Karish and Tanin Lease Development Plan

Addendum: Karish North Field Development

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1 Introduction and overview

This document forms an addendum to the Karish and Tanin Lease, Field Development Plan (KT FDP) that was submitted to and approved by the Israeli government in 2017. The Management Summary of this KT FDP was subsequently updated and approved in 2018 following a Final Investment Decision on the elements associated with the development of the Karish Main field. At this time, it was noted, that approval to drill an exploration well on the Karish North prospect (described in the KT FDP) had been received. This well was subsequently drilled in March/April 2019 resulting in a discovery of gas and associated hydrocarbon liquids – oil and condensate. The discovery was appraised in October 2019. Together with a third revision of the KT FDP, this addendum forms a Field Development Plan for the Karish North field.

The addendum has been structured identically to the main KT FDP. General information in the main document that is relevant to the evaluation of the Karish North discovery is referenced but not repeated. Sections that are not relevant for the evaluation of Karish North are retained but left blank.

The Karish North prospect was first identified by Noble but not drilled prior to their relinquishment of the Karish and Tanin discoveries. At this time, Karish North was mapped as a small fault bounded anticline on the downthrown side of the main NE-SW bounding fault of the Karish Main discovery. A separate, smaller faulted anti-cline (Karish North East) was also recognised. The two structures were considered contiguous. Both structures were associated with strong amplitude anomalies that conformed to structure and were of a similar nature to the tuning event demonstrated to be coincident with the Karish Main GWC. Given the close proximity to Karish Main, the simple structure and strong DHI a low risk was assigned to Karish North making it an ideal location for Energean's first exploration well in Israel.

Following Energean's evaluation of the available 3D seismic – including reprocessing – a third exploration prospect was identified in the north Karish area. Karish East was mapped as a faulted 4-way dip structure located on the north side of the NW-SE bounding fault of the Karish Main field. Its western edge was contiguous with the eastern edge of the North/North East prospect separated by an extension of the Karish Main NE-SW boundary fault. In the area between Karish North and Karish East this main fault "scissors" with a section showing no throw over a significant distance. A detailed fault seal analysis indicated that given the high NTG sands in the C reservoir that this fault should not seal against migration of gas between Karish North and Karish East. Whilst all evidence pointed to the three northern structures being part of an overall multi-crested 4 way dip closure (bounded to the south by a fault) it was decided to continue to carry the eastern segment as a separate prospect due to the lack of a convincing DHI in this area.

The initial Karish North exploration well was drilled vertically, slightly off the mapped northern crest. It found gas bearing pay in the B and C units of the Tamar sequence. Reservoir properties of both units were almost identical to those seen in the K1 exploration well. Fluid samples were recovered and showed that Karish North was filled by a richer fluid than found in Karish Main. The calculated CGR at the KN crest exceeds 35 bbls/mmscf increasing to above 80 immediately above the GWC. In Karish Main the equivalent range is 15 to 40. As prognosed pre-drill, the fluid CGR appears to have a strong depth relationship likely indicating the liquid is originating from a lower unit. This initial well was positioned to target the expected GWC in the D sand. Unfortunately, the D sand was found to be pressure disconnected from the C sand and was wet at the location of the exploration probe. A GDT was identified at base C. A gas and liquid charged thin sand in the CD shale was also identified.

The exploration well was sidetracked slightly down dip – around a stuck logging tool – and then drilled on to base Miocene. Although a deeper sand of good quality was identified immediately above TD this was water wet. This short step out increased the GDT by a few additional meters giving confidence that the GWC was, as expected, coincident with the mapped DHI. This however could not be proven with the available data.

A full suite of data was collected from the initial well, and its sidetrack, including logs, a 27m core, samples, pressures and a number of mini-DST production tests including one that was located between two of the B unit sands where no logged pay was apparent. All tests produced gas and demonstrated good permeability.

In October 2019, an appraisal sidetrack was drilled from the exploration well, some 700m to its north. The objectives of this activity was to drill through a GWC within the C reservoir unit, show that this corresponded to the mapped DHI and demonstrate that the north and north-east accumulations were contiguous. All of these objectives were met. A GWC at 4791m was demonstrated from LWD pressures. The D sand aquifer pressure was found to be approximately 30psi greater than in the C sand, which in turn was some 55 psi higher than the aquifer pressure at Karish Main. This difference in pressure further confirms the sealing nature of the deep-seated NE-SW bounding fault with the sands likely connecting only at substantial depth around its tips. Salinity of the water in the northern aquifer must be slightly lower than in the southern aquifer. No separation between the north and north-eastern gas pools was apparent.

Post drilling, data collection and analysis (sonic logs and VSP's) the geophysical model (velocity relationship) was updated and corrected to match the well tops with seismic. Subsequently the amplitude analysis over Karish East was revisited and a weak DHI identified that was conformable to structure and in line with a contact at 4823m in the eastern slope area. This area "sees" the southern – lower pressure – aquifer and hence has a slightly deeper contact, if as expected it contains the same rich gas as sampled in the north. On this basis, it was concluded by D&M (Karish North reserves auditor) that there was greater than 50% probability that the eastern and northern structures are in communication and hence Contingent Resources have been calculated and presented over the entire Karish North structure (including the prospect that was earlier referred to as Karish East).

Reservoir studies have demonstrated that a two well development will effectively drain the entire Karish North structure. The exploration/appraisal well will be sidetracked to the northern crest. This will drain the northern crest, western slope and the western part of the graben area. A second well will be added on the eastern crest draining this area, the eastern slope and the eastern part of the graben. A well on the north eastern crest was reviewed to determine whether this was required to recover the enclosed gas. This crest is very flat and given the high chance the field will see a strong aquifer, simulation work showed that a 3rd well was not required: the north east crest will be drained effectively through the other two wells.

Karish North will be tied back to the 4th (spare) slot on the Karish Main manifold as envisaged in the KT FDP. No modifications to the Power FPSO are required but the second 16" sales gas riser will be added at the same time to allow production to exceed 6.5 BCM/yr. Simulation work has demonstrated that KN is able to produce (from the C sand) at rates of between 2 and 3 BCM/yr. The flowline or flowlines connecting a two well KN mini-manifold to the KM manifold will provide this capacity plus suitable turn down to satisfy late life rates when the wells will be recompleted on the B sands. Actual production rates from the KN area will be managed in tandem with production from the KM wells with the objective of best utilising the installed gas capacity, satisfying gas contractual obligations whilst maximising liquid production up to the capacity of the FPSO.

Two license issues have been identified that will need rectification in parallel with review and approval of this Karish North Field Development Plan. These are outlined in the Karish and Tanin Lease Management Summary.

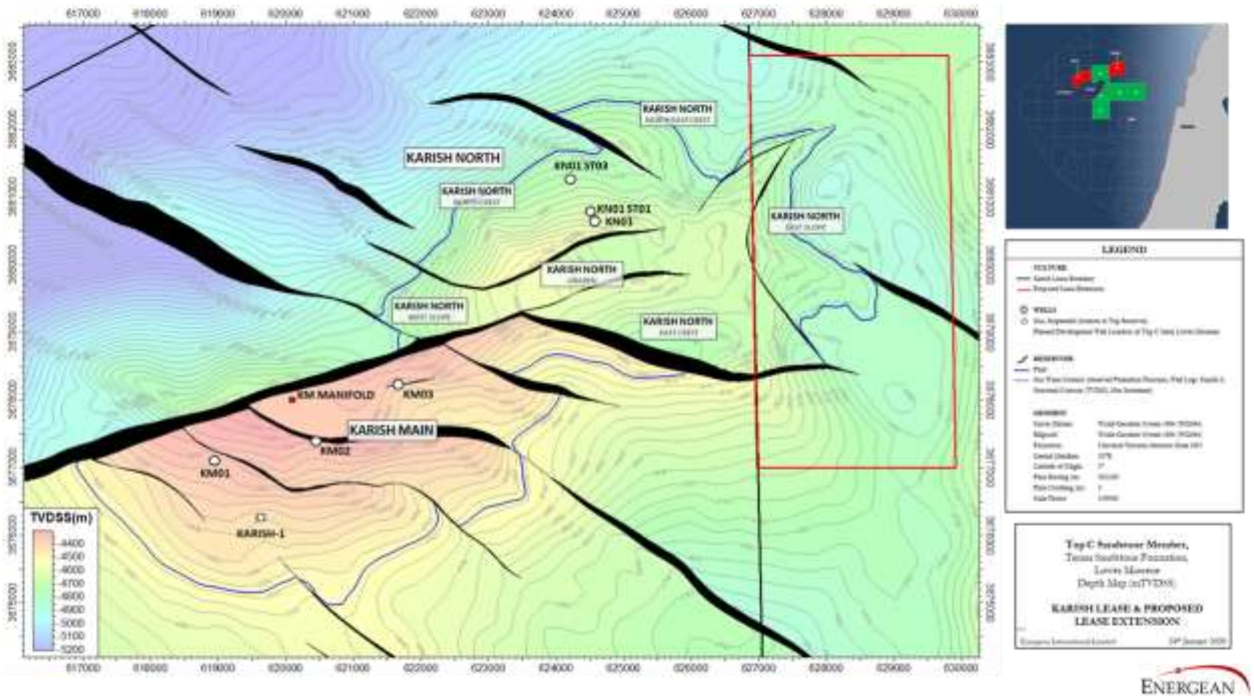


Figure 1-1 – Karish North Top C Map Showing Well Locations

2 Subsurface Geological and Geophysical Evaluation

2.1 Regional Geological Setting

The Karish North discovery is located immediately north of the Karish Main field. Details of the regional geology of the Levantine basin applicable to the evaluation of both Karish North and Karish Main are included in the Karish and Tanin Lease Field Development Plan (KT FDP) that was approved in August 2017.

