producers and the gas-oil contact (GOC). Currently, the Proponent is proposing to implement gas injection as an option to enhance oil recovery. Staff agrees that gas flooding has the potential to sweep attic oil to the existing producers and increase overall recovery of the BNA Pool.

In addition, Staff are in agreement with the Proponent's models. The models indicate that gas flooding is not expected to be a detriment to oil recovery. In each modelled scenario, the predicted oil recovery was increased or accelerated.

Based on Staff analysis and performance trends of the existing oil producers, Staff conducted an assessment of estimated ultimate recovery (EUR) for the BNA Pool. As a result, Staff now expects a proved and probable EUR of 9.14 MMm^3 (57.5 MMbbls). This estimate is a decrease from Staff's previous assessment of 10.8 MMm^3 (67.9 MMbbls) at the time of North Amethyst Development Plan approval.

Gas handling capacity on the *SeaRose FPSO* has been the main limiting factor related to the use of gas injection; however, the handling capacity has been increased through facility upgrades. Additionally, the ability to inject gas in the BNA Pool will help alleviate gas handling constraints.

Based on its assessment, Staff concurs with the Application from a resource management perspective, and recommend approval.

Operations

Activities in connection with this Application will be managed in accordance with established processes, procedures, and applicable well approvals. Based on this, Operations Staff recommend approval of the Application.

Safety

No safety concerns were identified which would preclude Staff from recommending approval of the Application. Activities in connection with the Application can be managed in accordance with established safety processes and procedures.

Protection of the Environment

There is an existing environmental assessment in place that covers the activity proposed in the Application, therefore Staff concluded that the Application does not require additional environmental assessment pursuant to the Canadian Environmental Assessment Act and recommends approval of the Application. Furthermore, the activity proposed in the Application is covered by the Proponent's existing environmental protection plan.

It is staff's overall assessment that the North Amethyst Development Plan Amendment related to Gas Flood in Support of Oil Production at North Amethyst will enhance oil recover. However, there are four conditions, that have been identified by Board staff:

Condition 1

- **With the exception of G-25 2, should any other oil producer be used for gas flooding operations, a change in well designation will have to be approved by the Chief Conservation Officer (CCO) prior to any gas injection operations being allowed to occur.**

Condition 2

- **That prior to initiating a water-alternating-gas (WAG) scheme in the North Amethyst BNA Pool, 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

- **The Proponent must provide an update on the impacts of removing the Voidage Replacement Ratio (VRR) target of 1.0 to 1.2 from the North Amethyst reservoir management plan in the update to the Resource Management Plan in the North Amethyst Annual Production Report each year. Should the Chief Conservation Officer (CCO) determine at any time that the removal of the VRR target is detrimental to oil recovery the Proponent will be required to revert to a VRR target of 1.0 to 1.2.**

Condition 4

- **Prior to cessation of oil production from the North Amethyst BNA Pool, the Proponent must update the C-NLOPB on its plans for the pool and any wells no longer being utilized. If continued gas injection is planned, the Proponent will be required to apply for a gas storage licence prior to commencing any gas storage operations.**

3. Background

3.1. The Application

On June 29, 2017, the Proponent submitted to the C-NLOPB on behalf of its co-venturers, Suncor Energy and Nalcor Energy – Oil and Gas, the following document:

- North Amethyst Development Plan Amendment – Gas Flood in Support of Oil Production at North Amethyst (June 2017)

Staff reviewed this document for completeness and based on this review requested additional information in a letter dated December 4, 2017. The Proponent responded to this request by submitting the following document on June 5, 2018:

- North Amethyst Development Plan Amendment – Gas Flood in Support of Oil Production at North Amethyst (June 2018).

Staff reviewed this revised document and determined that the document was complete. This document constitutes the Application and is the focus of this review.

3.2. History / Context

The White Rose and North Amethyst fields are located approximately 350 km east of St. John's, Newfoundland and Labrador, on the eastern edge of the Jeanne d'Arc Basin. The White Rose Significant Discovery Area encompasses the White Rose Field, which was discovered in 1984 by the drilling and testing of the Husky et al. White Rose N-22 exploration well, and the adjacent North Amethyst Field, which was discovered in 2006 by the drilling of the Husky Oil et al. North Amethyst K-15 well. The two fields are known collectively as the White Rose Asset Area. Production has been ongoing since 2005 from the White Rose Field and since 2010 from the North Amethyst Field. A map of the White Rose Asset Area including well trajectories is shown in Figure 1.

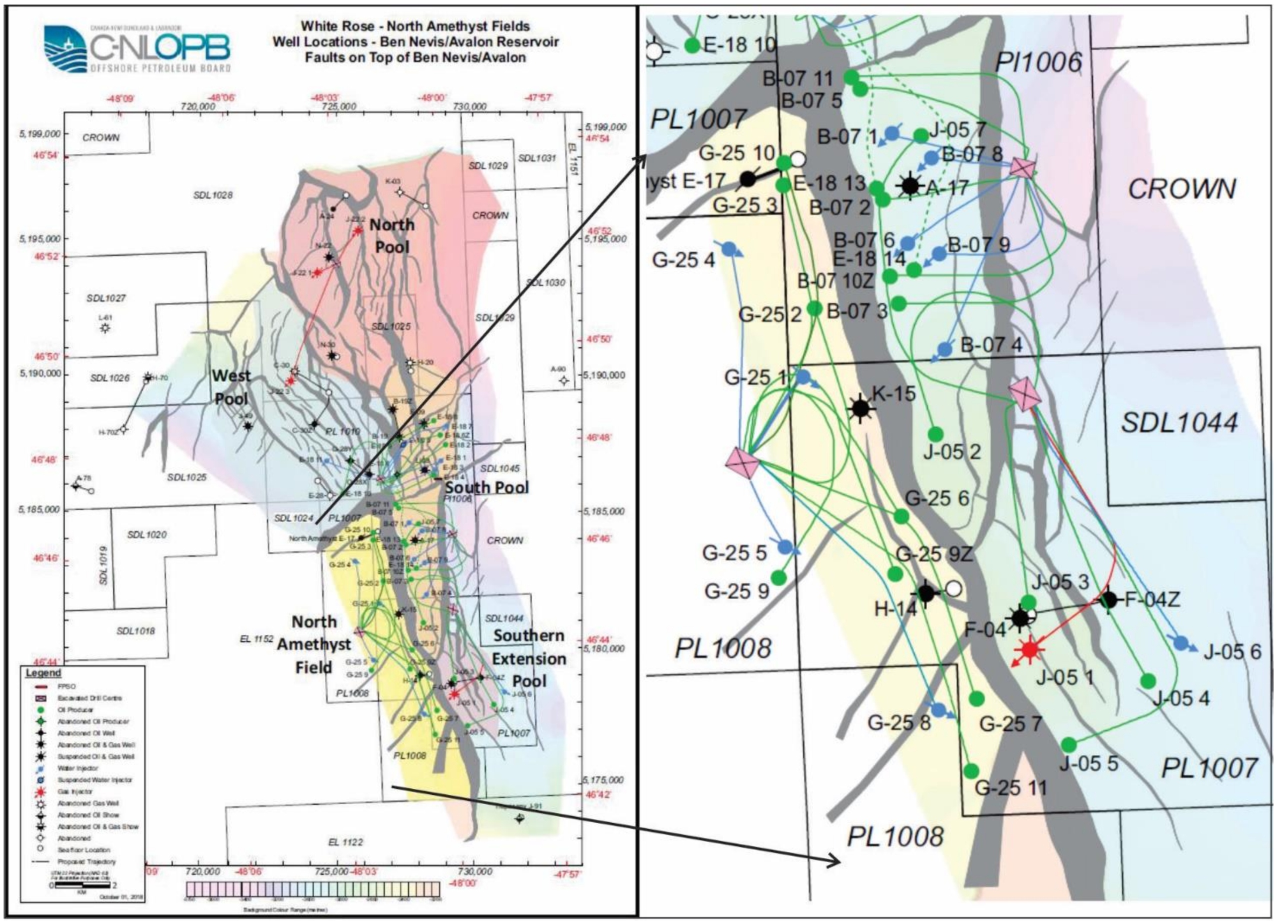

Figure 1: Map of the White Rose Asset area and expanded view of North Amethyst Field wells.

The North Amethyst Field currently sees production from two different pools; the BNA Pool includes the Ben Nevis, Avalon and Eastern Shoals formations, and the deeper Hibernia Pool includes the Hibernia Formation in the E-17 fault block. A total of 12 development wells have been drilled in the North Amethyst Field: eight oil producers and four water injectors, with one water injector completed as a dual injector providing the capability to inject in both the BNA and Hibernia pools. As of September 2018, 8.35 MMm^3 (52.51 MMbbls) of oil have been produced from the North Amethyst Field with 7.87 MMm^3 (49.49 MMbbls) coming from the BNA Pool and 0.49 MMm^3 (3.03 MMbbls) coming from the Hibernia Pool. The production history of the BNA Pool is shown in Figure 2.

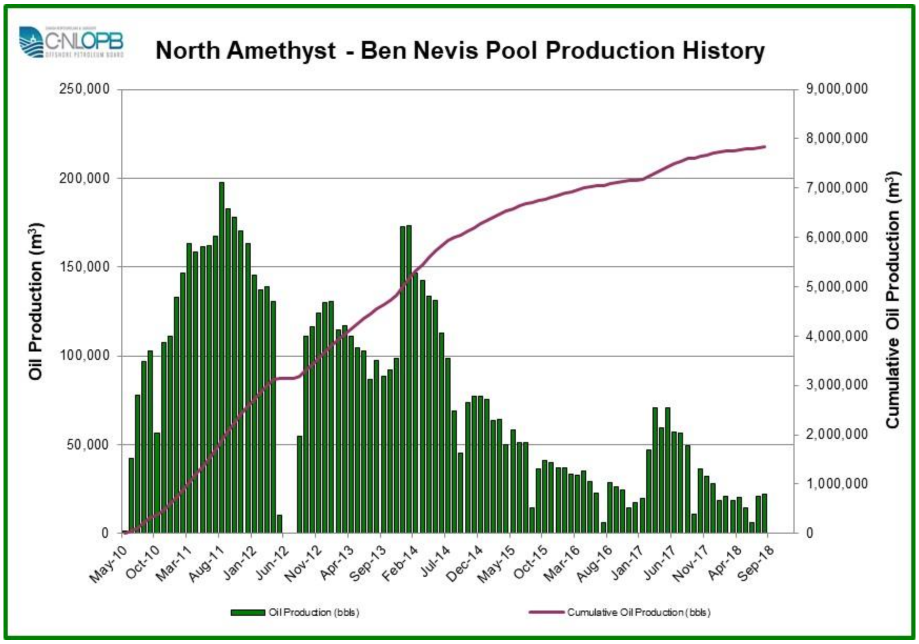

Figure 2: Production history of the BNA Pool at North Amethyst Field.

Both pools have approved development plans for which water flooding was approved as the only secondary recovery mechanism. The Proponent is now requesting to amend the approved development plan for the BNA Pool to allow produced gas to be injected. Gas injection will be used in conjunction with, or as an alternative to, water injection as a means of improving sweep efficiency and providing pressure support. The Application concerns only the BNA Pool; it does not propose gas injection in the Hibernia Pool.

4. Resource Management

4.1. Resource Management Review

Staff reviewed the Application, including the Proponent's seismic interpretation, geological model and reservoir simulation model. Staff also conducted a review of geological, petrophysical and production data acquired since approval of the original North Amethyst Development Plan in 2008 (Decision 2008.03).

Staff did not construct independent geological and reservoir simulation models for assessment of the Application due to other modelling priorities and the minor nature of the proposed change in the depletion scheme. Additionally, because the BNA Pool at North Amethyst is in the late stages of its producing life, with approximately 86 percent of the proven and probable estimated recoverable oil already produced, Staff did not deem a full geological and simulation model build to be justified for review of the Application.

4.2. Geology, Geophysics and Petrophysics

4.2.1. Regional Geology

The Application provides a brief summary of the geologic framework of the North Amethyst Field. The Proponent extensively detailed the regional geologic history of the Jeanne d'Arc Basin in the White Rose Development Plan (Decision 2001.01). Further clarifications regarding nomenclature used in the White Rose Development Plan were noted in the North Amethyst Development Plan (2007), the South White Rose Extension Tie-Back Development Plan Amendment (2012) and the White Rose Extension Project Development Plan Amendment (2014). In consideration of general industry understanding of the basin, these discussions adequately describe the geologic and tectonic evolution of the overall White Rose region and a similar discussion is not required for this Application.

The White Rose Asset is located within a highly faulted complex of rotated fault blocks. It sits on the eastern margin of the Jeanne d'Arc Basin, is 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 consists of shallow marine, fine-grained, quartzose sandstones of the Ben Nevis Formation. This Aptian to Albian-aged succession is interpreted to have been deposited in a southwest-northeast trending shoreface setting with the paleoshoreline located to the east of field (Figure 3).

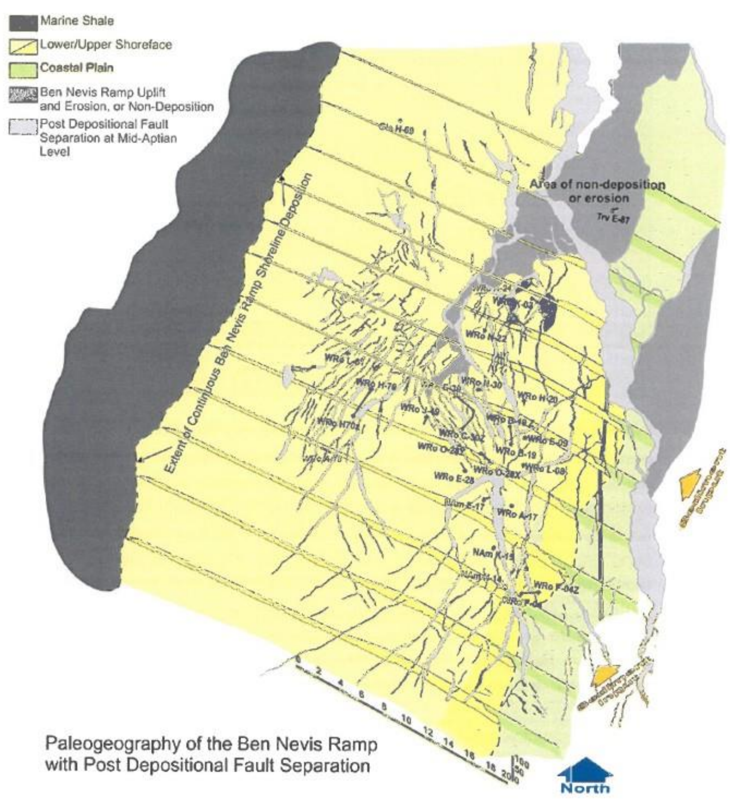

Figure 3: Schematic diagram showing aerial distribution of Ben Nevis shoreface sandstones and related post depositional fault separations. White Rose delineation wells are identified in relation to the paleogeography (Husky, 2018).

4.2.2. North Amethyst Geology

The North Amethyst Field is situated on a large ridge formed by the north-south trending, westerly dipping, rotated fault block adjacent to the Terrace portion of the South Pool of White Rose Field. It is separated from the Terrace by the post-depositional West Terrace Fault which exhibits approximately 600 m of throw. The field is separated from the more structurally complex West Pool of White Rose Field to the north by the North Terrace Fault.

Across most of the White Rose Asset, the Ben Nevis Formation is typically subdivided by marine flooding surfaces and their correlative surfaces that define 13 parasequence sets. However, the North Amethyst Field is located in a proximal setting where many of the marine flooding surfaces are absent. The correlation of the 13 parasequence sets is difficult due to sand-on-sand bed boundaries; therefore, the Ben Nevis Formation is subdivided into 5 sub-zones. The 5 sub-zones are stratigraphically and structurally correlated throughout the field and form the basis of the Proponent's geological model (Figure 4). The six surfaces separating the 5 sub-zones are: the Ben Nevis siltstone (BNEV_SLTST); the Ben Nevis sandstone (BNEV_SS); Marker 1; Marker 2; BNA_300; and the mid-Aptian unconformity (mApt_UC).

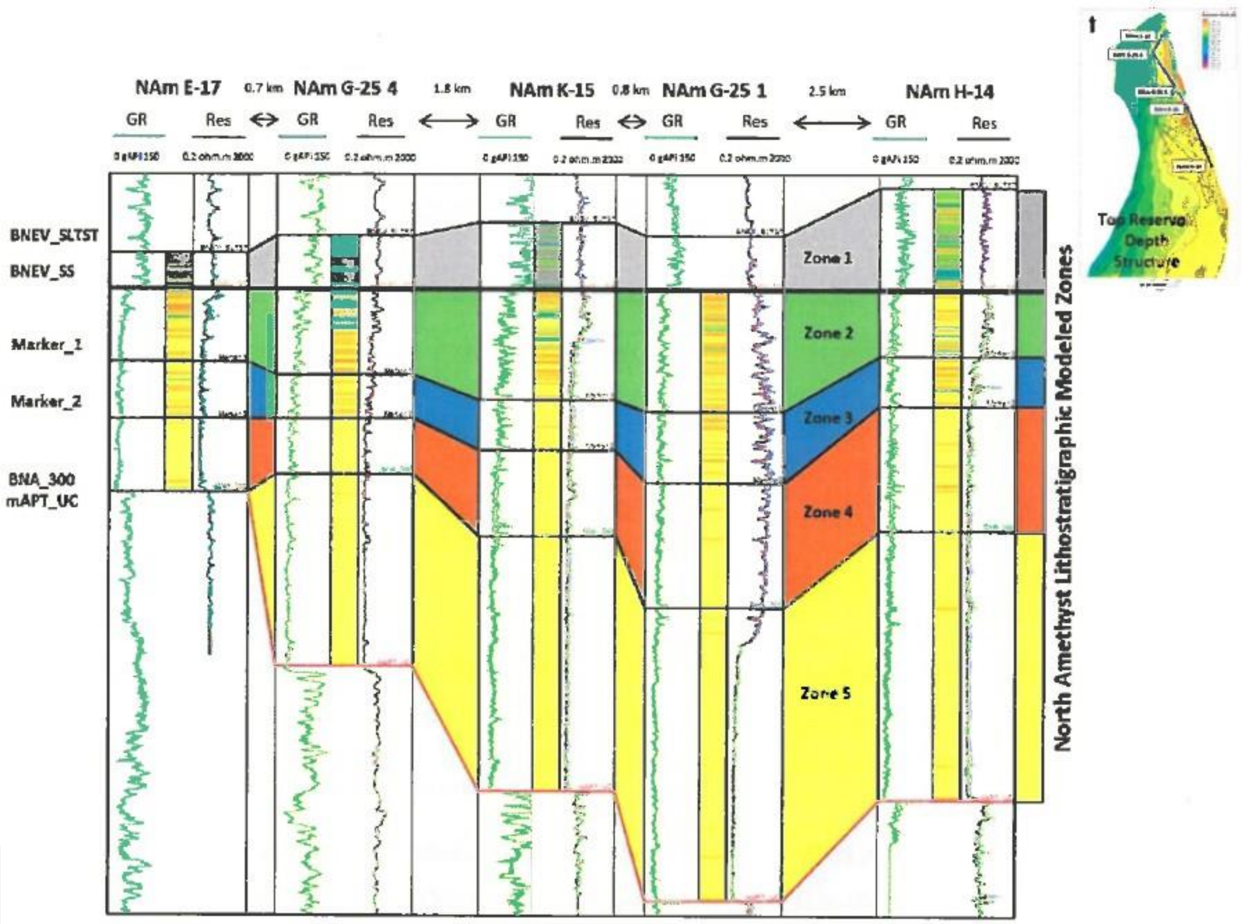

Figure 4: Stratigraphic cross-section showing well correlation across North Amethyst Field (Husky, 2018).

The retro gradational trend observed across the White Rose Asset is evident in the North Amethyst well correlations and interpreted stratigraphic cross-section as sediments fine upwards into interbedded sandstones, siltstones and shale at the top of the Ben Nevis Formation. Calcite concretions that occur throughout the Ben Nevis sandstones increase in frequency within the finer grained rocks near the top of the formation.

The Proponent interprets three main facies associations and several diagenetic components in the Ben Nevis Formation, which are incorporated into the geologic and dynamic models used in simulation:

1) Lower shoreface storm deposits, consisting of well sorted, very fine-grained sandstones with low-angle hummocky to swaley cross-stratified, laminated, massive and parallel laminated structures. Basal scour contacts are associated with bioclastic shell lags with sideritised shale rip-up clasts. These deposits form the main reservoir rock type in the region;
2) Bioturbated lower shoreface fair-weather deposits, consisting of heavily bioturbated siltstone to silty-sandstone to sandstone with rarely preserved primary sedimentary structures; and,
3) Marine deposits, consisting of laminated, massive silty shale to shale with minor bioturbated intervals, representing the most distal component of deposition.

Due to the shallower burial history, diagenetic components are not as prevalent in the reservoir at North Amethyst. However, they are recognized and separated into three groups:

1) Calcite nodules with round edges and likely poor lateral continuity;
2) Slightly more continuous lenticular calcite nodules with convolute edges concentrated in shell lag intervals that are not likely to form intra-reservoir barriers; and
3) Locally present siderite nodules within mud-lined trace fossils.

4.2.3. Geophysics

Staff accepts the details provided in the geophysics section in the Application. Seismic data quality in the White Rose Asset Area is fair to good. The main seismic survey for interpretation in the North Amethyst area was an Anisotropic Pre-Stack Depth Migration volume acquired in 2008 under C-NLOPB program number 8924-H032-007E. The Proponent has provided documentation related to the geophysical data, processing and interpretation in various products submitted to the C-NLOPB.

The 2008 survey aimed at improving fault interpretations and resolving internal Ben Nevis seismic horizons and deeper prospective intervals. Older vintage seismic data were used and processed concurrently with the 2008 data to fill data gaps due to obstacles such as the FPSO, and areas that were not surveyed due to poor weather conditions. Staff reviewed this seismic data and believes this approach to be appropriate. However, issues such as interbed multiples, presence of Tertiary anomalies and complex faulted regions still remain.

Improved seismic resolution and integration of delineation and development wells has decreased the structural uncertainty at North Amethyst. The most challenging aspects of seismic interpretation are the low impedance contrast between the Ben Nevis sandstone and surrounding geology, as well as fault complexity in the region.

Two seismic horizons were interpreted over the North Amethyst area, the BNEV_SS (Top Ben Nevis sandstone) surface and the mApt_UC or Mid-Aptian Unconformity (base Ben Nevis). The BNEV_SS seismic marker is interpreted as the ‘top sandstone’ marker and picked as a fairly continuous, low-amplitude trough that can be mapped over the entire North Amethyst area. The BNEV_SS reflector is affected by multiples and is also difficult to follow in highly faulted areas. In general the mApt_UC is a medium- to high-reflectivity peak, but the amplitude decreases in areas and changes polarity as it truncates packages of rock with different impedance properties. For example, where the Mid-Aptian Unconformity erodes the high impedance A-marker there is a tuning effect, particularly when the BNA_RAMP thins below seismic resolution. A strong peak is interpreted where the Mid-Aptian marker is a combination of RAMP sand, Mid-Aptian and A-Marker. The Proponent’s interpreted depth structure maps for the top Ben Nevis sandstone and mid-Aptian unconformity are shown in Figure 5.

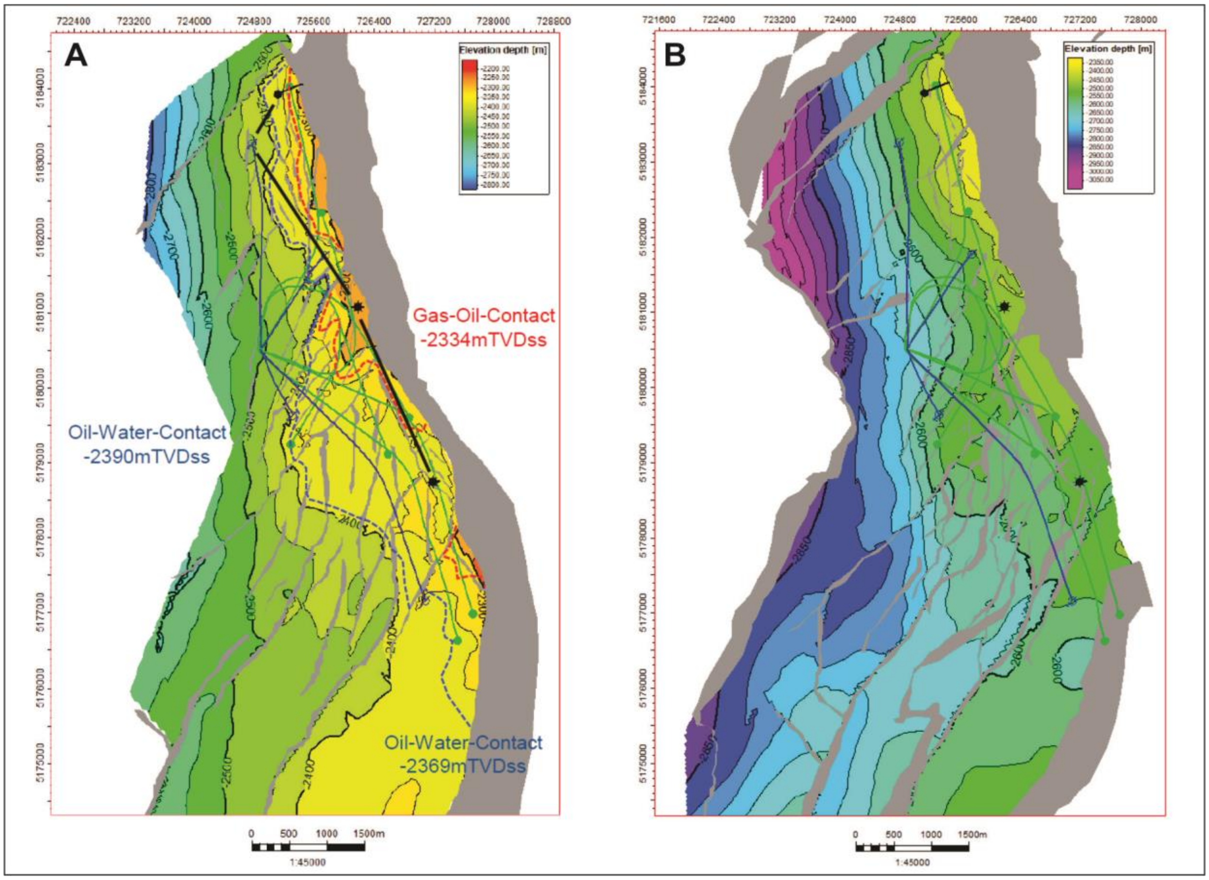

Figure 5: (A) Top reservoir depth structure map (Ben Nevis sandstone), and (B) Base reservoir depth structure map (mid-Aptian Unconformity; Husky 2018).

4.2.4. Petrophysics

The Proponent conducted a comprehensive logging and coring program while drilling the exploration, delineation and development wells in North Amethyst Field. In the Application, the Proponent’s petrophysical interpretation of the Ben Nevis reservoir is summarized for all wells in the approved development area of the field. The Proponent supplied supplemental information on the methodology, assumptions and criteria used in the petrophysical analysis.

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

4.2.5. Reservoir Geologic Modelling

Staff accepted the Proponent's static reservoir geological model. An independent model has not been generated by Staff since work conducted to complete the 2008 Staff Analysis of the North Amethyst Satellite Tie-Back Project. At the time the original North Amethyst Field Development Plan was submitted, there was one exploration well, North Amethyst K-15. Subsequent delineation and development drilling confirmed the presence of hydrocarbons and enhanced understanding of the Ben Nevis reservoir.

The Proponent detailed the evolution of the North Amethyst Field geological model based on the drilling results since 2007 in the subsequently submitted Annual Production Reports. The Q4 2015 North Amethyst Field geological model version is the basis for the model submitted in support of this Application.

The Proponent provided gross thickness and net thickness maps based on the Ben Nevis sandstone reservoir model (Figure 6). Figure 7 represents the Proponent's well log data for VSH_GR, porosity and water saturation, as well as facies determinations based on cut-offs. Overall there is a good match between the log response and layering used to represent the petrophysical variation within the zones of the submitted geological model.

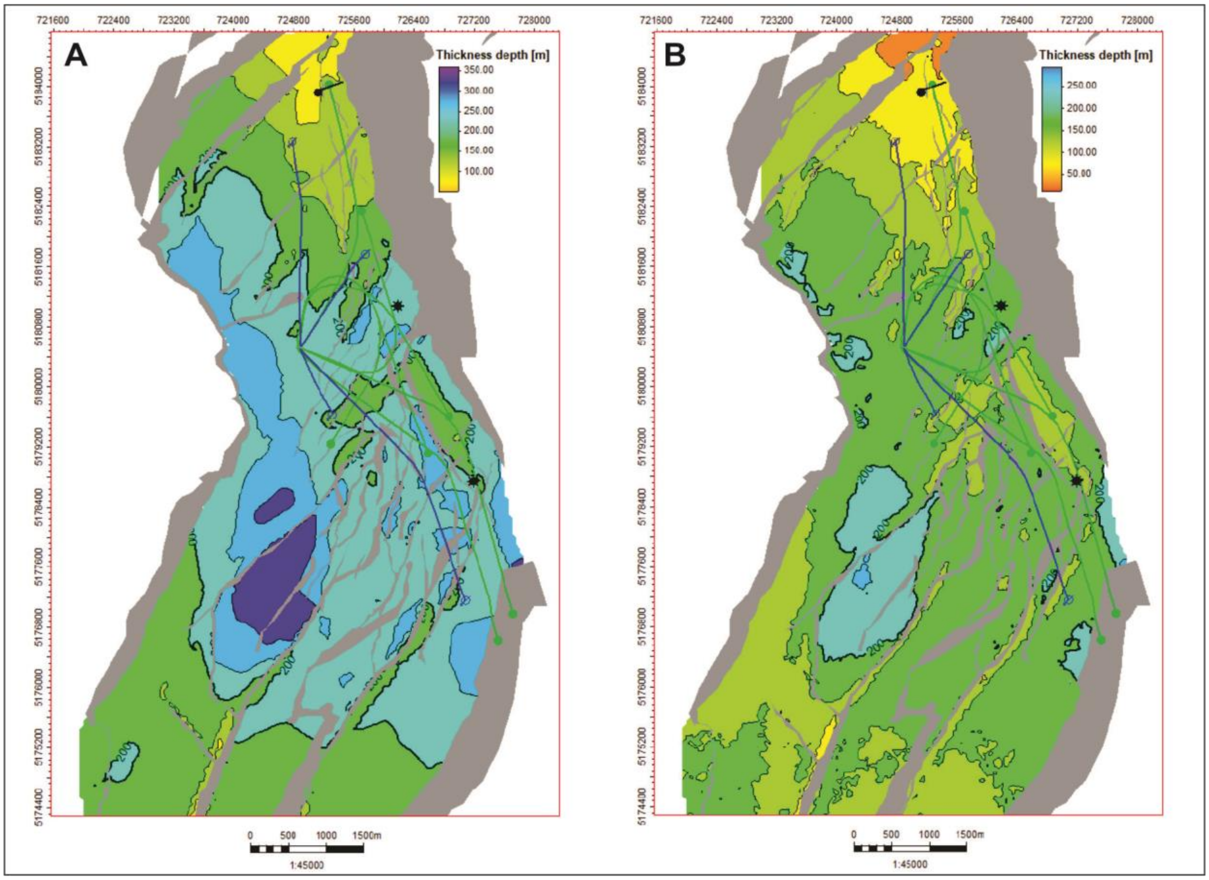

Figure 6: Proponent's Ben Nevis sandstone reservoir gross thickness (A), calculated from BNEV_SS and mApt_UC modeled horizons; and modeled net thickness (B) of Ben Nevis sandstone reservoir Laminated Sand facies, using applied reservoir cut-offs (>10% porosity and <30% clay; Husky, 2018).