2.2 Offshore Israel Exploration History

The KT FDP provides comprehensive details of the exploration history of the Levantine basin. No exploration well has been drilled in the Levantine basin – in Israel, Cyprus, Egypt or Lebanon – since this document was prepared and the spudding of the Karish North exploration well in March 2019.

2.3 Karish North Exploration and Appraisal Wells

2.3.1 Karish North 01 Summary

2.3.1.1 Introduction

The Karish North field was discovered in April 2019 via the Karish North 01 (KN01) discovery well which was drilled to penetrate stacked marine basin floor sands identified on seismic which had also been drilled in the Karish Main, Tanin, Tamar and Leviathan wells.

The KN01 well targeted the Karish North field structure. The well was planned with an initial 12 ¼” pilot hole drilled from the 13 5/8” casing shoe directly to the final target sands. Due to low ROP drilling of KN01 was stopped ± 225 m shallower than planned and the decision made to run wireline logs over the open hole. During subsequent 12-1/4" OH wireline logging operations, the MRIL string was temporarily stuck, resulting in a standoff and the MRIL sleeve being left in the hole. KN01 ST01 was drilled in order to deepen the well and achieve all the objectives of the well, including exploring deeper Oliogo-Miocene prospectivity .

KN01 ST02 was drilled as no GWC had been conclusively proven with the discovery well KN01 or its subsequent sidetrack KN01 ST01. Further objectives for ST02 were to confirm that the seismic Direct Hydrocarbon Indicator (DHI) is a robust indicator of a Hydrocarbon Water Contact within the Karish North Upper C Sands and cut a conventional core across the B Sand. The 12 ¼” x 13 ½” hole was drilled from the 13 5/8” casing shoe to the coring point. While pulling out with the coring assembly after attempting to cut the core over the B Sand, the BHA became stuck and was left in hole. After plugging back the second sidetrack, KN01 ST03 was drilled to TD and pore pressure measurements were acquired using the LWD Geotap tool to prove the GWC.

2.3.1.2 Karish North-01 Well Overview.

WELL: KN01			
License No:	I/17	**Field**	Karish North
Operator:	Energean Israel	**Classification**	Exploration
		Geological Target:	Early Miocene - Tamar Sands
Interest:	Energean Israel 100%		
		Surface Co-ordinates:	
Rig:	Stena DrillMax	**Latitude:**	33° 15’ 30.549” N
RTE:	31.6m MSL	**Longitude:**	34° 20’ 14.160” E
		X:	624 560.9m E
Water Depth:	1730.7m MSL	**Y:**	3 680 740.57m N
		TD Co-ordinates:	
Spud Date:	15/03/2019	**Latitude:**	33° 15' 30.236" N
TD Date	08/04/2019	**Longitude:**	34° 20' 13.795" E
		X:	624 551.578m E
Completion Date:	06/11/2019	**Y:**	3 680 730.807m N
Completion Status:	Plugged and Abandoned		
Total Depth (Driller):	4925m MD (-4879.4m TVDSS)	**MWD:**	Halliburton
Total Depth (Logger):	N/A	**Directional Drilling:**	Halliburton
TD Formation	D Sand Member / Tamar Sands Formation	**Mud logging:**	Halliburton
		Wireline Logging:	Halliburton
Max. Well Deviation:	9.68Deg @ 4188.6m MD	**Wireline Witnessing:**	One and Zero
		Coring:	Halliburton
		Biostratigraphy:	PetroStrat
		Wellsite Geology:	D. Timofte / S. Palmer

Table 2-1 – Karish North 01 Well Data

WELL: KN01 ST01			
License No:	I/17	**Field**	Karish North
Operator:	Energean Israel	**Classification**	Exploration
		Geological Target:	Early Miocene - Tamar Sands
Interest:	Energean Israel 100%		
		Surface Co-ordinates:	
Rig:	Stena DrillMax	**Latitude:**	33° 15’ 30.549” N
RTE:	31.6m MSL	**Longitude:**	34° 20’ 14.160” E
		X:	624 560.9m E
Water Depth:	1730.7m MSL	**Y:**	3 680 740.57m N
Kick Off Date:	17/04/2019	**TD Co-ordinates:**	
Kick Off Depth	4239m (4194.9m TVDSS)	**Latitude:**	33° 15' 36.851" N
TD Date	21/04/2019	**Longitude:**	34° 20' 9.581" E
		X:	624 439.918m E
Completion Date:	06/11/2019	**Y:**	3 680 933.166m N
Completion Status:	Plugged and Abandoned		
Total Depth (Driller):	5207m MD (-5121.45m TVDSS)	**MWD:**	Halliburton
Total Depth (Logger):	N/A	**Directional Drilling:**	Halliburton
TD Formation	D Sand Member / Tamar Sands Formation	**Mud logging:**	Halliburton
		Wireline Logging:	Halliburton
Max. Well Deviation:	28.95Deg @ 4827.1 MD	**Wireline Witnessing:**	One and Zero
		Coring:	none
		Biostratigraphy:	none
		Wellsite Geology:	S. Palmer / D. Timofte

Table 2-2 – Karish North 01 ST01 Well Data

WELL: KN01 ST02			
License No:	I/17	**Field**	Karish North
Operator:	Energean Israel	**Classification**	Exploration
		Geological Target:	Early Miocene - Tamar Sands
Interest:	Energean Israel 100%		
		Surface Co-ordinates:	
Rig:	Stena DrillMax	**Latitude:**	33° 15’ 30.549” N
RTE:	31.6m MSL	**Longitude:**	34° 20’ 14.160” E
		X:	624 560.9m E
Water Depth:	1730.7m MSL	**Y:**	3 680 740.57m N
Kick Off Date:	15/10/2019	**TD Co-ordinates:**	
Kick Off Depth	3702m (3662.1m TVDSS)	**Latitude:**	33° 15' 47.311" N
TD Date	19/10/2019	**Longitude:**	34° 20' 2.225" E
		X:	624 245.479m E
Completion Date:	06/11/2019	**Y:**	3 681 252.888m N
Completion Status:	Plugged and Abandoned		
Total Depth (Driller):	4842.5m MD (-4651.6m TVDSS)	**MWD:**	Halliburton
Total Depth (Logger):	N/A	**Directional Drilling:**	Halliburton
TD Formation	B Sand Member / Tamar Sands Formation	**Mud logging:**	Halliburton
		Wireline Logging:	none
Max. Well Deviation:	36.74Deg @ 4270.5 MD	**Wireline Witnessing:**	none
		Coring:	none
		Biostratigraphy:	PetroStrat
		Wellsite Geology:	D. Timofte / R. Iftene

Table 2-3 – Karish North 01 ST02 Well Data

WELL: KN01 ST03			
License No:	I/17	**Field**	Karish North
Operator:	Energean Israel	**Classification**	Exploration
		Geological Target:	Early Miocene - Tamar Sands
Interest:	Energean Israel 100%		
		Surface Co-ordinates:	
Rig:	Stena DrillMax	**Latitude:**	33° 15’ 30.549” N
RTE:	31.6m MSL	**Longitude:**	34° 20’ 14.160” E
		X:	624 560.9m E
Water Depth:	1730.7m MSL	**Y:**	3 680 740.57m N
Kick Off Date:	25/10/2019	**TD Co-ordinates:**	
Kick Off Depth	4002m (3956.2m TVDSS)	**Latitude:**	33° 15' 48.849" N
TD Date	29/10/2019	**Longitude:**	34° 20' 1.488" E
		X:	624 225.802m E
Completion Date:	06/11/2019	**Y:**	3 681 300.009m N
Completion Status:	Plugged and Abandoned		
Total Depth (Driller):	5083m MD (-4886.4m TVDSS)	**MWD:**	Halliburton
Total Depth (Logger):	N/A	**Directional Drilling:**	Halliburton
TD Formation	D Sand Member / Tamar Sands Formation	**Mud logging:**	Halliburton
		Wireline Logging:	none
Max. Well Deviation:	38.01Deg @ 4213.5 MD	**Wireline Witnessing:**	none
		Coring:	none
		Biostratigraphy:	none
		Wellsite Geology:	D. Timofte / R. Iftene

Table 2-4 – Karish North 01 ST03 Well Data

2.3.1.3 KN01 Operational Description.

2.3.1.3.1 36” Conductor Casing Jetting x 24” Hole Section Drilling (1762.3m – 2789.0m MD/-1730.7m – -2753.9m TVDSS

The KN01 well was spudded at 21:45hrs, 15th March 2019. The 24” bit / assembly were made up to the 36” Conductor and the DAT tool. Tagged the seabed at 1762.3m and jetted the conductor to 1833m.