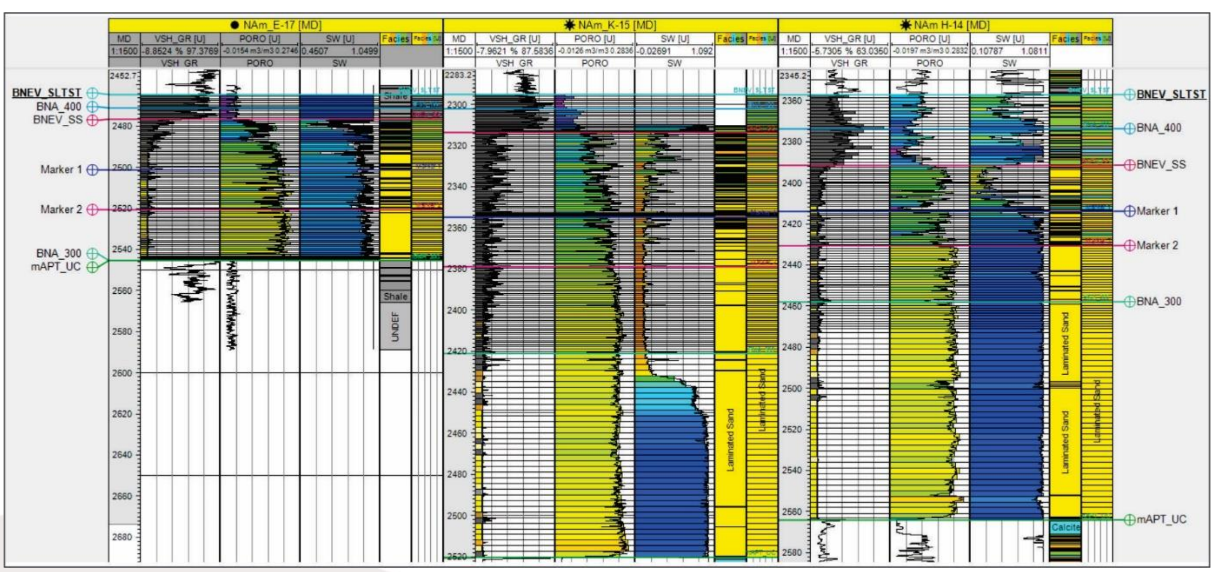

Figure 7: Exploration and delineation well log data compared to the upscaled cells in the Proponent's geological model.

4.3. Oil and Gas in Place

As previously stated, Staff has not constructed a geological model to assess the Application. Therefore, no independent assessment of the hydrocarbon-in-place volumes is possible at this time. The latest C-NLOPB model was described in the Staff Analysis of the original North Amethyst Development Plan (Decision 2008.03).

Since 2008, the Proponent has acquired new geophysical data and petrophysical data from delineation and development drilling that have enhanced the understanding of the BNA Pool. The Proponent used the newly acquired data to update the static reservoir model and resulting volumetric estimates. These updates were described in Annual Production Reports submitted to the C-NLOPB.

Staff accepts that the Proponent's static model has evolved since 2008, and therefore concurs with the Proponent's presented current estimates of stock-tank original oil in place (STOOIP) and gas initially in place (GIIP; Table 1). The estimates are based on the latest Q4 2015 geological model that incorporates delineation and development drilling in the North Amethyst Field, with the exception of the G-25 10 and G-25 11 wells. Estimates will likely change with future understanding of field performance. The Proponent's hydrocarbon pore volume maps for oil and gas are provided in Figure 8.

Table 1: Proponent's and C-NLOPB's resource estimates in the BNA Pool at North Amethyst.

		Units	P90	P50	P10
STOOIP	**C-NLOPB 2008**	MMm^3	34	40	46
		MMbbls	213	251	288
	Husky 2008	MMm^3	**34**	**41**	**49**
		MMbbls	**211**	**259**	**310**
	Husky 2018	MMm^3	**22.1**	**26.6**	**31.0**
		MMbbls	**138.8**	**167.5**	**195.2**
Free Gas GIIP	**C-NLOPB 2008**	Bm^3	4.2	4.9	5.5
		BCF	147	173	216
	Husky 2008	Bm^3	**3.2**	**4.2**	**5.9**
		BCF	**114**	**149**	**210**
	Husky 2018	Bm^3	**1.09**	**1.32**	**1.54**
		BCF	**38.5**	**46.7**	**54.4**
Solution Gas GIIP	**C-NLOPB 2008**	Bm^3	6.1	8.7	11.4
		BCF	216.5	308.8	404.6
	Husky 2008	Bm^3	**3.5**	**4.2**	**5.1**
		BCF	**122**	**150**	**181**
	Husky 2018	Bm^3	**2.22**	**2.68**	**3.12**
		BCF	**78.4**	**94.6**	**110.3**

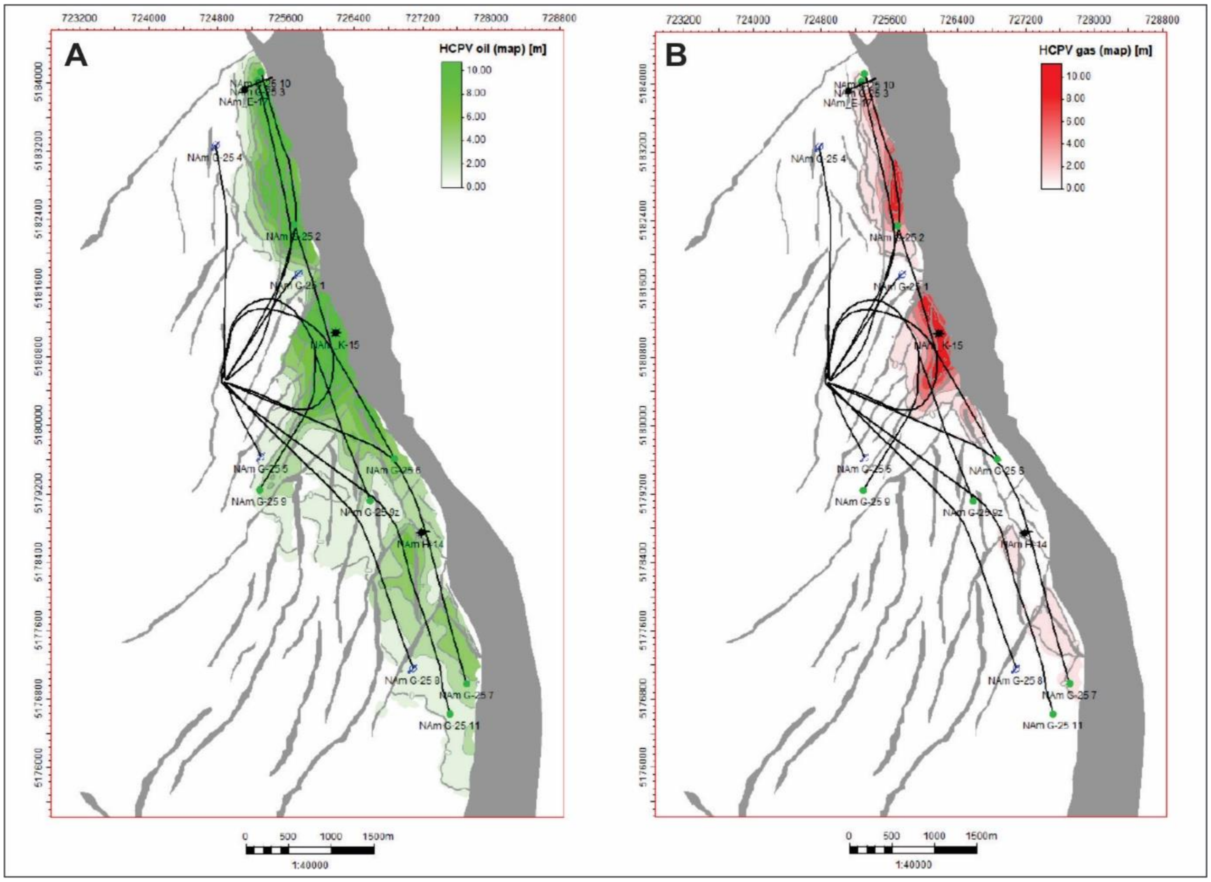

Figure 8: Mapped property value of hydrocarbon pore volume per unit area for oil (A) and gas (B) (Husky, 2018).

4.4. Reservoir Engineering

Analysis of the reservoir engineering component of the Application included a review of the following items:

- Reservoir pressure
- Reservoir temperature
- Fluid characterization
- Special core analysis (SCAL)

4.4.1. Reservoir Pressure

The original North Amethyst development plan outlined a GOC of -2334 m TVDss and an OWC of -2390 m TVDss for the BNA Pool. These contacts were determined through analysis of the pressure-versus-depth data acquired by Schlumberger's modular dynamic formation tester tool (MDT) on the K-15 discovery well.

Subsequent delineation and development drilling verified these contacts over most of the North Amethyst Field; however, a second GOC and OWC were also identified. The G-25 9 well encountered a second GOC in the reservoir at a depth of -2363 m TVDss and the G-25 7 well encountered a second

OWC at -2369 m TVDss in the southern region of the pool. A pressure-versus-depth plot for the BNA Pool is illustrated in Figure 9.

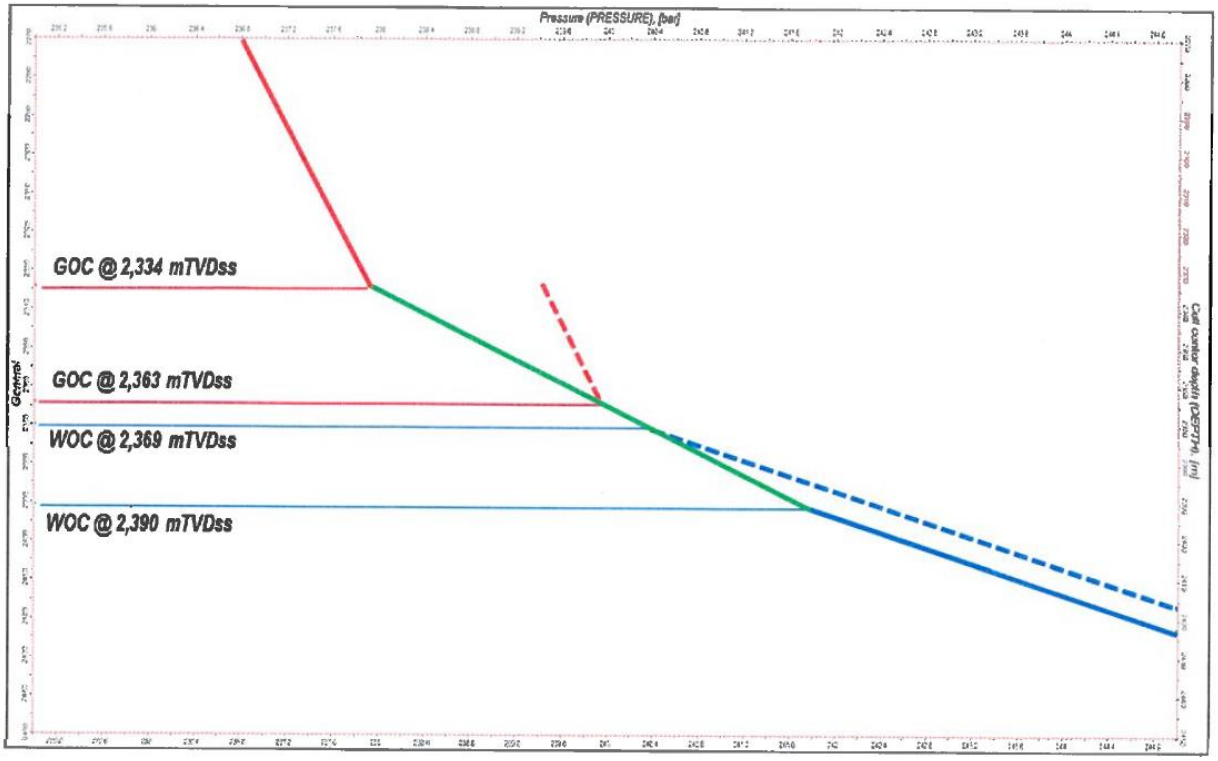

Figure 9: North Amethyst pressure profile (Husky, 2018).

Staff has reviewed the Proponent's interpretation of reservoir pressure data and conducted an independent assessment. The interpretation presented in the Application is considered to be reasonable and appropriate.

4.4.2. Reservoir Temperature

Due to the number of wells, the reservoir temperature and temperature gradient data for the North Amethyst BNA Pool is well understood. Staff has reviewed the Proponent's interpretation and considers the temperature data presented to be reasonable. The temperature profile for the BNA Pool is shown in Figure 10.

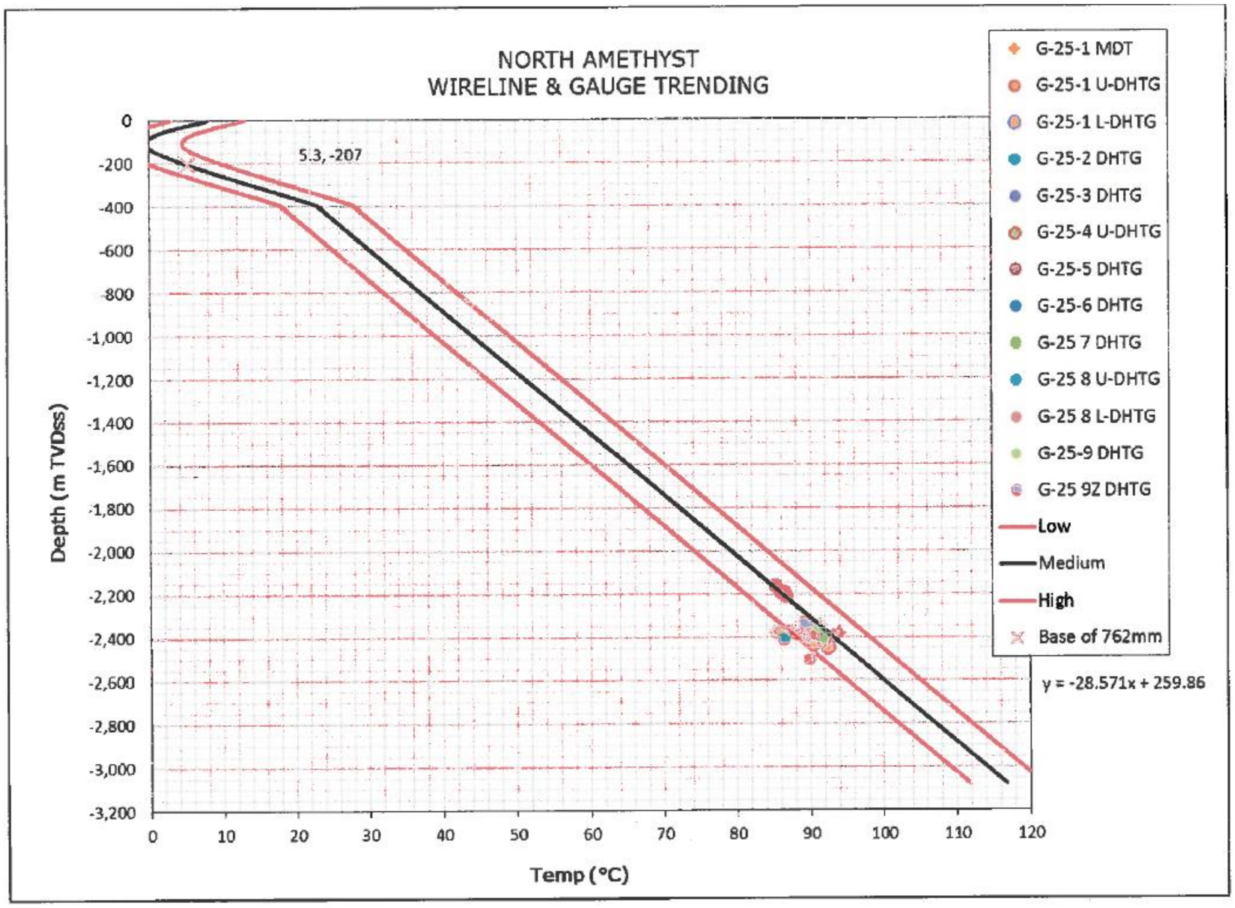

Figure 10: North Amethyst temperature profile (Husky, 2018).

4.4.3. Fluid Characterization

A full suite of reservoir samples from the BNA Pool was collected in the K-15 discovery well. Six oil samples, three gas samples and three water samples were recovered. The results of various fluid analyses performed on these samples were described in the original development plan.

Since that time, the Proponent has observed that other fluid samples in the field showed contamination from the use of oil-based mud (OBM). The OBM filtrate is soluble in the reservoir fluids, which can lead to inaccurate results from laboratory analysis. Following a review of the original K-15 samples, the Proponent updated the reservoir fluid characterization to account for OBM contamination. Reservoir fluid properties that were impacted include saturation pressure, formation volume factor and initial gas-oil ratio (GOR). The updated reservoir fluid characterization indicates a saturation pressure of 23.79 MPa, formation volume factor of 1.3227 rm^3/sm^3 and an average initial GOR of 100.64 m^3/m^3.

The PVT properties for gas used in simulation remain unchanged from the Development Plan submission and are shown in Table 2.

Table 2: North Amethyst K-15 gas PVT data (Husky, 2018).

	N-30	J-22 1	J-22 1	F-04	K-15
Sample Type	Bottom Hole - MDT	Bottom Hole - MDT	Recombined Sep	Bottom Hole - MDT	Bottom Hole - MDT
Sample ID	248-06	MPSR 1359	1206 / 14002-QA	MPSR 1363	MPSR 1476
Sample Depth (m MD)		2851.3	Separator	2826.8	2375
Mud System	WBM	SBM	SBM	WBM	SBM
Reservoir Temp (°C)	106	106	106	101	88
Dew Point (kPa)	30,660	30,340	28,463	29,470	21,970
Z Factor*	0.9728	0.9131	0.9740	0.9250	0.9044
Viscosity (cP)*	0.0252	0.0240	n/a	0.0243	0.0201
Density (g/cm3)*	0.2141	0.2256	0.1860	0.2044	0.1641
MW	21.41	21.40	20.48	20.96	20.64
CGR (m^3 / 10^6m^3)	182.75	183.52	159.74	150.73	102.6
CGR (stb/mmscf)	32.55	32.69	28.46	26.85	18.27
N_2 mole fraction	0.0013	0.0037	0.0052	0.0052	0.0052
CO_2 mole fraction	0.0153	0.0130	0.0108	0.0134	0.0161
H_2S mole fraction	0.0000	0.0000	0.0000	0.0000	0.0000
C1 mole fraction	0.8924	0.8787	0.8819	0.8743	0.8813
C2 mole fraction	0.0389	0.0412	0.0429	0.0431	0.0398
C3 mole fraction	0.0185	0.0215	0.0230	0.0241	0.0198
i-C4 mole fraction	0.0032	0.0033	0.0035	0.0039	0.0031
n-C4 mole fraction	0.0074	0.0097	0.0087	0.0096	0.0077
i-C5 mole fraction	0.0015	0.0018	0.0024	0.0023	0.0022
n-C5 mole fraction	0.0024	0.0030	0.0034	0.0036	0.0029
$C6^+$ mole fraction	0.0191	0.0241	0.0183	0.0205	0.0218
$C6^+$ MW	183.40	138.46	n/a	127.94	117.88
$C6^+$ density (g/cm^3)	0.8417	0.7920	n/a	0.7700	0.7752

*property at dew point at reservoir temperature.

Staff agrees that the updates made to the reservoir fluid characterizations by the Proponent are reasonable and appropriate.

4.4.4. Special Core Analysis (SCAL)

The oil-water and gas-oil relative permeability curves used for the BNA Pool are based on relative permeability testing that was conducted using stacked plugs and full diameter core samples obtained from the K-15 well. The endpoints of the laminated sandstone normalized relative permeability curves are presented in the Application and were used by the Proponent in the reservoir simulation model.

Staff considers the Proponent's approach of incorporating SCAL data to be acceptable.

4.5. Development Strategy

Initial development of the BNA Pool consisted of four horizontal oil producers and one multilateral oil producer, with pressure support provided by four water injectors located down dip.

Following execution of the initial phase, the Proponent identified improved oil recovery (IOR) opportunities up dip of the current oil producers. The first opportunity implemented was an infill oil producer, G-25 10, which was drilled to target attic oil in the northern part of the pool. This well was brought online in February 2017. The second opportunity was another infill well, G-25 11, that was drilled to target attic oil in the southern portion of the field. This well was brought online in March 2018. Figure 1 shows all current development wells in the North Amethyst Field.

To further improve oil recovery, the Proponent is now proposing to implement gas flooding in the BNA Pool. Two base-case options for implementing gas flooding have been outlined, both of which may or may not be implemented. The two options are:

1) A conventional gas injector drilled into the BNA Pool gas cap from the SWRX drill centre or the West White Rose Wellhead Platform (Figure 11); and,
2) Gas flood implemented through existing North Amethyst oil producers via the existing subsea gas-lift infrastructure.

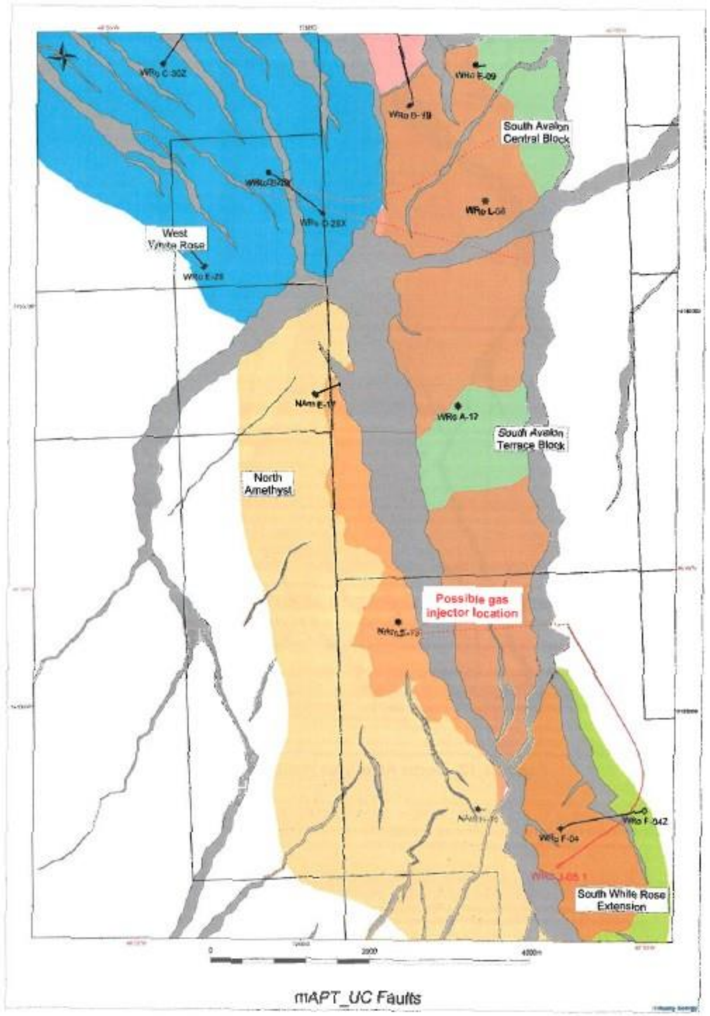

Figure 11: Possible location of gas injector drilled from SWRX drill centre (Husky, 2018).

Due to the time and cost required to drill a dedicated gas injector, the Proponent has indicated to the C-NLOPB that the most likely scenario to be implemented initially is gas flooding through existing North Amethyst oil producers via the existing gas lift infrastructure. It is also expected that the G-25 2 oil producer, which has reached its economic limit due to water cut, will be the first well utilized. The Proponent has indicated that any future producers that will be used for gas flooding will also have reached the economic limit. Staff notes that any such change in well designation would have to be approved by the Chief Conservation Officer (CCO) prior to any gas injection operations being allowed to occur.

Condition 1: With the exception of G-25 2, should any other oil producer be used for gas flooding operations, a change in well designation will have to be approved by the Chief Conservation Officer (CCO) prior to any gas injection operations being allowed to occur.

Staff agrees with the Proponent's proposed next stage of the IOR plan. To date, water flooding has been an effective means of providing pressure support while simultaneously providing bottoms-up oil displacement. However, due to the nature of this drive mechanism and of the Ben Nevis reservoir, a large portion of the cellar oil between the down-dip water injectors and the existing producers has been swept, leaving the most significant remaining resource potential in the attic area of the reservoir between the producers and the GOC. Gas flooding has the potential to expand the gas cap and push this attic oil to the down-dip producers, improving overall recovery of the BNA Pool.

In addition to the two base-case options, the Proponent is also seeking approval for two alternative methods of providing gas flood in the BNA Pool which are currently being evaluated:

1) Gas cap Water-Alternating-Gas (WAG) injection wells via the West White Rose Wellhead Platform; and,
2) Conversion of existing wellbores for WAG injection.

Staff is encouraged by the Proponent's continuous evaluation of other methods to improve sweep efficiency and EUR; however, no simulation modelling or other technical analysis in support of these options was provided with the Application. Staff is not opposed to the Proponent implementing these schemes, as the practice of routinely assessing enhanced oil recovery schemes is consistent with the requirements of the Newfoundland Offshore Petroleum Drilling and Production Regulations. However, before the Proponent may proceed with WAG injection, simulation modelling or some other form of technical analysis should be provided to the C-NLOPB to demonstrate that there will be no detriment to oil recovery.

Condition 2: That prior to initiating a water-alternating-gas (WAG) scheme in the North Amethyst BNA Pool, 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.

4.5.1. Reservoir Management Plan

The original reservoir management plan for the BNA Pool consisted of secondary recovery and pressure support through water flooding. Under this plan the Proponent has strived to achieve a target voidage replacement ratio (VRR) of 1.0 to 1.2 to maintain reservoir pressure at or above the saturation pressure.

The Application proposes altering the reservoir management plan to remove the 1.0 to 1.2 VRR target, which the Proponent indicates will enable both production optimization of the various producers and maximum recovery of the mature BNA Pool.

Staff is encouraged by the Proponent's efforts to maximize recovery from the pool, but there are concerns with the potential for extended periods of production below saturation pressure. Best practice in the petroleum industry is to produce above the saturation pressure when feasible. However, due to recent production trends and the low remaining recoverable oil reserves, Staff does see merit in providing the Proponent with the flexibility to try to optimize oil recovery while simultaneously injecting water and gas. Staff's reasoning for this is based on the following factors:

- The BNA producers are considered to be late in their producing lives with all of the current producing wells ranging from 80 to 90 percent water cut. The first producer to come online in North Amethyst, G-25 2, has been shut in since December 2017 when it reached 97 percent water cut. Additionally, after the first IOR infill producer, G-25 10, came online in February 2017 water cut developed more aggressively than anticipated, reaching 92 percent as of September 2018. These factors indicate that the oil accumulation down dip of the producers has been well swept with minimal oil in place remaining. As a result, the largest remaining recoverable oil potential in the BNA Pool is thought to be the attic oil located between the producers and the up-dip GOC. As the Proponent indicates in the Application, maintaining a voidage strategy that results in continued increase in water cut, while not effectively exploiting the remaining attic oil, may not be the best approach for extending field life and increasing ultimate recovery.

- Gas flooding of the BNA Pool is expected to enable increased oil recovery because it will result in expansion of the gas cap and will help to sweep the remaining attic oil down dip to the producers. Having the flexibility to change the VRR target will provide the Proponent with several other options for exploiting the attic oil. Through production monitoring and testing, in conjunction with simulation studies, the Proponent will eventually determine the optimal recovery strategy under simultaneous water flood and gas flood.

- The Proponent ceased or restricted water injection in North Amethyst for extended periods of time leading into FPSO maintenance turnarounds in 2016, 2017 and 2018, in an attempt to limit the production impairment to the producers from being shut in for an extended period of time. During each of these periods of low voidage replacement, measured water cut or water-cut progression was lower than expected, while gas production and GOR development at the producers changed only minimally. Furthermore, reservoir pressure decline during these low voidage replacement periods was observed to be less severe than would be expected from a closed-tank reservoir. The Proponent is still evaluating, but early technical work suggests that an active aquifer is providing support to the reservoir. This was accounted for in current voidage replacement calculations.

- A number of simulation cases assessing the impact of under-voiding the reservoir were provided with the Application. These cases did not show an appreciable difference in the ultimate oil recovery when compared to the cases where a VRR of 1.0 or greater was targeted.

Taking these points into account, Staff agrees with the proposal to revise the reservoir management plan to remove the targeted VRR of 1.0 to 1.2. However, the Proponent should be required to submit an update on the performance of this revised reservoir management plan in the update to the Resource Management Plan in the Annual Production Report each year. Should the CCO determine at any time that the revised plan is detrimental to oil recovery, the Proponent will be required to revert to the originally approved VRR target of 1.0 to 1.2.

Condition 3: The Proponent must provide an update on the impacts of removing the Voidage Replacement Ratio (VRR) target of 1.0 to 1.2 from the North Amethyst reservoir management plan in the update to the Resource Management Plan in the North Amethyst Annual Production Report each year. Should the Chief Conservation Officer (CCO) determine at any time that the removal of the VRR target is detrimental to oil recovery the Proponent will be required to revert to a VRR target of 1.0 to 1.2.

4.5.2. Injection Fluids

Currently, the North Amethyst Field is produced using injected seawater from the *SeaRose FPSO*. Density and composition of the injected water is provided in Table 3.

Table 3: Injected seawater analysis (after Husky, 2018).

Density	kg/m^3	1024
Chemical Component		
Na	mg/L	9772
K	mg/L	351
Ca	mg/L	438
Mg	mg/L	1167
Cl	mg/L	17,498
HCO_3	mg/L	128
SO_4	mg/L	1922

Under this Development Plan Amendment, the Proponent is now planning to develop the BNA Pool through both water and gas injection. The composition of the gas to be injected is included in Table 4.

Table 4: Injected gas composition (after Husky, 2018).