After releasing the DAT tool, the drilling of the 24” section commenced, sliding regularly for directional control, circulating with Sea Water and pumping 100bbl hi-vis pill mid stand. While drilling 20klbs drag was noticed at 2064m, bit bouncing and moderate stick and slip were observed from 2154m to 2325m. From 2315m the MWD tool was unable to decode continuously the toolface orientation during sliding intervals. From 2,428 to 2,665m multiple slide intervals were drilled to maintain verticality (the formation responded with an increased building tendency to higher WOB). At 2665m switched to 10.5ppg Salt Saturated WBM for salt inhibition and completely lost MWD detection to the end of the section (no more directional control). TD of the 24” hole section was called at 2789m.

While tripping out of the hole few tight spots were seen (20klbs overpull) until 2150m. At 2150m 40klbs overpull was observed, made up TDS and washed / backreamed to 1944m. Pulled the 24" drilling BHA to surface.

2.3.1.3.2 20” Casing

The 20" casing was ran in hole on 6.5/8" landing string to 2784.3m and cemented to the mudline with 2474bbls of 12.5ppg Class G lead slurry followed by 802.5bbls of 15.8ppg Class G tail slurry.

2.3.1.3.3 17 ½” Hole Section (2789.0m – 3656.0m MD/2753.9m – 3616.2m TVDSS)

The BOP was run on the marine riser and latched to the KN01 wellhead. The 17 ½” PDC bit was picked up / made up to the mud motor (1.2deg bent) and LWD string (Directional-EWR-DGR-PWD) and run in hole to 2742m. Washed down from 2742m to 2782m (TOC). Drilled out cement, shoe track, cleaned out rat hole and drilled three meters of new formation to 2792 while displacing the hole to 11.5ppg Salt Saturated WBM. Circulated to condition the mud prior to conduct the 11.9ppg FIT. Directionally drilled 17 ½” hole section to 2942 where a 5bbls gain was observed. Performed flow check, well found static. Resumed drilling and reached 3656m (TD of the section) without further incidents. Circulated well clean and performed flow check, well found static. While pulling out the hole condition was generally good with few tight spots observed at 3601m, 3420m, 3302m and 3252m respectively (all wiped clean with 1-3 passes).

2.3.1.3.4 13 5/8” Casing

Ran in hole with the 13 5/8” casing on 6 5/8” drill pipe to 3636m. Washed down from 3636m to 3651.1m (shoe depth) and landed off the hanger. Cemented the 13 5/8” casing with 568bbls of 13.0ppg Class G lead slurry followed by 100bbls of 15.8ppg Class G tail slurry. Theoretical top of cement at 2484m.

2.3.1.3.5 12 ¼” Hole Section (3656.0m – 4925.0m MD/3616.2m – 4879.4m TVDSS

2.3.1.3.5.1 Bit run #1 (3656m to 3659m MD)

The 12 ¼” PDC bit was picked up / made up to the mud motor (1.15deg bent) and LWD string (Directional-EWR-DGR-PWD-ALD-CTN) and run in hole to 3580m. Washed down from 3580m to 3620m (TOC). Drilled out cement, shoe track, cleaned out rat hole and drilled three meters of new formation to 3659m while displacing the hole to 11.6ppg Salt Saturated WBM/KCl/Glycol mud. Circulated to condition the mud prior to conduct 12.5ppg FIT. After the FIT was performed communication with downhole MWD tools could not be established, as a result the BHA was pulled out of hole.

2.3.1.3.5.2 Bit run #2 (3659m to 4710m MD)

Following the tool failure from the previous BHA run, a new 12 ¼” bit, was made up to the same mud motor, new directional and resistivity modules were picked-up and made up to the LWD tools (Directional-EWR-DGR-PWD-ALD-CTN). Ran in hole to 3635m and washed down to the bottom at 3659m. Directionally drilled to 3763m where some difficulties in maintaining tool face control where encountered, also the stabilisers were probably started to hang-up over the slid intervals. Drilling continued in this manner to 3837m, with occasional overpulls in excess of 30klbs to break over. Drilling progressed to 4710m (coring point), by which time the top of the Upper C Sand had been picked, and bottoms-up for geological sample was circulated. With the top of the Upper C confirmed, the 12 ¼” BHA was pulled to surface. Several tight spots were observed on the way out (up to 30klbs), most of which were wiped with 1 pass.

2.3.1.3.5.3 Core run #1 (4710m to 4737m MD)

While drilling at 4000m, in preparation for coring operation, the mud system was treated with 60ml of Tritiated Water. Mud samples were collected before and after coring operations and sent to the core lab. The 12 ¼" coring assembly was picked-up (27m long core barrel) and ran in hole to 4627m. Washed down to the coring point at 4710m. Successfully cored from 4710m to 4737m. Pulled with the 12 ¼" coring assembly to 3619m (inside 13 5/8" casing), performed flow check (well found static) and pulled to 3207m. From 3207m to surface the drill string was pulled at restricted speed (2min/std), in order to account for the core expansion. Core recovery was good, 99.6% (26.9m out of 27m cut).

2.3.1.3.5.4 Bit run #3 (4737m to 4925m MD – Well TD)

The same 12 ¼" bit and mud motor were made up with new LWD tools (Directional-EWR-DGR-PWD-ALD-CTN) then ran in hole to 4760m. Washed down to bottom at 4,737m while logging down the cored section with LWD tools. Drilled 12 ¼" hole section to 4776m where a drilling break (from 15m/hr to 40m/hr) was observed, performed flow check, well found static. Drilling continued to 4811m where another drilling break was seen (from 6m/hr to 28m/hr), at the flow check the well was static. Resumed drilling continued to 4901m where another drilling break was seen (from 4m/hr to 14m/hr), at the flow check the well was found to be static. Resuming drilling, very low penetration rates (0-4m/hr) were recorded and meaningful progress proved to be difficult. At 4,925m decision to stop drilling was made. The well was circulated clean and the 12 ¼" BHA pulled to surface. Few tight spots (30-40klbs) were encountered on the way out, wiped clean with one pass.

2.3.1.3.6 12 ¼" Open Hole Section Wireline Logging Operations

Four wireline logging runs were conducted. In general, good quality data was acquired during wireline logging operations.

Wireline run #1a **GR-XRMI-AST** went without problems to 4912m, logged the main pass from 4898m to 3653m, the repeat pass and pulled out.

Wireline run #1b **GR-MSFL-ALAT-SP-SDLT-DSNT-CSNG** went without problems to 4905m, logged the repeat pass, the main pass from 4901m to 3653m and pulled out.

Wireline run #1c **GR-MRIL** logged first the repeat pass from 4750m to 4693m. Went down to 4905m and recorded the main pass from 4893m to 4856m (4867m for the bottom of the tools) where the tools got stuck. Many attempts were made to pull the tools free while increasing the pulling force. Finally it came free when pulling at 75% of its SWL. The tools were damaged while attempting to free, as a result the wireline string was pulled to surface. At surface it was observed that one stand-off, the MRIL sleeve and the rubber ball were left in hole.

Wireline run #1d **RDT** was completed successfully, only minor issues with the tools were seen. However, while acquiring the pressure tests on the downward pass the tools hung up at 4867m (previous stuck depth on run #1C) and the decision was made not to run any deeper. The programme continued with the formation

pressure tests, formation fluid samples collection and mini DST. At the end of the testing programme the tools were pulled out of hole with no problems.
A total of 47 tests were performed, 32 good tests, 11 tight tests, two no seal and another two lost seal. For the formation fluid sampling, one bottle of water and 14 bottles of gas were collected. Four mini DST were also performed.

The wireline logging programme was suspended at this point (no repeat of MRIL, no VSPs) as it had been decided to sidetrack the well.

2.3.1.3.7 Plug back cementing operations (4825m to 4205m)

KN01 was plugged back to 4205m with two cement plugs.

First cement plug was set from 4825m to 4525m and consisted of 144bbls of 16.0ppg Class G cement. Second cement plug covered the interval from 4505m to 4205m and consisted of 144bbls of 16.0ppg Class G cement.

Karish North (KN-1) Well Conceptual Schematic

Rig	Stena DrillMAX	RTE (m)	31.6	Water Depth (m)	1,726

Casing / Liner Details

Size	Wgt (lbs)	Grade	Connection	Drift (in)	Cement Wt/Type Planned TOC	Mud Weight / Type	FIT / LOT (ppg)
36"	552.7	X-80	Leopard SD EF	31.265	Jetted	8.6 SW & Barazan hi-vis sweeps	N/A
	373.9	X-56	Leopard SD EF	31.265			
21" Ext. joint x 20"	21" 263.9	X-65	Swift DW2 HTAR	18.125	12.5ppg G Lead, 15.8 ppg G Tail, Surface	8.6 SW & Barazan hi-vis sweeps. 10.5ppg SSWBM from 2,735m	11.9
	20" 147.0	X-65		18.125			
13.5/8"	88.2	P-110	VAM 21	12.250	13.0 ppg G Lead, 15.8 ppg G Tail, 2749m MDBRT	11.5ppg SSWBM	

Formation	TVDBRT (m)	MDBRT (m)	Inc.	Description	MDBRT (m)	TVDBRT (m)
Seabed	1762			Top HPWHH	1,758.08	1,758.08
				Top LPWHH	1,759.00	1,759.00
			0°	36" Shoe	1,832.95	1,832.95
Top Evaporite (Anhydrite)	2154.00	2154.00		20" Burst Disc	1,880.38	1,880.38
Top Massive Salt (Halite)	2185.00	2185.00				
			8.7°	20" Shoe	2,784.30	2,711.60
				20" TD	2,789.00	2,716.20
ME20	3425.80	3465.00				
			4.4°	13.5/8" Shoe	3,651.10	3,642.90
				17.1/2" TD / Rat-hole	3,656.00	3,647.80
Base Salt	3774.00	3765.70				
Top Tortonian Sands	4110.00	4099.13				
Base Tortonian Sands	4210.00	4197.80		Tagged Top Cement	4,195.00	
Mid Miocene UC	4398.40	4384.80				
A Sand	4515.50	4501.75				
B Sand	4571.10	4557.34				
Upper C Sand	4686.80	4673.01				
Lower C Sand	4737.00	4723.17				
				12.1/4" Core (CP)	4,737.00	4,723.20
CD Shale	4813.00	4799.13				
D Sand	4831.00	4817.11				
D2 Interval	4858.00	4844.10				
D3 Interval	4890.00	4876.07	2.4°	12.1/4" Well TD	4,925.00	4,911.04

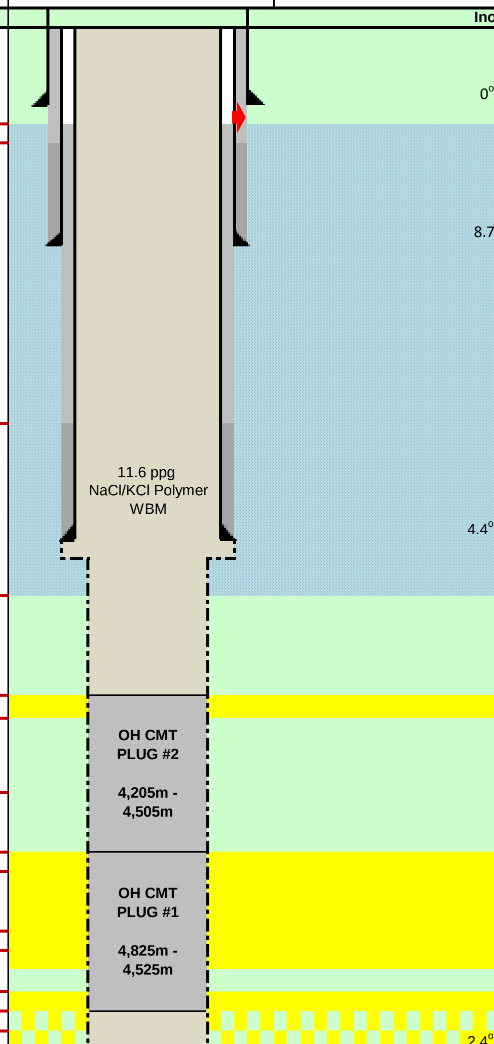


Figure 2-1 - Karish North 01 Well Schematic

2.3.1.4 Karish North 01 ST01 Operational Description.

2.3.1.4.1 12 ¼" Hole Section 4239m – 5207.0m MD/4194.9m – -5121.45m TVDSS

The 12 ¼" bit was made up with Geo-Pilot rotary steerable (RSS) and LWD tool suite (Directional-EWR-DGR-PWD-ALD-CTN). The Geo-Pilot accommodated a near bit gamma ray sensor. The 12 ¼" RSS was run in hole and tagged firm cement at 4195m. The top of the plug was dressed off to 4200m to confirm plug integrity. Kick off was initiated at 4200m and was confirmed with 100% formation returns at 4239m. Drilled 12 ¼" hole section to 4600m where an increase of 5bbls was observed, performed flow check, well found static. From 4774m to 5138m excessive string vibration, stick-slip and shocks were encountered, most probably due to interbedded friable, easy to drill Sandstone with harder Claystone and cemented Sandstone layers. Traces of mechanical cavings were logged briefly at 4829m. Well TD was called at 5207m. While circulating bottoms up, blocky mechanical cavings (2-3cm) were observed across the shakers (10-15% of the cuttings amount). Pulled out to 5164m where 50klbs overpull was recorded. Backreamed to 5155m and pumped out to 5126m. Pulled out to 4350 with numerous 40-50klbs overpulls. Pumped out of hole to 4290m while it became very difficult to come out of hole without rotation. Backreamed / pumped out of hole to 3819m where the standpipe pressure start dropping at 24psi/min. Pulled out of hole wet to 2240m, found 1.5" washout on the 5 ½" drill pipe (2241m from the bit). Pulled the 12 ¼" bit to surface.

2.3.1.4.2 12 ¼" Open Hole Section Wireline Logging Operations

The wireline programme was designed to correlate results from the original KN01 wellbore and to evaluate the D sands to determine pressure support for the reservoir above. Three open hole wireline logging runs were performed

- Run #1a - RDT (for pressure & sample collection)
- Run #1b - VSP (for seismic tie in)
- Run #1c – GR-MRIL (for permeability and porosity measurement)

Wireline run #1a **RDT** was run to 5156m (WL depth) where it hung up and was unable to reach the bottom of the well. A maximum working depth of 5155m (WL depth) was selected for the forward programme. Following the GR log, the wireline depths were adjusted to tie in with the LWD data previously collected for the section.

On the downward pass, the RDT tool string collected 51 pressure tests achieving a total of 29 good tests, 11 failed to achieve an acceptable seal, and 11 were tight. Based on the pre-sample results, a total of 6 fluid sample targets were identified. On the second fluid sample location the tool was kept stationary for 6 hours while attempting to achieve the desired fluid cleanliness, and when attempting to move off station the wireline was found to be stuck (zero cable head tension when performing over pull). The cable was pulled to a maximum of 75% allowable surface tension, coming free with 11klbs over pull. Following the stuck wire event the maximum allowable time on each station was restricted to 2 hours.

Due to the time lost on the first sample and the need to run the VSP in day light hours, (for marine mammal monitoring) the sampling programme was reduced to 5 fluid samples, returning to surface with 1 empty chamber in the RDT tool string.

Wireline run #1b **VSP** acquisition was performed from 5135m to 2055m during daylight hours. The marine mammal observers held watch for 1hr prior to the start in order to confirm it was safe to proceed with logging operations. No problems encountered while acquiring the seismic log.

Wireline run #1c **GR-MRIL** tool string was made up and run in hole to the previously encountered hang up depth at 5159m (WL depth) and depth corrected +6m against master GR log. The first logging pass had to be abandoned at 5100m (WL depth) due to poor amplitude reception from the tool. The tools internal settings were reconfigured, and the tool run back to bottom. The main pass successfully logged while pulling out at 1m/min from 5145 to 4545m. The repeat pass was performed without incident from 4722m to 4605m. The MRIL tool string was pulled out and wireline rigged down.

2.3.1.4.3 KN01_ST01 Plug and Abandon

Ran in hole with 4” drill pipe slotted mule shoe assembly to 5150m without issue. Washed down to 5160m where the string could not pass the obstruction (matching the recorded wireline hang up depth at 5159m). A number of attempts were made to pass the restriction without success by working the string down with 10–15klbs. Circulated out the formation fluid pumped into the wellbore during RDT testing, maximum gas peak at surface 3.7%.

Karish North 01 ST01 was abandoned by setting six cement plugs from 5160m to 3503m. Details of the cement plugs in the table below:

Barrier	Base (m MDRT)	Top (m MDRT)	Verification	Comment
Plug #6	3605	3492	N/A	50bbls 16ppg Class G cement
Plug #5	3847	3,606	TOC tagged at 3606m with 10klbs. Pressure tested to 1700psi.	195bbls 16ppg Class G cement
Plug #4	4187	3867	N/A	155bbls 16ppg Class G cement
Plug #3	4527	4207	N/A	155bbls 16ppg Class G cement
Plug #2	4867	4547	N/A	155bbls 16ppg Class G cement
Plug #1	5160	4887	N/A	129bbls 16ppg Class G cement. Couldn’t pass 5160m with the 4” cement stinger