Gas Component	Mole Fraction
CO	0.0001
H_2	Trace
He	0.0001
O_2	0.0028
N_2	0.0135
CO_2	0.0208
H_2S	0.0000
C_1	0.8509
C_2	0.0554
C_3	0.0318
iC_4	0.0045
nC_4	0.0106
iC_5	0.0025
nC_5	0.0031
C_6	0.0021
C_7	0.0011
C_8	0.0007
C_9	Trace
C_{10}	0.0000
Total	**1.0000**

Specific Components	Mole Fraction
neo-Hexane (C_6)	0.00000
n-Hexane (C_6)	0.00084
Methylcyclopentane (C_7)	0.00043
Benzene (C_7)	0.00023
Cyclohexane (C_7)	0.00035
2,2,4-Trimethylpentane (C_8)	0.00000
Methylcyclohexane (C_8)	0.00019
Tolulene (C_8)	0.00000
Ethylbenzene (C_9)	Trace
m&p-Xylene (C_9)	0.00000
o-Xylene (C_9)	Trace
1.2.4-Trimethylbenzene (C_{10})	0.00000
Plus Components	
C_7^+	0.00180
C_{12}^+	0.00000
C_{15}^+	0.00000

4.5.3. North Amethyst and Full Field Performance Forecast

Production from North Amethyst Field is currently processed on the *SeaRose FPSO*. The Proponent conducted an assessment to ensure the processing facilities are capable of handling the increased production volumes resulting from the revised depletion strategy. As this Application only proposes the addition of gas flood, the incremental volumes are not expected to be significant. The production and injection constraints used for the assessment were:

- 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 – 5.5 MMm^3/day (194 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, water production, liquid production, gas handing , gas injection, gas lift and water injection. These profiles were generated with consideration of well scheduling, annual turnarounds/off-station programs and simulation results. The resultant profiles were included with the Application and are shown in Figure

12 to Figure 21. It is worth noting that the Proponent has recently increased the capacity of the gas compression system from the previous limit of 4.2 MMm³/day to the current capacity of 5.5 MMm³/day. This increase was made possible by upgrades to various facility equipment as well as a change in operating pressure of the high pressure separator. The Proponent believes these changes will better position the facility for future developments.

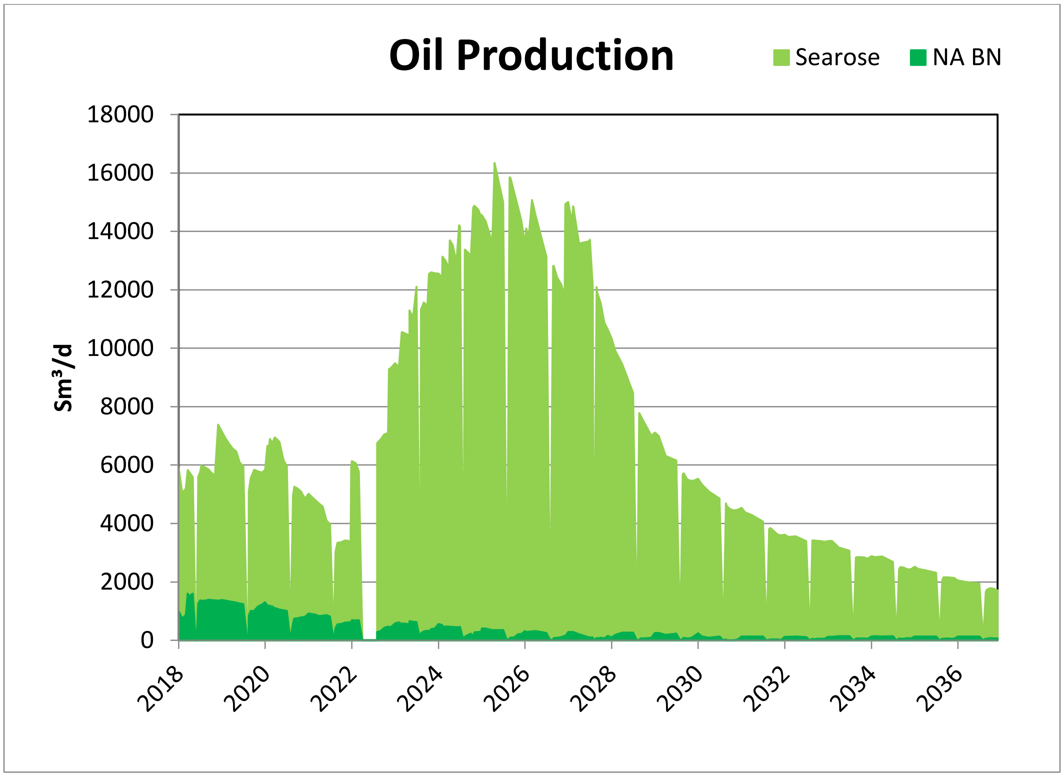

Figure 12: Full-field oil production profile (Husky, 2018).

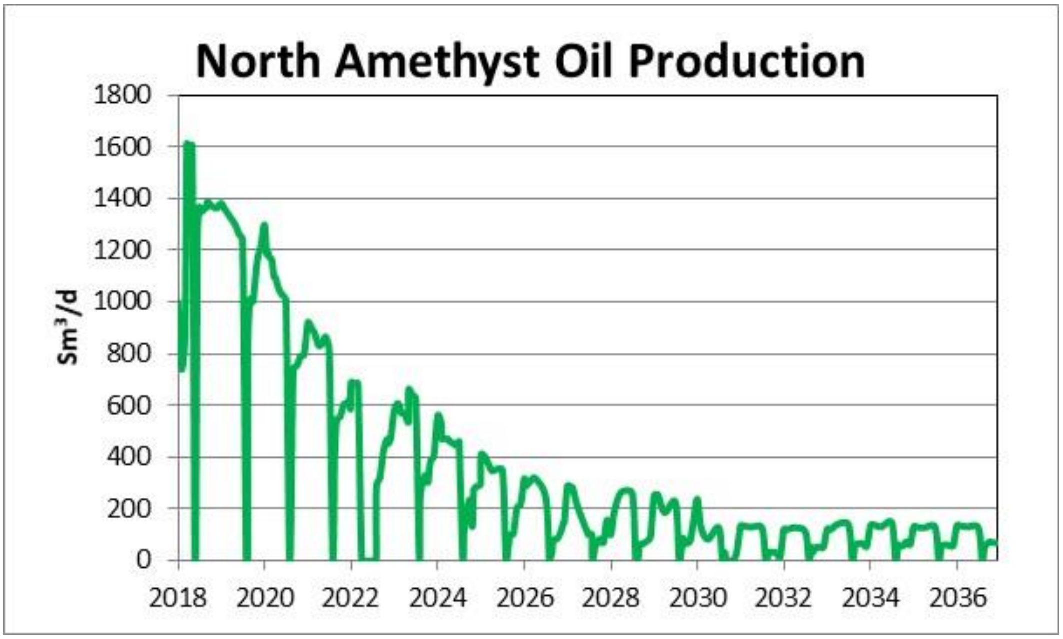

Figure 13: North Amethyst oil production profile (Husky, 2018).

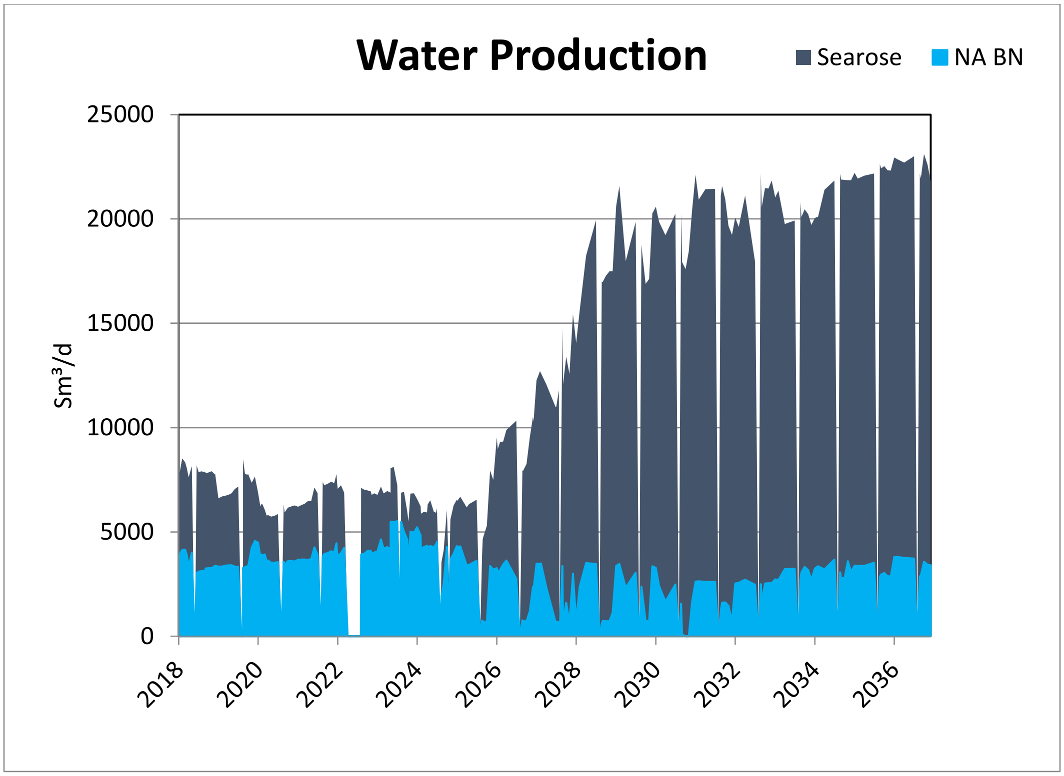

Figure 14: Full-field water production profile (Husky, 2018).

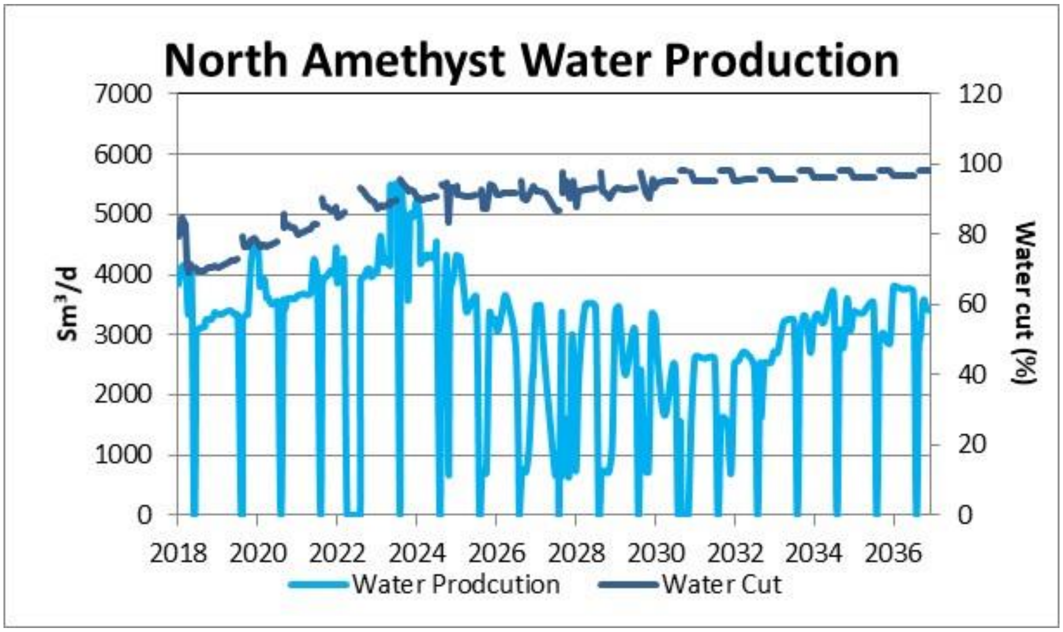

Figure 15: North Amethyst water production profile (Husky, 2018).

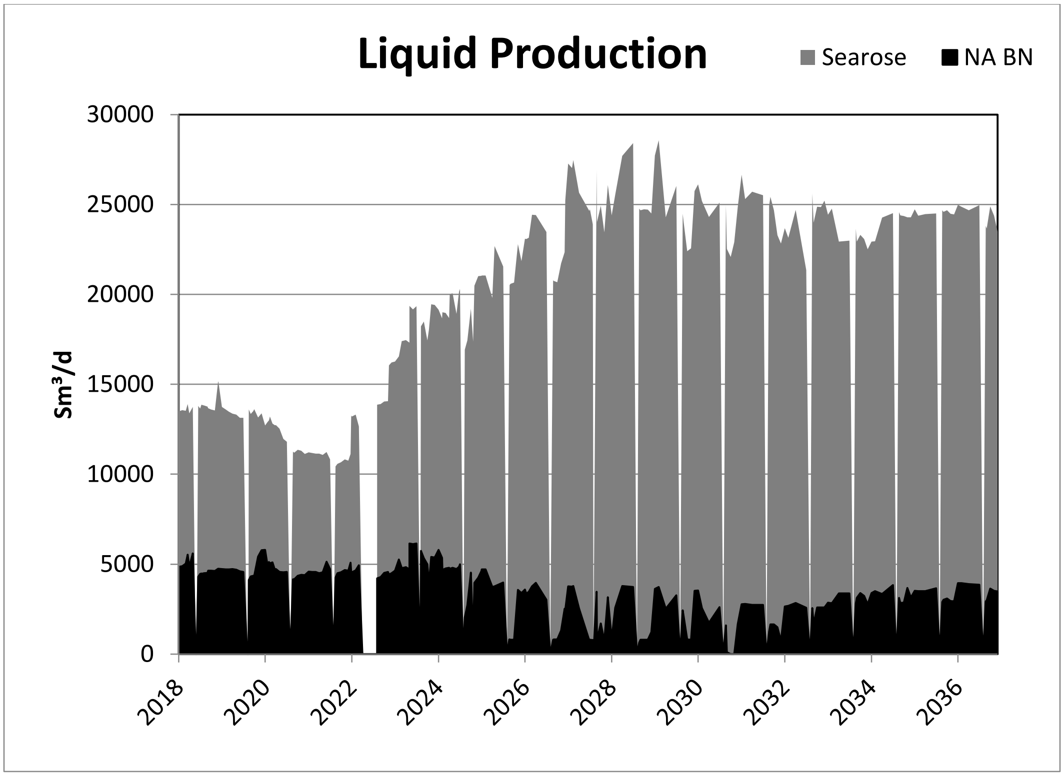

Figure 16: Full-field liquid production profile (Husky, 2018).

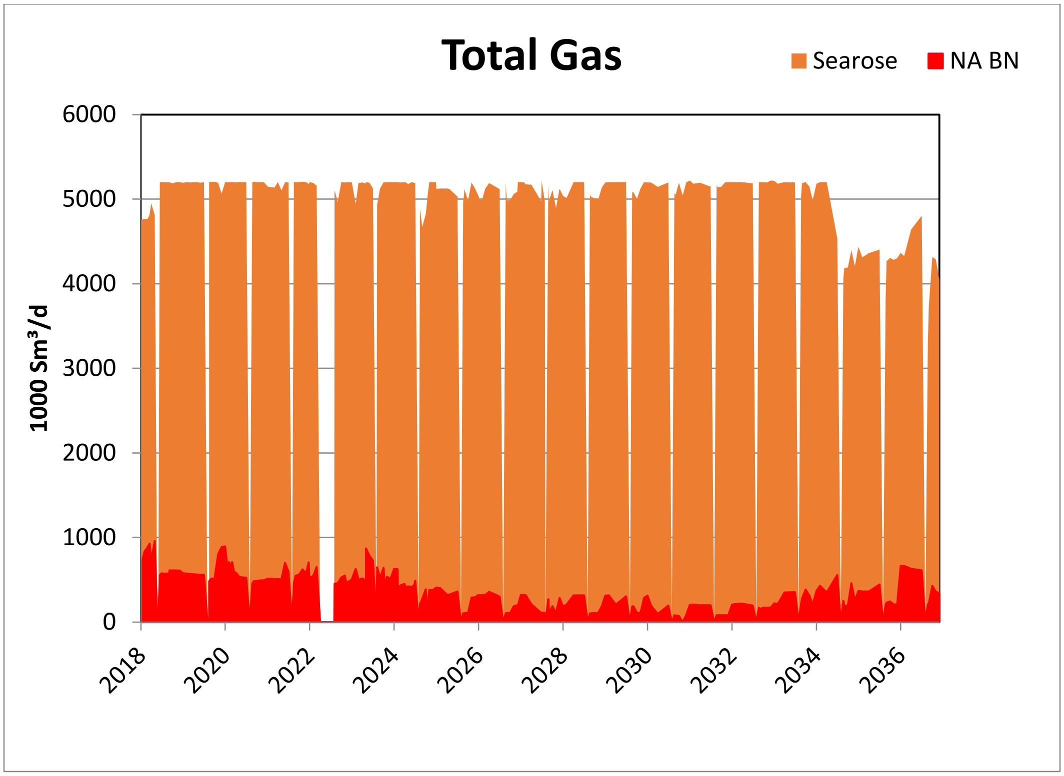

Figure 17: Full-field gas handling profile (Husky, 2018).

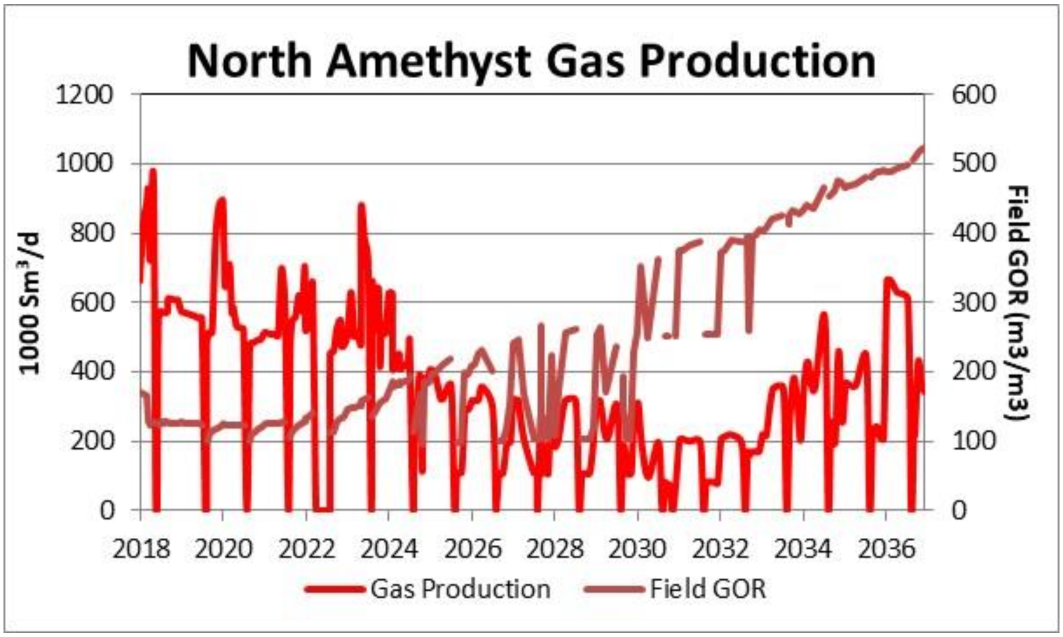

Figure 18: North Amethyst gas production profile (Husky, 2018).

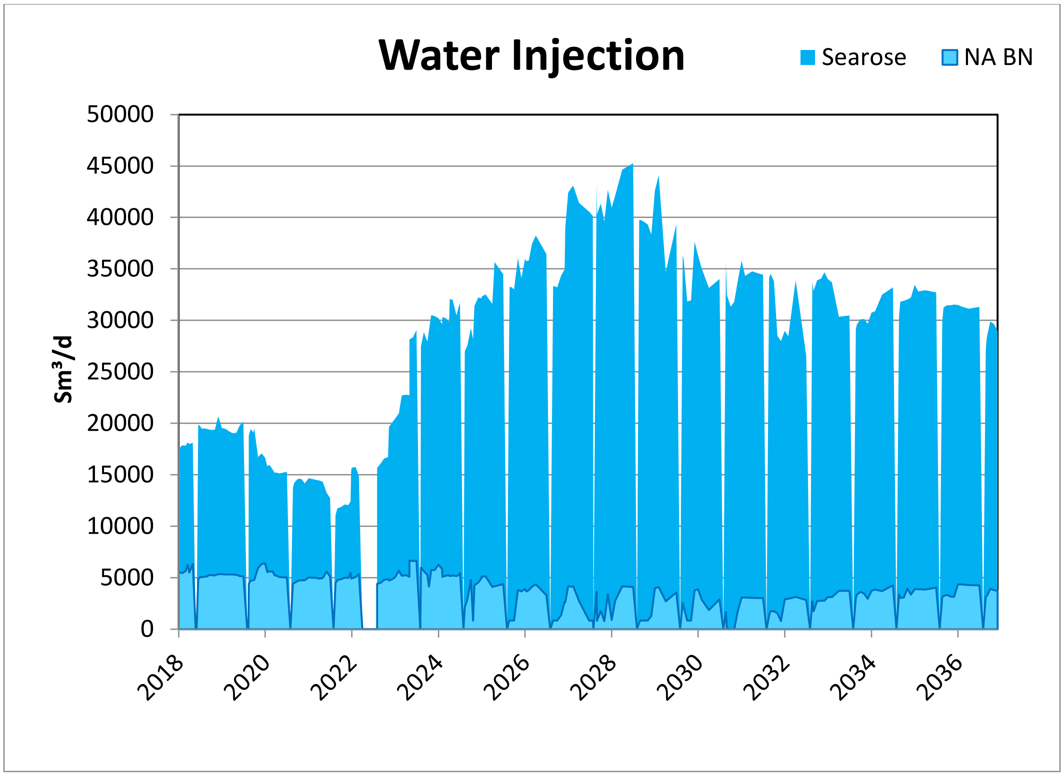

Figure 19: Full-field water injection profile (Husky, 2018).

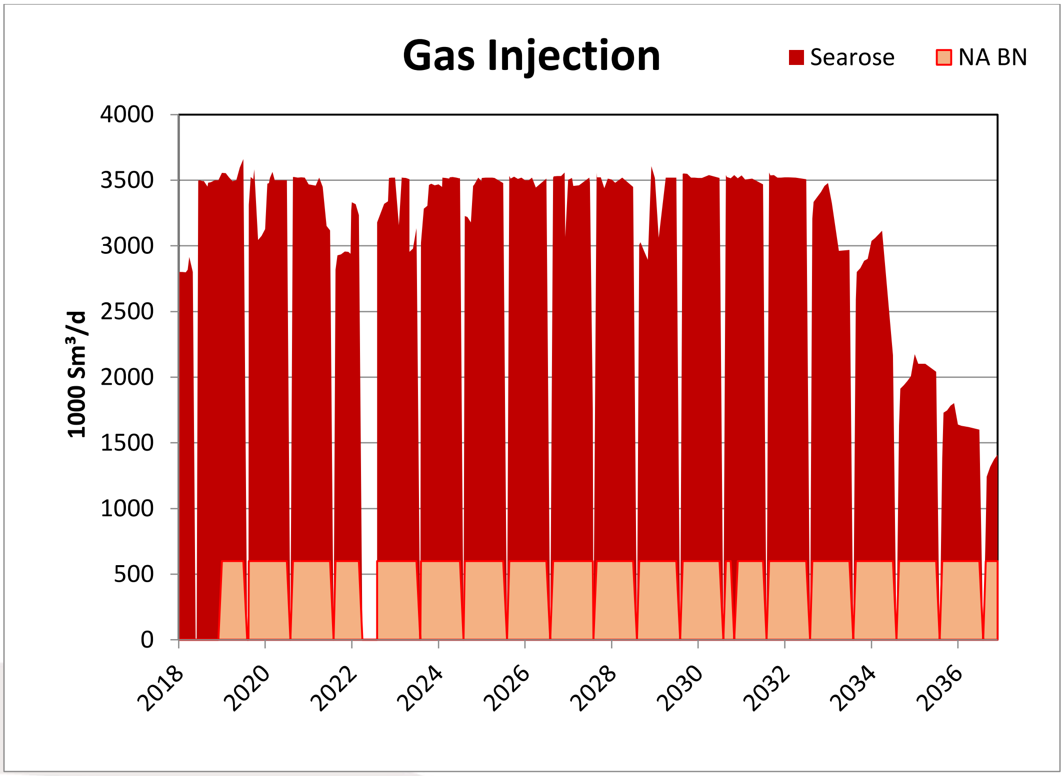

Figure 20: Full-field gas injection profile (Husky, 2018).

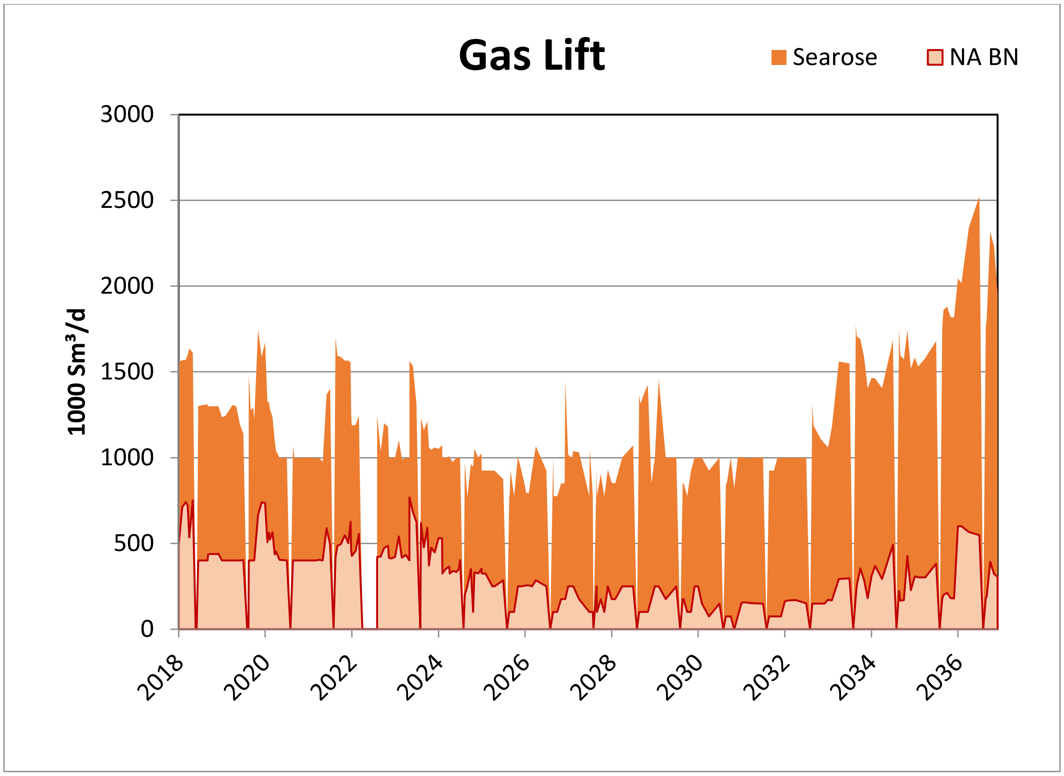

Figure 21: Full-field gas lift profile (Husky, 2018).

Staff reviewed the full-field profiles to determine if there was any cause for concern regarding the *SeaRose FPSO* facility handling capabilities. Considering the previously listed facility constraints, no significant issues were noted. There is a brief period toward the end of field life where the gas-lift volume exceeds the limits of the facility. Staff raised this to the Proponent and the future constraint was acknowledged. The Proponent has initiated an engineering investigation to evaluate options to increase the facility's gas-lift limit. Early results from this engineering investigation indicate that facility modifications during a future turnaround will allow this constraint to be lifted.

The profiles provided in the Application show production from North Amethyst to the end of 2036. Staff notes however that due to recent performance trends of the North Amethyst BNA producers, the productive life of the pool will likely end before then.

4.5.4. Gas Handling Strategy

All gas produced from White Rose Asset to date, with the exception of flare gas, has been used as fuel gas to power the *SeaRose FPSO*, stored via the Northern Drill Centre (NDC) gas storage wells or injected in the J-05 1 gas injector located in the South White Rose Extension (SWRX) Pool for gas flooding.

Currently, the majority of the produced gas from the *SeaRose FPSO* is injected into the J-05 1 gas flood well, as the NDC gas storage wells have limited gas storage volume remaining. The J-05 1 gas flood is capable of injecting at a maximum rate of approximately 3.5 MMSm^3/d which, as shown in Figure 20, is sufficient to handle the predicted gas injection volumes over the life of the field. However, with continued development in the White Rose area, and GOR progression uncertain, the Proponent sees value in having the ability to gas flood multiple gas caps to provide gas handling flexibility and enable production optimization. Therefore, the Proponent is now proposing to gas flood the North Amethyst BNA Pool as the next step in the White Rose gas handling strategy.

The Proponent expects this strategy to be effective for the near term (2018-2025) development of the greater White Rose Asset prior to the West White Rose Wellhead Platform coming online, but will continue to evaluate other options in the meantime. Several options were identified in the Application for the mid to long term (2025+), including drilling gas-flood or WAG injectors in the South Pool of the White Rose Ben Nevis reservoir from the wellhead platform.

Staff agrees that additional gas handling options will allow for maximum recovery of the White Rose Asset overall. Should the Proponent be unable to handle produced gas volumes, oil production will need to be reduced in order to manage gas flaring. Implementing gas flooding in the North Amethyst BNA Pool will provide the Proponent with flexibility in the event that operational issues limit injection into the J-05 1 gas injector, or if near-term gas production volumes exceed predictions. The Proponent is expected to implement gas flooding or WAG injection in the Northern Terrace and/or Central Block gas caps of the South Pool through the wellhead platform; however, this is not expected until later in the field life. The addition of the North Amethyst BNA Pool gas flood will help bridge the gap from now until these wells come online.

While Staff finds the proposed approach for gas utilization to be acceptable, it should be noted that the proposed plan only covers gas flooding of the North Amethyst BNA Pool while oil production is ongoing. Should oil production cease at some point in the future, further gas injection in the reservoir would then be considered gas storage, which is not addressed in the current Application. The Proponent would be required to apply for a gas storage license at that time before any further gas injection into the BNA Pool would be permitted.

Condition 4: Prior to cessation of oil production from the North Amethyst BNA Pool, the Proponent must update the C-NLOPB on its plans for the pool and any wells no longer being utilized. If continued gas injection is planned, the Proponent will be required to apply for a gas storage licence prior to commencing any gas storage operations.

4.6. Reservoir Simulation

To support this Application, the Proponent submitted an updated reservoir simulation model for the BNA Pool of the North Amethyst Field. Staff did not construct independent geological or reservoir simulation models for the review of the Application. Instead, Staff performed an extensive assessment of the Proponent’s model and the various simulation cases it contained.

A further description of the reservoir simulation models, including grid size, active cell count and other model properties, was included in the Application. The average cell size (in meters) is 50 (i) x 50 (j) x 1.5 (k) and the total number of active cells is 1.95 million. The model includes approximately 25.5 MMm^3 (160 MMbbls) STOOIP. Two GOCs exist in the simulation model, the first at -2,334 m TVDss and second at -2,363 m TVDss, and they are applied over different regions. The model also contains two different

OWCs, one at -2,390 m TVDss and the second at a depth of -2,369 m TVDss, applied for different regions.