Table 2-5 – KN01-ST01 Cement Plug Locations

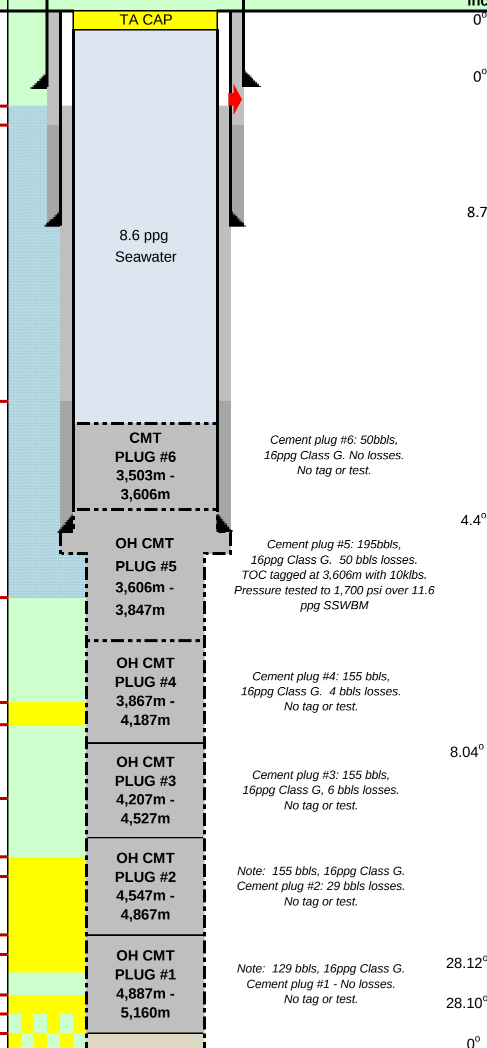
Karish North ST 01 (KN-1 ST 01) Well Conceptual Schematic

Rig	Stena DrillMAX	RTE (m)	31.6	Water Depth (m)	1,726

Casing / Liner Details

Size	Wgt (lbs)	Grade	Connection	Drift (in)	Cement Wt/Type Planned TOC	Mud Weight / Type	FIT / LOT (ppg)
36"	552.7	X-80	Leopard SD EF	31.265	Jetted	8.6 SW & Barazan hi-vis sweeps	N/A
	373.9	X-56	Leopard SD EF	31.265			
21" Ext. joint x 20"	21" 263.9	X-65	Swift DW2 HTAR	18.125	12.5ppg G Lead, 15.8 ppg G Tail, Surface	8.6 SW & Barazan hi-vis sweeps. 10.5ppg SSWBM from 2,735m	11.9
	20" 147.0	X-65		18.125			
13.5/8"	88.2	P-110	VAM 21	12.250	13.0 ppg G Lead, 15.8 ppg G Tail, 2749m MDBRT	11.5ppg SSWBM	12.5

Formation	TVDBRT (m)	MDBRT (m)
Seabed	1762	
Top Evaporite (Anhydrite)	2154.00	2154.00
Top Massive Salt (Halite)	2185.00	2185.00
ME20	3425.80	3465.00
Base Salt	3774.00	3765.70
Top Tortonian Sands	4110.00	4099.13
Base Tortonian Sands	4210.00	4197.80
Mid Miocene UC	4425.10	4380.10
A Sand	4525.50	4479.00
B Sand	4583.70	4535.40
Upper C Sand	4705.00	4649.90
Lower C Sand	4766.00	4703.40
CD Shale	4848.00	4777.40
D Sand	4878.00	4802.90
D2 Interval	4910.50	4833.80
D3 Interval	4938.00	4860.30



Inc.	Description	MDBRT (m)	TVDBRT (m)
0°	Top HPWHH	1,758.08	1,758.08
	Top LPWHH	1,759.00	1,759.00
0°	36" Shoe	1,832.95	1,832.95
	20" Burst Disc	1,880.38	1,880.38
8.7°	20" Shoe	2,784.30	2,711.60
	20" TD	2,789.00	2,716.20
4.4°	13.5/8" Shoe	3,651.10	3,642.90
	17.1/2" TD / Rat-hole	3,656.00	3,647.80
8.04°	Kick off point	4,239.00	4,226.50
28.12°	End of build	4,786.40	4,753.64
28.10°	End of tangent	4,867.90	4,825.24
0°	12.1/4" Well TD	5,207.00	5,153.10

Figure 2-2 - Karish North 01 ST01 Well Schematic

2.3.1.5 Karish North 01 ST02 Operational Description

2.3.1.5.1 12 ¼” x 13 ½” Hole Section Drilling 3702.0m – 4842.5m MD/3662.1m – 4651.6m TVDSS

The rig returned to KN01 location after drilling three wells in the Karish Main field. After completing BOP testing 12 ¼” PDC Bit was picked up and made up with 8” iCruise RSS, LWD string (ABG-Directional-EWR-DGR-PWD) and 13 ½” XR Underreamer and ran in hole to 3424m. Washed down from 3424m to 3492m (TOC) and drilled out cement to 3680m. Initiated 12 ¼” sidetrack at 3680m and confirmed well sidetracked at 3702m (Kick off Point). Drilled 12 ¼” hole section to 3830m (60m below base of salt) and opened 13 ½” XR Underreamer. Opened 12 ¼” hole to 13 ½” from 3769m. Directionally drilled 12 ¼” x 13 ½” hole section to 3905m. Controlled the ROP to 15 m/hr from 3905m to 4174m due to dropping tendency of the BHA. Experienced high torque with severe stick slip and lateral vibration with string stall out tendency through the base of Tortonian sandstone from 4174m to 4233m. Directionally drilled 12 ¼” x 13 ½” hole section from 4233to 4543m. From 4543m (Middle Miocene Unconformity) to 4670m slow drilling (3-10 m/hr) was experienced over a mainly argillaceous limestone mixed with calcareous claystone interval. At 4670m lost 150psi on the standpipe pressure. Drilled from 4670m to 4692 where drilling was stopped for a couple of hours to work on the Top Drive System (TDS) and troubleshoot the MWD signal. Resumed drilling from 4692m to 4842.5m, coring point (target B Sand). Pumped tandem hole cleaning pills (50bbls of low-vis KCl brine 10ppg / 50bbls of hi-vis 13.2ppg KCl/Glycol SSWBM with 1.8ppg Barazan); while circulating the pills out lost 470psi on the standpipe pressure (suspected drill string washout). Pumped out of hole to 4767m, performed flowcheck and pulled on elevators to 4610m. Encountered multiple restriction between 4610m to 4507m. Wiped, reamed and lubricated out of hole from 4610m to 3651m. Pulled out of hole to surface. Found drill string washout (on the 5 ½” DP, 1849m from bit). This hole section was drilled with 11.6ppg Salt Saturated WBM/KCL/Glycol drilling fluid. No gains or losses recorded while drilling this section.

2.3.1.5.2 12 ¼” Coring Attempt & Cement Plug

A 27m long 8” x 5 ¼” core barrel with a 12 ¼” core head was made up and RIH having to ream down from 3651m to the bottom at 4842.5m. Attempted to start coring, no ROP, no torque recorded; the core barrel was jammed from the very beginning of the coring attempt. Backreamed out of hole to 4508m. String stalled out and packed off at 4508m. Attempted to free the stuck coring string with no success. Performed blind back off (targeting the safety joint 29m behind bit). Pulled the coring assembly to the surface; 208m of the coring BHA was left in hole (fish from 4508m to 4299m).

Ran in hole with 4" cement stinger above the fish and pumped 188bbls of 16.5ppg class G cement (set cement plug from 4281.5m to 3962m). Pulled to 3830m (4 stands above top of cement) and circulated out any contaminated mud. Pulled to surface with the 4” cement stinger.

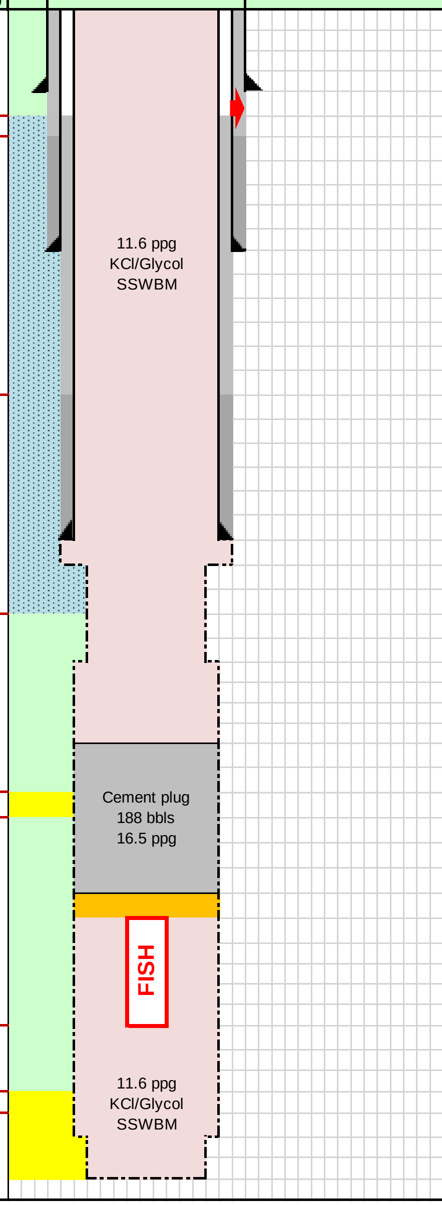
Karish North 01 ST 02 (KN 01 ST 02) Well Schematic