Overall, the Proponent's reservoir simulation model and the assumptions used to create it are reasonable and appropriate, and are consistent with modelling constraints used in the past by the Proponent.

4.6.1. Oil Production Results and Forecasts

The BNA Pool simulation model is a history-matched model with oil production up to the end of December 2017 matching the actual production from North Amethyst Field. The Proponent achieved a reasonable history match overall for the model. The Proponent supplied a base-case production forecast as well as forecasts for two gas flood options: conventional gas injector gas flood and gas lift-gas flood.

4.6.2. Base-Case Production Forecast

The base-case production forecast represents the initial phase of development for the BNA Pool. This is comprised of four horizontal oil producers and one multilateral producer which are generally positioned at approximately the mid-point of the oil column. Flood and pressure support were provided by down-dip water injectors – three deviated and one horizontal. Additional IOR initiatives are also included within the base-case production forecast, which consists of two attic oil infill producers, G-25 10 and G-25 11. G-25 10 was brought online in February 2017 and G-25 11, which was forecasted in the simulation model to come online on March 31, 2018 at 1,000 m^3/d oil rate, had an actual start date of March 22, 2018 at 150 m^3/d and 80 percent water cut. The G-25 11 infill well has since been shut in due to increased water cut and lower than expected oil rate attributed to a well completion issue.

In the base-case production forecast, production beyond December 2017 shows a slight increase in production rate due to the G-25 11 infill well coming online, followed by a steep decline in production until 2022, after which the rate stabilizes to a more gradual decline for the remainder of field life, until 2036. The reservoir simulation model indicates total production from the BNA Pool to be 10.2 MMm^3 (64.5 MMbbls). This recoverable volume is represented by the simulation model only, and differs from the Proponent's deterministic reserves estimate of 9.9 MMm^3 (62.2 MMbbls) listed in the Application.

Figure 22 shows the oil production rate and cumulative production from the BNA Pool reservoir simulation model base case.

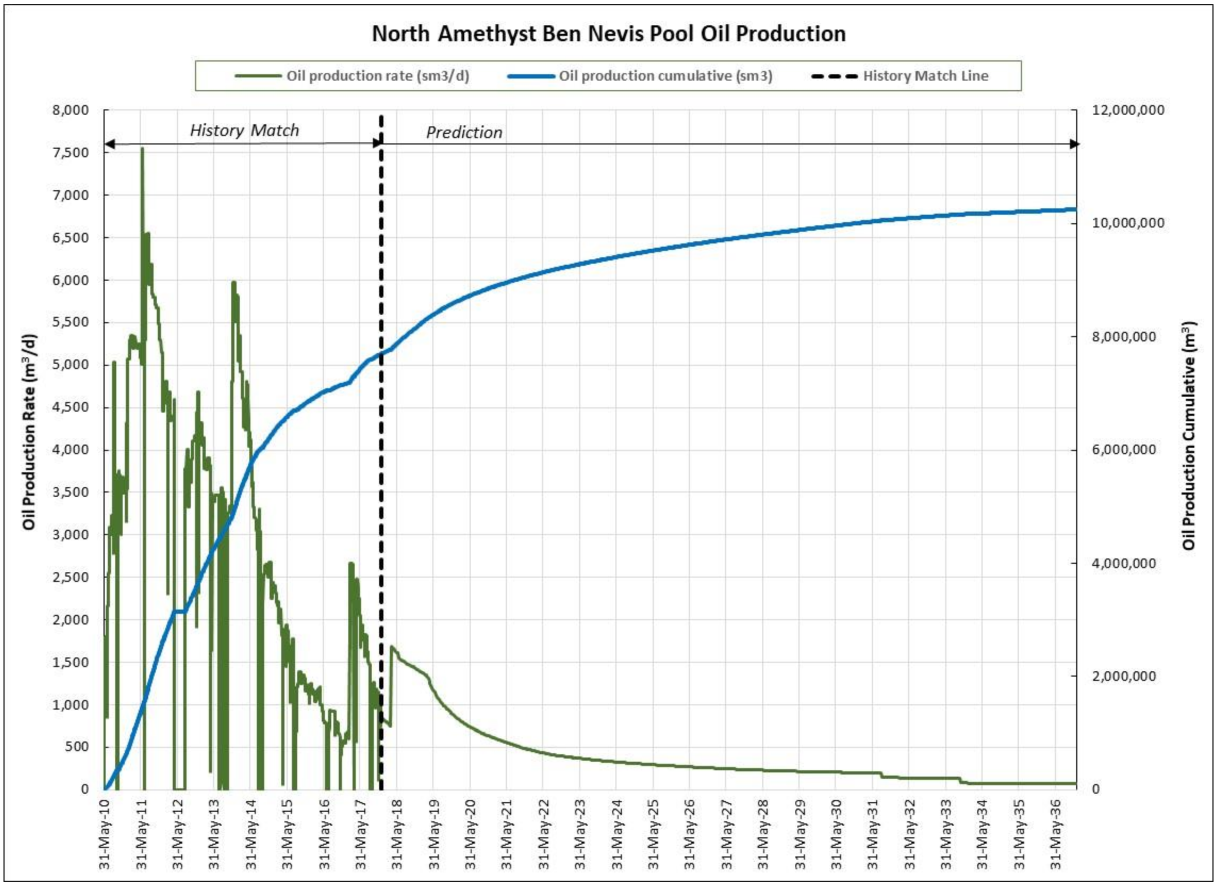

Figure 22: North Amethyst BNA Pool oil production rate and cumulative – Base Case.

4.6.3. Conventional Gas Injector Gas Flood

As indicated previously, this Application considered two options for gas flooding the North Amethyst Field. The first case considered in simulation was the conventional gas injector case. Multiple sensitivities were conducted using a conventional gas injector drilled into the North Amethyst gas cap in the K-15 well region from the SWRX drill centre. These sensitivities had different VRR with varying percentages of gas injection and water injection. These cases include:

- VRR = 1.00 with 30 percent by gas injection and 70 percent by water injection (Simulation Case Name: 30VRR100)
- VRR = 1.00 with 60 percent by gas injection and 40 percent by water injection (Simulation Case Name: 60VRR100)
- VRR = 0.80 with 30 percent by gas injection and 40 percent by water injection (Simulation Case Name: 30VRR80)
- VRR = 1.25 with 30 percent by gas injection and 70 percent by water injection (Simulation Case Name: 30VRR125)
- VRR = 1.25 with 60 percent by gas injection and 40 percent by water injection (Simulation Case Name: 60VRR125)

All cases predict production acceleration and/or incremental oil recovery, as illustrated in Table 5 and Figure 23. The expected incremental recovery from these cases ranges from 0 – 0.67 MMm^3 (0 – 0.42 MMbbls).

Table 5:Expected incremental oil recovery from conventional gas injector gas flood.

	Base Case		VRR 1.25 – 30% GI 70% WI		VRR 1.25 – 60% GI 40% WI		VRR 1.00 – 30% GI 70% WI		VRR 1.00 – 60% GI 40% WI		VRR 0.80 – 30% GI 70% WI	
	MMm^3	MMbbls	MMm^3	MMbbls	MMm^3	MMbbls	MMm^3	MMbbls	MMm^3	MMbbls	MMm^3	MMbbls
EUR	10.2	64.5	10.9	68.7	10.8	67.8	10.7	67.4	10.6	66.9	10.2	64.4
Incremental EUR			0.67	4.2	0.54	3.4	0.47	3.0	0.38	2.4	0.0	0.0
Base Case Forecast												
Forecast with VRR = 1.25 with 30 percent by gas injection and 70 percent by water injection												
Forecast with VRR = 1.25 with 60 percent by gas injection and 40 percent by water injection												
Forecast with VRR = 1.00 with 30 percent by gas injection and 70 percent by water injection												
Forecast with VRR = 1.00 with 60 percent by gas injection and 40 percent by water injection												
Forecast with VRR = 0.80 with 30 percent by gas injection and 70 percent by water injection												

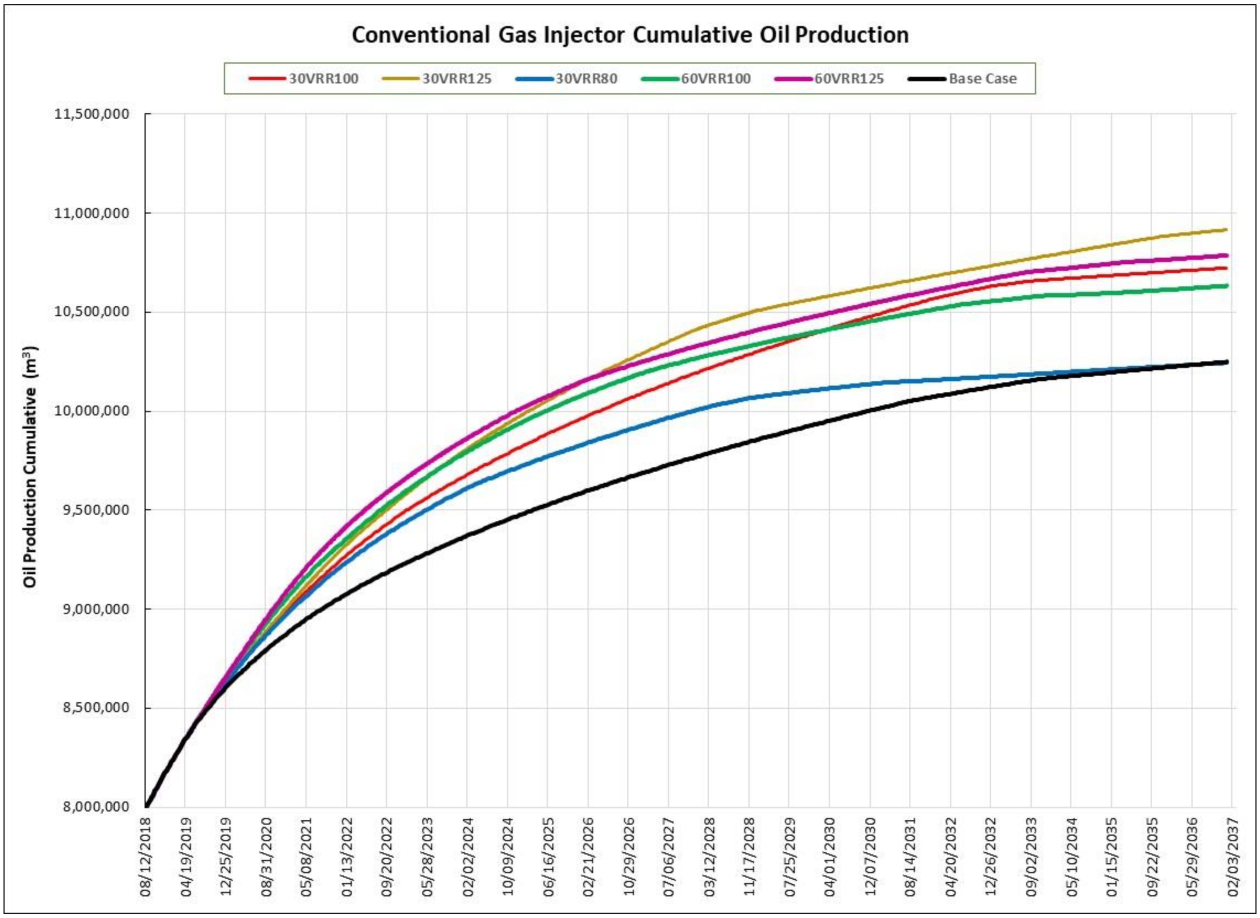

Figure 23: Cumulative oil production from conventional gas injector gas flood cases.

4.6.4. Gas-Lift Gas Flood

The simulation model also explored gas flood through existing North Amethyst producers via gas-lift infrastructure as another option. Sensitivities were conducted using the gas-lift system of the G-25 2 producer to inject gas. While these sensitivities were completed for a single producer, this will not limit the ability to use other producers, provided safety and conservation of resource is maintained. These cases include:

- VRR = 1.00 with 600,000 sm^3/day gas injection (constant) and remaining by water injection (Simulation Case Name: G252GI_600K)
- VRR = 1.00 with 300,000 sm^3/day gas injection (constant) and remaining by water injection (Simulation Case Name: G252GI_300K)
- VRR = 0.75 with 600,000 sm^3/day gas injection (constant) and remaining by water injection (Simulation Case Name: G252GI_VRR075_600K)
- VRR = 1.25 with 30 percent by gas injection and 70 percent by water injection – BHP limit of 240 bar set on G-25 2 (Simulation Case Name: G252GI_30VRR125_BHP240)

As with the previous gas injection sensitivities, all of the cases predict production acceleration and incremental oil recovery via existing infrastructure, as illustrated in Table 6 and Figure 24. The expected incremental recovery from gas lift gas flood is in the range of 0.30 – 0.46 MMm^3 (1.9 – 2.9 MMbbls).

Table 6: Expected incremental oil recovery from gas lift gas flood.

	Base Case		VRR 1.0 – 600K GI		VRR 1.0 – 300K GI		VRR 0.75 – 600K GI		VRR 1.25 – 30% GI 70% WI 240 BHP	
	MMm^3	MMbbls	MMm^3	MMbbls	MMm^3	MMbbls	MMm^3	MMbbls	MMm^3	MMbbls
EUR	10.2	64.5	10.7	67.4	10.6	66.8	10.6	66.6	10.5	66.3
Incremental EUR			0.46	2.9	0.37	2.3	0.34	2.2	0.30	1.9
Base Case Forecast										
Forecast with VRR = 1.00 with 600,000 sm^3/d gas injection (constant) and remaining by water										
Forecast with VRR = 1.00 with 300,000 sm^3/d gas injection (constant) and remaining by water										
Forecast with VRR = 0.75 with 600,000 sm^3/d gas injection (constant) and remaining by water										
Forecast with VRR = 1.25 with 30 percent by gas injection and 70 percent by water injection - BHP										

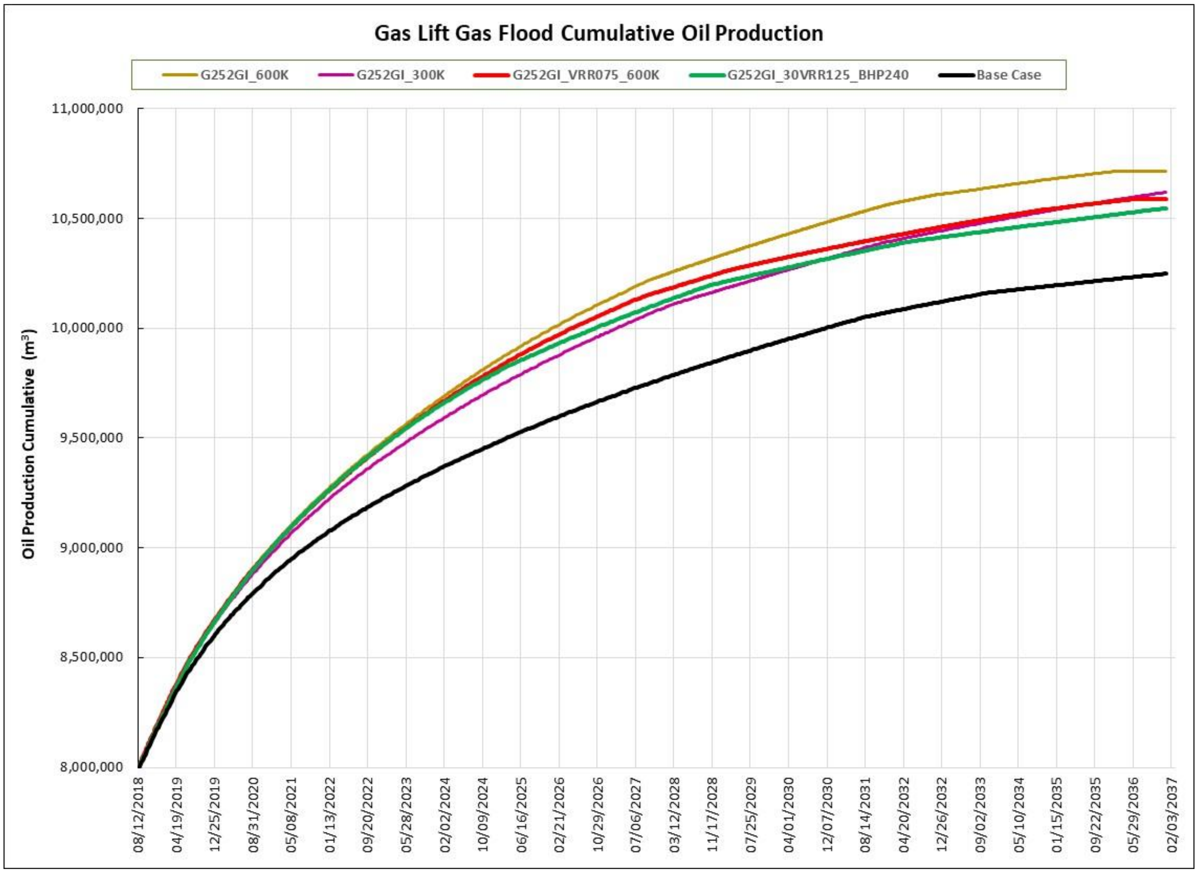

Figure 24: Cumulative oil production from gas lift gas flood cases.

4.6.5. Reservoir Simulation Summary

The Proponent used the available geological and reservoir engineering information to develop a reasonable reservoir simulation model for the BNA Pool. The model and cases submitted provide an adequate overview of the development area. Staff's analysis indicates that the current BNA Pool reservoir simulation model is sufficient in the context of this Application.

Due to the time and cost to drill a dedicated gas injector, the Proponent has indicated that gas flooding through existing North Amethyst oil producers via the existing gas-lift infrastructure is the most likely scenario to be implemented initially. It is also expected that the G-25 2 oil producer, which has reached its economic limit due to high water cut, will be the first well utilized. This is consistent with the simulation model.

The Proponent's simulation model shows production continuing until 2036. However, due to recent performance trends, Staff notes that the productive life of many of the current oil producers will likely end before that date.

4.7. Reserves Estimates

The Application presented the Proponent's probabilistic recoverable estimates for the BNA Pool. Reservoir quality characteristics specific to the pool and well performance data were utilized to generate these estimates.

The Proponent also provided a most likely deterministic recoverable estimate of 9.9 MMm^3 (62.2 MMbbls) for the BNA Pool. This recoverable volume was estimated using the reservoir simulation model to forecast incremental oil volumes for the two recent infill producers, in conjunction with decline curve analysis from the mature producers. High and low side deterministic recoverable estimates were not provided in the Application.

As discussed in Section 4.1, Staff did not construct independent geological or reservoir simulation models for the review of the Application. Instead, Staff calculated low, most likely and high side deterministic recoverable estimates using a combination of decline curve analysis techniques, assessment of the Proponent's geological model and the results of the various simulation model cases provided. Staff also considered some of the Proponent's plans for potential well interventions, and the potential utilization of other end-of-life oil producers for gas flooding in the future, when calculating the low, most likely and high side recoverable estimates. A comparison of the Proponent's and Staff's recoverable oil estimates are presented in Table 7.

Table 7: Recoverable oil volumes estimates.

Probabilistic Estimates	**P90**		**P50**		**P10**	
	MMm^3	**MMbbls**	**MMm^3**	**MMbbls**	**MMm^3**	**MMbbls**
Husky	**7.6**	**47.6**	**9.9**	**62.8**	**12.5**	**78.5**
Deterministic Estimates	**Low**		**Mid**		**High**	
	MMm^3	**MMbbls**	**MMm^3**	**MMbbls**	**MMm^3**	**MMbbls**
Husky	**-**	**-**	**9.9**	**62.2**	**-**	**-**
C-NLOPB	**8.6**	**53.9**	**9.1**	**57.5**	**10.2**	**64.4**

Staff's most likely recoverable estimate of 9.14 MMm^3 (57.5 MMbbls) is lower than both the Proponent's deterministic and probabilistic estimates; however, the Proponent's estimates were completed before drilling the G-25 11 infill producer. Incorporating post-drill results from this well would likely result in Staff's and the Proponent's recoverable oil estimates being closer.

It should be noted that Staff's most likely EUR of 9.14 MMm^3 (57.5 MMbbls) is a decrease of 1.66 MMm^3 (10.4 MMbbls) from the previous estimate of 10.8 MMm^3 (67.9 MMbbls) at the time of North Amethyst Development Plan approval (Decision 2008.03). The assessments prepared by the C-NLOPB and the Proponent were aligned at the time, but were based on results from a single well; the K-15 discovery well was the only North Amethyst well drilled at that point. Since then, as discussed in Section 4.3, further delineation and development drilling have resulted in a decrease in the estimated oil in place. It is worth noting that, although the oil-in-place and recoverable estimates have decreased, the estimated recovery factors have increased due to increased well count compared to the original plan. The initial depletion plan included only four oil producers in the BNA Pool. Currently, there are seven oil producers including one multilateral well.

To date, 7.86 MMm^3(49.5 MMbbls) of oil have been produced from the BNA Pool. Taking Staff's updated most likely recoverable oil estimate into account, the expected remaining oil to be produced is 1.28 MMm^3 (8.0 MMbbls).

4.8. Conclusion and Recommendation

In the Staff Analysis for the North Amethyst Development Plan (Decision 2008.03), Staff identified that the proposed depletion strategy using water flood only could potentially result in a significant volume of attic oil being trapped between the oil producers and the GOC. While Staff concurred with the Proponent's original plan, it was noted that the Proponent would be required to examine options to exploit this attic oil prior to termination of oil production.

Following execution of the initial phase, the Proponent identified IOR opportunities up dip of the current oil producers. Infill oil producers G-25 10 and G-25 11 were drilled in the north and south regions of the BNA Pool to target the attic oil. To further improve recovery of attic oil, the current Application proposes implementation of gas flooding in the BNA Pool. Staff agrees that gas flooding has the potential to sweep attic oil to the existing producers and increase overall recovery of the BNA Pool.

Although Staff did not build independent geological and reservoir simulation models, the Proponent's models were assessed and Staff found the methodology and approach used to be reasonable. These models indicated that gas flooding was not a detriment to oil recovery and in each scenario, the predicted oil recovery was increased or accelerated. The simulation model indicated that the incremental recoverable oil from implementing gas flooding is in the range of 0 – 0.7 MMm^3 (0 – 4.2 MMbbls) for a dedicated gas injector and 0.27 – 0.46 MMm^3 (1.7 – 2.9 MMbbls) for the case of gas injection through the gas lift system in an existing end-of-life oil producer.

Based on these incremental volumes, and performance trends of the existing oil producers, Staff conducted an assessment of EUR for the BNA Pool. As a result, Staff now expects a most likely EUR of 9.14 MMm^3 (57.5 MMbbls). This estimate is a decrease from Staff's previous assessment of 10.8 MMm^3 (67.9 MMbbls) at the time of North Amethyst Development Plan approval (Decision 2008.03). At that time, only the K-15 discovery well had been drilled. Since then, further delineation and development drilling have resulted in a decrease of the estimated oil in place, and consequently, a decreased recoverable estimate.

These incremental production volumes were also assessed against facility capacities and Staff has not identified any negative impact from the incremental volumes. Gas handling capacity has been the main limiting factor on the FPSO; however, the Proponent recently made some facility upgrades that have increased the capacity of the gas compression system. The Proponent expects that these changes will better position the facility for future developments.

In addition, the ability to inject gas in the BNA Pool will help to alleviate gas handling constraints. Having the ability to inject gas in the BNA Pool gives the option to gas flood multiple gas caps, providing gas handling flexibility and enabling production optimization. Staff notes that should oil production cease from the BNA Pool, the Proponent must apply for and be granted a gas storage licence in order for gas injection operations to continue.

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

Condition 1: With the exception of G-25 2, should any other oil producer be used for gas flooding operations, a change in well designation will have to be approved by the Chief Conservation Officer (CCO) prior to any gas injection operations being allowed to occur.

Condition 2: That prior to initiating a water-alternating-gas (WAG) scheme in the North Amethyst BNA Pool, 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: The Proponent must provide an update on the impacts of removing the Voidage Replacement Ratio (VRR) target of 1.0 to 1.2 from the North Amethyst reservoir management plan in the update to the Resource Management Plan in the North Amethyst Annual Production Report each year. Should the Chief Conservation Officer (CCO) determine at any time that the removal of the VRR target is detrimental to oil recovery the Proponent will be required to revert to a VRR target of 1.0 to 1.2.

Condition 4: Prior to cessation of oil production from the North Amethyst BNA Pool, the Proponent must update the C-NLOPB on its plans for the pool and any wells no longer being utilized. If continued gas injection is planned, the Proponent will be required to apply for a gas storage licence prior to commencing any gas storage operations.

5. 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.

5.1. Well Operations

The addition of gas flood as a means of secondary recovery is not a new concept for the jurisdiction nor the Proponent; however, it is new to the North Amethyst Field. The Proponent is proposing a base case gas flood strategy consisting of two options, both of which may or may not be implemented. These two options are:

1) Drilling conventional gas injection wells into the gas cap of the BNA Pool from the SWRX drill center; and,
2) Conducting gas flood through existing producers via gas lift infrastructure.

The plan of drilling and completing gas injection wells, conceptually, is consistent with the currently approved Development Plan strategy for the White Rose Field for both gas storage and pressure maintenance. The Proponent has confirmed that any new gas injection well planned to be drilled into the North Amethyst Field from the SWRX drill center will be aligned with the design criteria for conventional gas injection wells, as approved in the Decision 2013.04. The specifics of each individual well design will be reviewed and assessed as part of the Approval to Drill a Well (ADW) process. The

Proponent has also confirmed that there will be no infrastructure-related modifications required to the *SeaRose FPSO* as a result of initiation of conventional gas injection or gas flood into the BNA Pool.

The concept of converting existing gas lifted production wells to gas injection wells is new for the Canada - Newfoundland and Labrador Offshore Area. Based on this, the Proponent will need to ensure that its application for Operations Authorization addresses the following aspects, in addition to all other regulatory requirements pertaining to the authorization and approval process:

- A change in intended service for an existing well will require that the Proponent develop a stringent condition monitoring plan for tree valves and various completion components to ensure components are not damaged, that they will maintain reliability due to gas injection operations and that the integrity of well barrier envelopes will be maintained through the remaining life of the well.
- Confirmation that all management of change processes internally to the Proponent's management system must be completed and signed off by the appropriate personnel.
- The Certifying Authority must acknowledge that, within its scope of verification activities, it is satisfied with the change in service for the well.

Note that well specific details associated with the change in service will have to be satisfactorily outlined in supporting documentation that demonstrates compliance with the regulations and with good industry practice. The Proponent must seek C-NLOPB acknowledgement prior to conducting any operations related to the proposed change in service.

In addition to the two base case options noted above, the Proponent has also highlighted two optional gas flood methods that are under evaluation for potential future application, and therefore are included in this Development Plan Amendment. WAG flood via the *SeaRose FPSO* and/or WAG flood via the future West White Rose Wellhead Platform are currently being evaluated as options for gas flood in the BNA Pool at North Amethyst Field. Unlike the options under the base gas flood strategy for North Amethyst, these concepts may require adjustments to existing subsea infrastructure, and in the case of WAG flood from the *SeaRose FPSO*, this will also mean implementing control system modifications. The Proponent has confirmed that such changes to the control system would also require procedural updates and training for FPSO staff. As noted in the Application, further evaluation is required to determine the extent of these modifications; however, if the Proponent decides to proceed with such changes, then these will be assessed as part of the Operations Authorization (OA) processes.

As the Proponent better defines its plans related to gas flood or WAG, engagement with the C-NLOPB will be required to ensure alignment with the Development Plan Amendment.

5.2. Certification

Based on the scope identified for the base case gas flood strategy, the Proponent has confirmed that Certifying Authority (CA) services will include activities during the design, fabrication, installation and commission of all subsea equipment. Approval will also be required from the CA for converting producers to gas injectors, as the intended well service will have changed. If WAG is implemented, the CA will also assess any modifications to the existing topsides systems.

All work outlined as part of the Application is consistent and captured under the currently approved Scope of Work for the *SeaRose FPSO* and White Rose Asset (inclusive of North Amethyst).

5.3. Conclusion and Recommendation

Activities in connection with this Application will be managed in accordance with established processes, procedures, and applicable well approvals. Based on this operation staff recommend approval of this Application.

6. Safety

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

In the case of the Application, the impacts on personnel safety will remain consistent with current operations and will have no direct impact with the proposed changes to the Development Plan. The Proponent has confirmed that there will be no infrastructure-related modifications made to the *SeaRose FPSO*; however, if WAG flood is implemented, such changes could result in modifications to the control system which would require procedural updates and training for FPSO staff.

The Proponent will ensure that the existing systems and processes for determining risk continue to go through the appropriate management of change and risk management process.

6.1. Conclusion and Recommendation

No safety concerns were identified that would preclude Staff from recommending approval of the Application. Activities in connection with this Application can be managed in accordance with established processes and procedures.

7. Protection of the Environment

Staff reviewed the Application to determine whether it raises any new environmental issues. This review was conducted in the context of previously completed environmental assessments and C-NLOPB Decision Reports.

The North Amethyst Satellite Development was not contemplated in the Comprehensive Study completed for the White Rose Development (released by the federal Minister of Environment on June 11, 2001). Delineation/Exploration drilling at North Amethyst was assessed as part of the CEAA screening level assessment completed for the *Husky Delineation/Exploration Drilling Program for Jeanne d'Arc Basin Area* (released August 18, 2005). Production operations at the North Amethyst Drill Centre were contemplated in the CEAA Screening level assessment *Husky White Rose Development Project: New Drill Centre Construction and Operations Program Environmental Assessment* (released

April 19, 2007). This work included excavation of an excavated drill centre (EDC), installation of subsea infrastructure and tie-back to the *SeaRose FPSO*. An extension of temporal scope to 2020 was assessed in 2016.

Likewise, the North Amethyst Satellite Development was not contemplated in C-NLOPB Decision 2001.01 which approved the White Rose development, and, although the North Amethyst Field had been identified when Husky applied for the South White Rose Extension Development Plan Amendment, it was not contemplated as part of C-NLOPB Decision 2007.02. The Development Plan for the North Amethyst Field was approved in Decision Report 2008.03.

The additional development activities described in the Application - gas injection – do not represent a functional change in operations at the North Amethyst Drill Centre and, as such, are within the scope of the project assessed in the *Husky White Rose Development Project: New Drill Centre Construction and Operations Program Environmental Assessment*, and the *Husky White Rose Development Project: New Drill Centre Construction and Operations Program Environmental Assessment Addendum*. These activities will not require modification of the existing environmental compliance monitoring or environmental protection plans for production and drilling operations. As such, the proposed activity does not require additional environmental assessment pursuant to the *Canadian Environmental Assessment Act*, and no additional environmentally related conditions need be attached.

7.1. Conclusion and Recommendation

No environmental concerns were identified which would preclude Staff from recommending approval of the Application.