Rig	Stena DrillMAX	RTE (m)	31.6	Water Depth (m)	1,726

Casing / Liner Details

Size	Wgt (lbs)	Grade	Connection	Drift (in)	Cement Wt/Type Planned TOC	Mud Weight / Type	FIT / LOT (ppg)
36"	552.7	X-80	Leopard SD EF	31.265	Jetted	8.6 SW & Barazan hi-vis sweeps	N/A
	373.9	X-56	Leopard SD EF	31.265			
21" Ext. joint x 20"	21" 263.9	X-65	Swift DW2 HTAR	18.125	12.5ppg G Lead, 15.8 ppg G Tail, Surface	8.6 SW & Barazan hi-vis sweeps. 10.5ppg SSWBM from 2,735m	11.9
	20" 147.0	X-65		18.125			
13.5/8"	88.2	P-110	VAM 21	12.250	13.0 ppg G Lead, 15.8 ppg G Tail, 2749m MDBRT	11.5ppg SSWBM	12.5

Formation	MDBRT (m)	TVDBRT (m)
Seabed	1762	1762
Top Evaporite (Anhydrite)	2162.00	2162.00
Top Massive Salt (Halite)	2224.00	2192.00
ME20	3465.00	3425.80
Base Salt	3759.00	3719.10
Top Tortonian Sands	4084.00	4061.23
Base Tortonian Sands	4202.00	4159.10
Mid Miocene UC	4543.00	4434.00
A Sand	4685.00	4548.80
B Sand	4789.00	4636.20



Inc.	Description	MDBRT (m)	TVDBRT (m)
0°	Top HPWHH	1,758.08	1,758.08
	Top LPWHH	1,759.00	1,759.00
0°	36" Shoe	1,832.95	1,832.95
	20" Burst Disc	1,880.38	1,880.38
8.7°	20" Shoe	2,784.30	2,711.60
	20" TD	2,789.00	2,716.20
4.4°	13.5/8" Shoe	3,651.10	3,642.90
	17.1/2" TD / Rat-hole	3,656.00	3,647.80
3.7°	Start of ramp	3,680.00	3,671.74
	KOP	3,702.00	3,693.72
	13.1/2" Underream Se	3,769.00	
	TOC (tagged 10 klbs)	3,962.00	3,950.19
35.9°	End of build	4,188.80	4,148.41
	Base of cement plug	4,281.50	
	CST	4,294.00	
	Top of fish	4,299.00	4,237.12
	LIH - 12.1/4" coring as	4,508.00	4,405.73
36.2°	Start of drop	4,597.20	4,477.52
	13.1/2" Underream Se	4,799.50	
26.7°	12.1/4" TD	4,842.50	4,683.18

Figure 2-3 - Karish North 01 ST02 Well Schematic

2.3.1.6 Karish North 01 ST03 Operational Description

2.3.1.6.1 12 ¼” Hole Section Drilling 4002.0m – 5083.0m MD/3956.2m – -4886.4m TVDSS

12 ¼” PDC Bit was picked up and made up with 8” iCruise RSS and LWD string (ABG-Directional-EWR-DGR-PWD-Geotap) and ran in hole to 3651m (13 5/8” casing shoe). Washed and reamed down from 3651m to 3962m (TOC) and drilled out cement to 3984m. Initiated 12 ¼” sidetrack at 3984m and confirmed well sidetracked at 4002m (Kick off Point). Directionally drilled 12 ¼” hole section to 4101m where standpipe pressure has increased with 100psi and the string stalled on bottom. Continued drilling to 4162m where the string stalled again on bottom. This stalling tendency of the drill string continued until 4225m and it is related to the Tortonian Sandstone formation (interbedded friable, easy to drill Sandstone with harder Claystone and cemented Sandstone layers). Directionally drilled to 4543m (Middle Miocene Unconformity) where the ROP dropped significantly (0-8 m/hr) and stayed low until 4604m where 1500bbls of fresh SSWBM KCl/Glycol were added to the active and the ROP increased to 12-30 m/hr. The well was directionally drilled to 5083m (TD) without further problems. At TD the well was circulated clean prior to acquire the formation pressure tests with the LWD Geotap tool.

2.3.1.6.2 LWD Geotap Formation Pressure Tests

Once the 12 ¼” hole was cleaned and ready for logging with the LWD Geotap tool a correlation pass was performed in order to correct for the drill string compression / stretch. This was done over the 5081-5062m interval at higher logging speed (60 m/hr) in order to minimize the effect of the observed drag on the hole (30-50klbs over the normal up weight). A depth correction of +2.2m was applied after correlation. No other correlation pass was possible at later stages of the logging due to the high drag recorded on the hole. From the 27 pressure tests attempted over the C Sand Member, 15 tests were good. The maximum allowable time on station was 30min; after most of the tests were finished rotation on the drill string was applied in order to come free off station. Throughout the job washing and reaming were done as dictated by the hole condition.

At the end of the formation pressure testing programme the hole was reamed back to bottom. Backreamed from 5083m to 4530m where the drill sting became stuck with no circulation or rotation. After working the drill string up and down it was possible to gain rotation and the string came free; shortly after circulation was regained and continued to backream to 4385m. At this point it was noticed a 20% coverage over the shakers of fresh cuttings (12 ¼” Gun Reamer working at 39m above the bit) mixed with cavings (1-2cm, blocky claystone). Backreaming was performed all the way back to the 13 5/8” casing shoe (3651m) while the cuttings / cavings observed at the shakers reduced to traces. Circulation was continued with the 12 ¼” bit inside the 13 5/8” casing until the hole was clean. Performed flow check, well found static and pulled the 12 ¼” BHA to the surface.

2.3.1.6.3 KN01 ST03 Plug and Abandon

Ran in hole with 4” open ended mule shoe assembly to 4731m. Washed down / lightly reamed to 5083m (TD) where bottoms up was circulated.

Karish North 01 ST03 was abandoned by setting six cement plugs from 5078m to 3450m. Details about the cement plugs in the table below.

Barrier	Base (m MDRT)	Top (m MDRT)	Verification	Comment
Plug #6	3705	3450	Pressure test at 1700psi, OK.	191bbls 16ppg Class G cement
Plug #5	3818	3,709	TOC tag at 3709m with 10klbs.	184bbls 16ppg Class G cement
Plug #4	4133	3823	N/A	179bbls 16ppg Class G cement
Plug #3	4448	4138	N/A	163bbls 16ppg Class G cement
Plug #2	4763	4453	N/A	163bbls 16ppg Class G cement
Plug #1	5078	4768	N/A	163bbls 16ppg Class G cement.

Table 2-6 – KN01-ST03 Cement Plug Locations

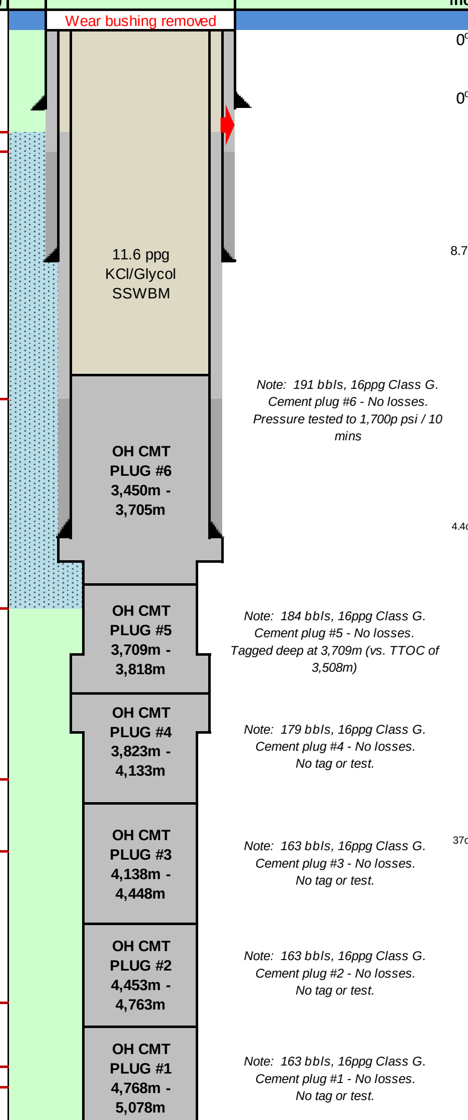
Karish North 01 ST03 (KN01 ST03) Well Schematic - SUSPENDED (06/11/19)

Rig	Stena DrillMAX	RTE (m)	31.6	Water Depth (m)	1,726

Casing / Liner Details

Size	Wgt (lbs)	Grade	Connection	Drift (in)	Cement Wt/Type Planned TOC	Mud Weight / Type	FIT / LOT (ppg)
36"	552.7	X-80	Leopard SD EF	31.265	Jetted	8.6 SW & Barazan hi-vis sweeps	N/A
	373.9	X-56	Leopard SD EF	31.265			
21" Ext. joint x 20"	21" 263.9	X-65	Swift DW2 HTAR	18.125	12.5ppg G Lead, 15.8 ppg G Tail, Surface	8.6 SW & Barazan hi-vis sweeps. 10.5ppg SSWBM from 2,735m	11.9
	20" 147.0	X-65		18.125			
13.5/8"	88.2	P-110	VAM 21	12.250	13.0 ppg G Lead, 15.8 ppg G Tail, 2749m MDBRT	11.5ppg SSWBM	12.5

Formation	MDBRT (m)	TVDBRT (m)
Seabed	1762	1762
Top Evaporite (Anhydrite)	2162.00	2162.00
Top Massive Salt (Halite)	2224.00	2192.00
ME20	3465.00	3425.80
Base Salt	3759.00	3719.10
Top Tortonian Sands	4082.50	4062.00
Base Tortonian Sands	4200.50	4161.00
Mid Miocene UC	4543.00	4434.00
A Sand	4685.00	4549.00
B Sand	4787.00	4635.00
C Sand	4919.00	4757.00



Inc.	Description	MDBRT (m)	TVDBRT (m)
	Protection cap installed / VX gasket removed		
0°	Top HPWHH	1,758.08	1,758.08
	Top LPWHH	1,759.00	1,759.00
0°	36" Shoe	1,832.95	1,832.95
	20" Burst Disc	1,880.38	1,880.38
8.7°	20" Shoe	2,784.30	2,711.60
	20" TD	2,789.00	2,716.20
4.4o	13.5/8" Shoe	3,651.10	3,642.90
	17.1/2" TD / Rat-hole	3,656.00	3,647.80
	Start of ramp	3,680.00	3,671.74
	KOP	3,702.00	3,693.72
	13.1/2" Underream Se	3,769.00	
	Top cement (12.1/4")	3,962.00	
	Top Ramp	3,984.00	3,970.91
	Kick off point	4,002.00	3,987.78
37o	End build / start tang	4,195.00	4,156.06
	End tang / start drop	4,700.00	4,562.00
	TD	5,083.00	4,917.95

Figure 2-4 - Karish North 01 ST03 Well Schematic

2.4 Reservoir Geology

The Karish North discovery is located in the same Early Miocene submarine fan deposits of the Tamar sandstones as the Karish Main, Tanin, Leviathan and Tamar fields. The Tamar sandstone formation in Karish North is in excess of 300m True Stratigraphic Thickness (TST) resulting in the field being underlain by well-developed Early Miocene aquifer sands which are expected to provide strong aquifer support.

The Tamar Sands regionally are further subdivided into more detailed reservoir units (A-D Sands, with A being stratigraphically the youngest) and separated by pelagic shales interpreted to be maximum flooding surfaces, representing maximum sea levels and temporary starvation of the Levant Basin sediment supply. The Karish North 01 and sidetracks have penetrated hydrocarbons within the B Sands and C Sands. No effective reservoir was found in the A sands, which are present in the Karish North field as hemipelagic mudstones. The Karish North D sands were penetrated within the aquifer, with reservoir quality sands being present. The D sands are expected to be gas bearing on the crest of Karish North, with the Karish North 01 penetrating the D sands too far downdip to intersect gas bearing sands. Formation pressure data from Karish North 01 ST01 and Karish North 01 ST03 show that locally the CD shale that sits between the C and D sands is a seal.

The main reservoir at Karish North is the massive, clean, Upper C Sand, which is also the main reservoir unit in Karish Main. The Upper C Sands at Karish are c.55m TST and of outstanding reservoir quality (500-1000mD). The Upper C Sands have been proven to be extensive across the entire Karish North structure, with an approximate 1:1 correlation between KN01 (crest) and KN01 ST03 over a distance of some 700m. Furthermore, the Upper C sands correlate very well with Karish Main wells over some distance of 5km The Upper C sands are interpreted as distal lobe turbidite sheet sands, verging on grainflow deposits.

The Upper C sands are underlain by the Lower C sands, which are heterogenic in nature and represent distal, off-axis deposits. The Lower C sands are c.100m TST and have excellent (0.19 porosity, 500Md) net reservoir quality.

The B Sands at Karish North appear to be more distal/marginal turbidite deposits, relative to the C and D sands. This in part is thought to be due to the growth of the Karish North structure during the early Miocene (post deposition of the laterally unconstrained C and D sands), resulting in predominantly dilute flows and fine grained sediment depositing Tamar sands over what was a bathymetric high. This results in the Sands being thinly bedded with conventional formation evaluation failing to adequately capture the true input of net reservoir sands within the B Sands. The Karish North 01 has the benefit of a microresistivity data that shows the B sand net-to-gross to be higher (0.25) than conventional petrophysical analysis would calculate. Within the thinly bedded background of the B sands, are three sands which are resolvable with conventional logging tools. These are the B1, B2 and B3 sands from stratigraphically older to younger. These sands are typically <2m TST, thickening marginally from crest (KN01) to flank (KN01 ST03) and are perfectly correlatable (both on logs but also biostratigraphy) between Karish North and Karish Main, highlighting that all reservoir unit, even as thin as 2m TST are continuous and extensive across the Karish Lease.

2.5 Stratigraphy of the Karish Complex Gas Fields

Please see Karish and Tanin Field Development Plan (2017)

2.6 Seismic Interpretation

2.6.1 3D Seismic Data

2.6.1.1 Polarity of Seismic Data

3D seismic data acquired by PGS in 2010 (EME-10) covered the entire Karish Lease. The seismic data was re-processed zero-phase PSTM and PSDM by Down Under Geo-solutions in 2019. The polarity of the data is SEG Normal (**Figure 2-5**), i.e. an increase in acoustic impedance is a zero phase peak. **Figure 2-6** illustrates the seabed horizon on the PSDM volume

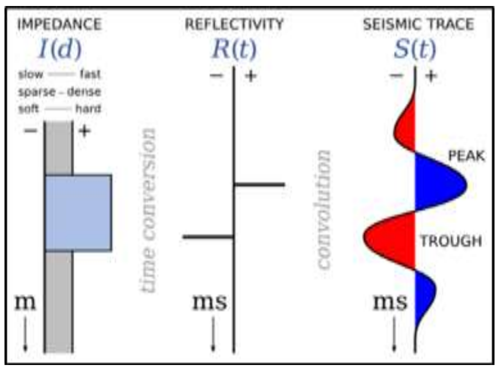


Figure 2-5 S.E.G.normal polarity. Increase of acoustic impedance is a zero phase peak

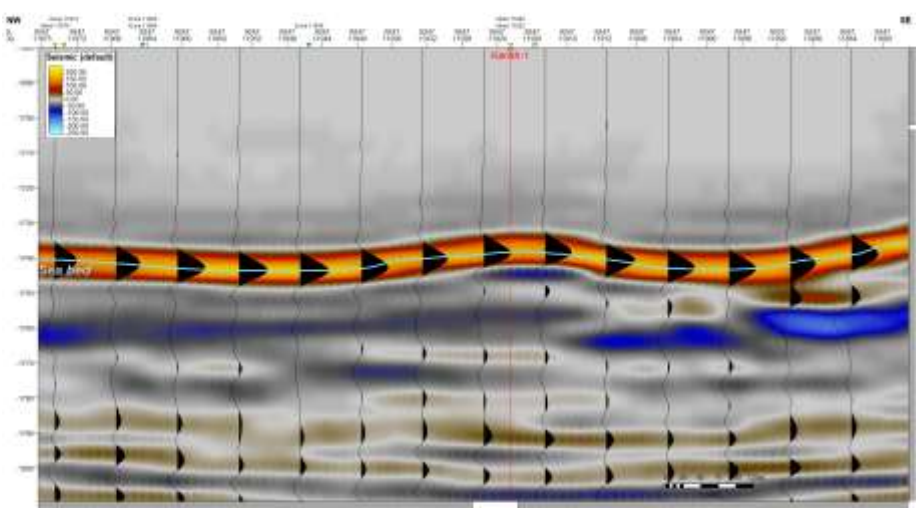


Figure 2-6 Seabed reflector from the PSDM D seismic volume at the Karish-1 well (inline 9274). Red is a peak

2.6.2 Synthetic Seismograms and Phase Analysis

2.6.2.1 Karish-1 Well

Baker Hughes acquired good quality sonic and density wireline logs over the 12.25” and 8.5” sections using the XMAC and ZDL wireline tools. Both curves were edited and spliced to produce continuous curves from 3160mMD to 4790mMD (**Figure 2-7**). A VSP was also acquired over the interval 4305-4765mMD, a total of 225 stations. The compressional sonic has been calibrated to the VSP first arrivals with a polynomial trend. The overall drift was in the range of -3 to 3ms. The wavelet used is a statistical wavelet.

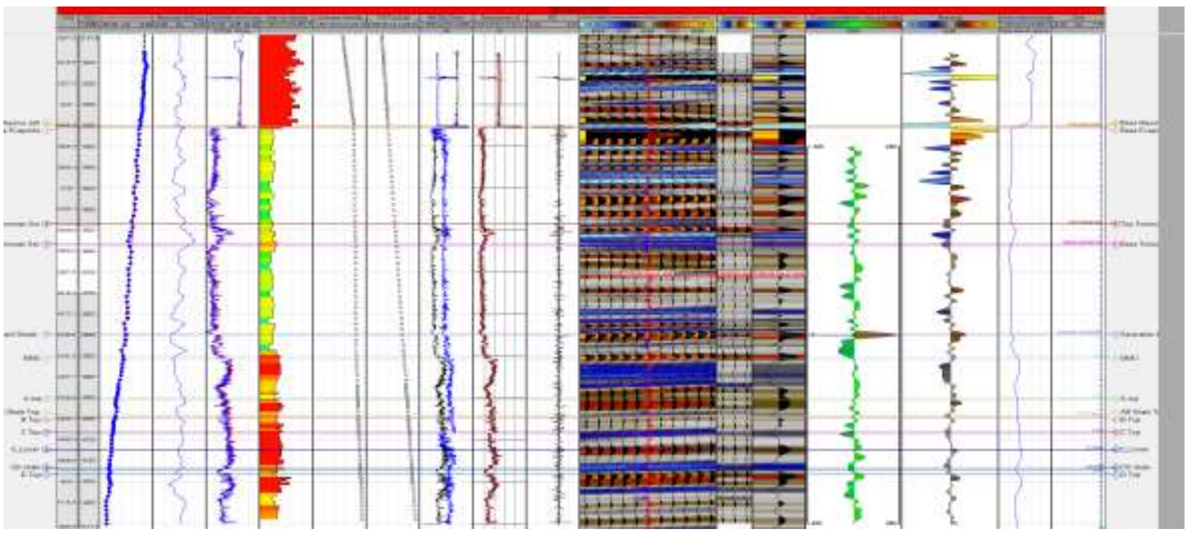


Figure 2-7 Sonic Calibration for Karish-1 well. The wavelet that has been used is a statistical wavelet.

Synthetic seismograms were generated and deterministic wavelet extraction has been performed. The resulting well tie is excellent (**Figure 2-8**). The wavelet extraction reported high predictabilities (70%). A time shift of +5ms was used to match the seismic data. The majority of reflectors show an excellent match.

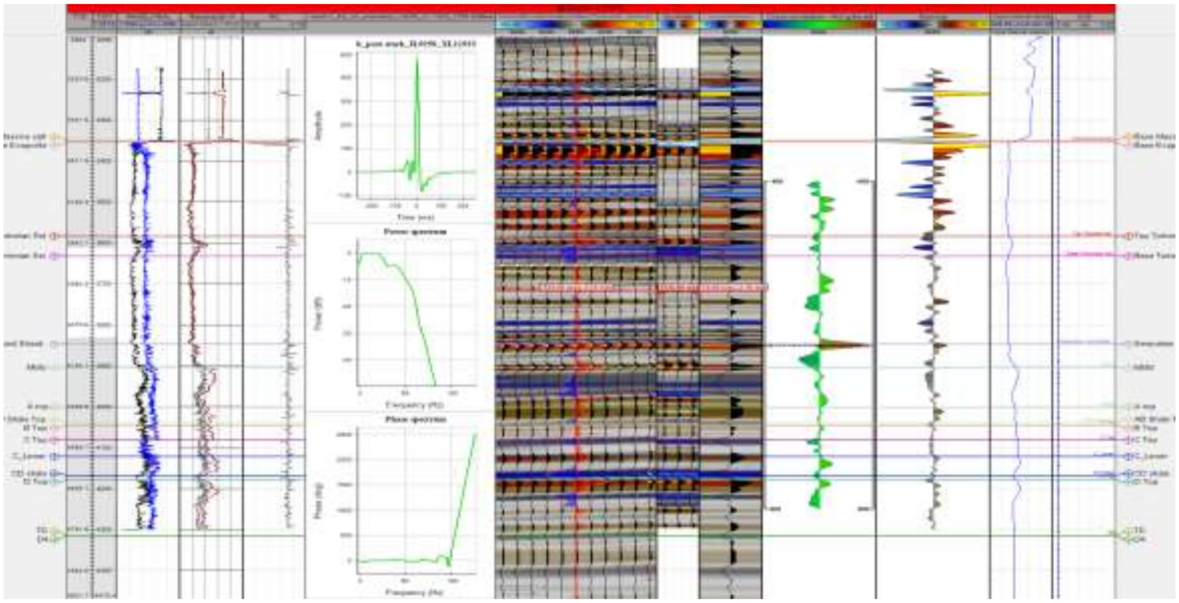


Figure 2-8 Karish-1 seismic well tie. The majority of reflectors shows an excellent match.

2.6.2.2 Tanin-1 Well

Baker Hughes acquired the sonic and density wireline logs over the 12.25" and 8.5" sections using the XMAC and ZDL wireline tools. Both curves were edited and spliced to produce continuous curves from 3645mMD to 5500mMD (**Figure 2-9**). A VSP was also acquired in two runs over the interval 1797-4634mMD, a total of 225 stations.

The compressional sonic curve was calibrated to the check-shots at lithological boundaries. The VSP corridor stack and synthetic seismogram show an excellent match.

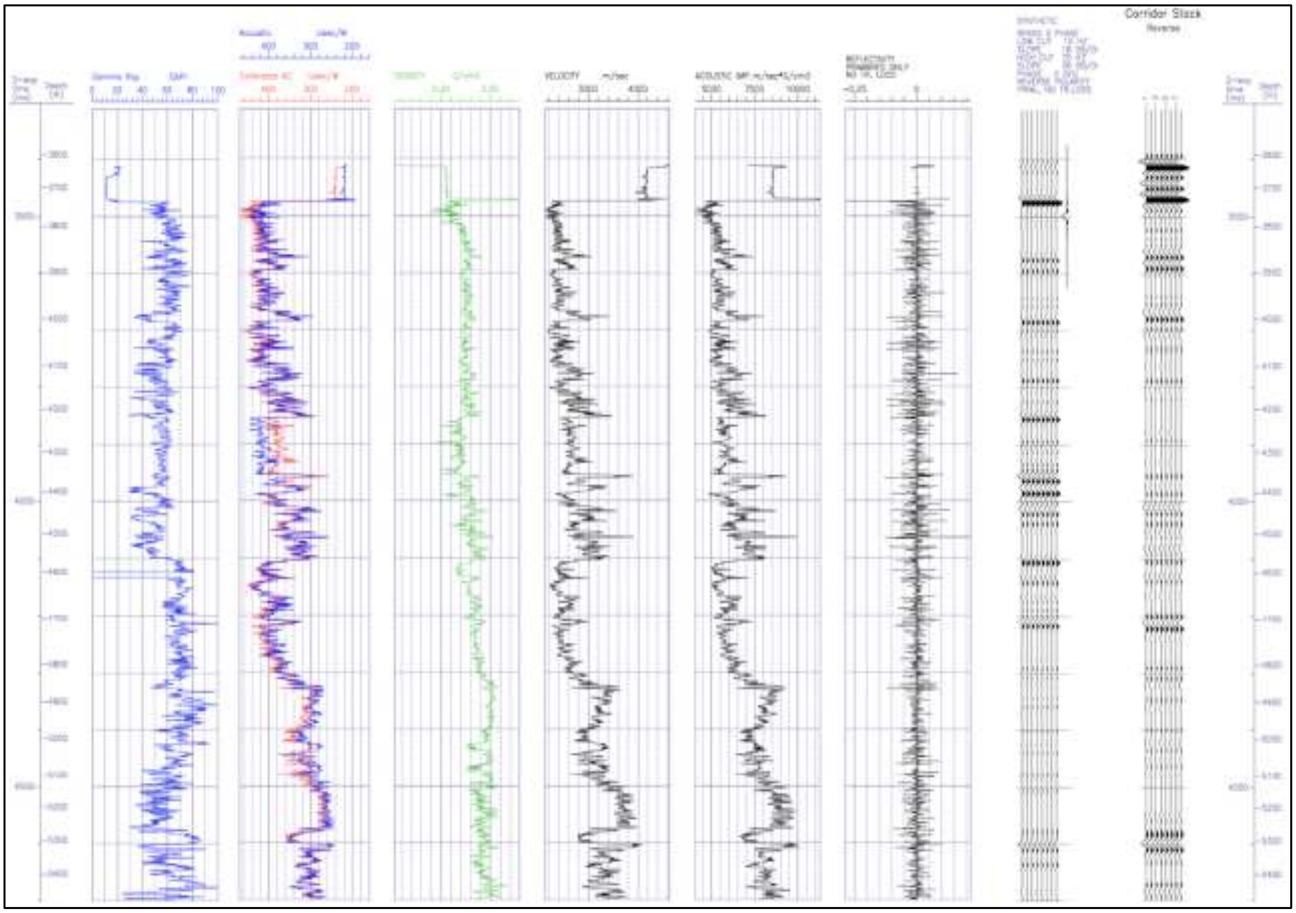


Figure 2-9 Sonic calibration, synthetic seismogram and corridor stack (normal S.E.G. polarity) generated by VSFusion for Noble Energy.

2.6.2.3 Karish Main-02 Well

KM-02 was drilled in a crestal location close to the ESE-NNW fault that bounds the Karish field from the North. The 3D seismic in this area is poor quality due to the fault shadow of the fault. The area was not considered suitable for wavelet extraction. Sonic calibration was performed using a statistical wavelet.

The compressional sonic curve was calibrated to the check-shots at the main geological boundaries. The overall sonic drift is in a range of -2 to 2 ms. An additional 13 ms shift has been applied for optimal match to the seismic data. Overall the seismic well tie was very good (**Figure 2-10**).

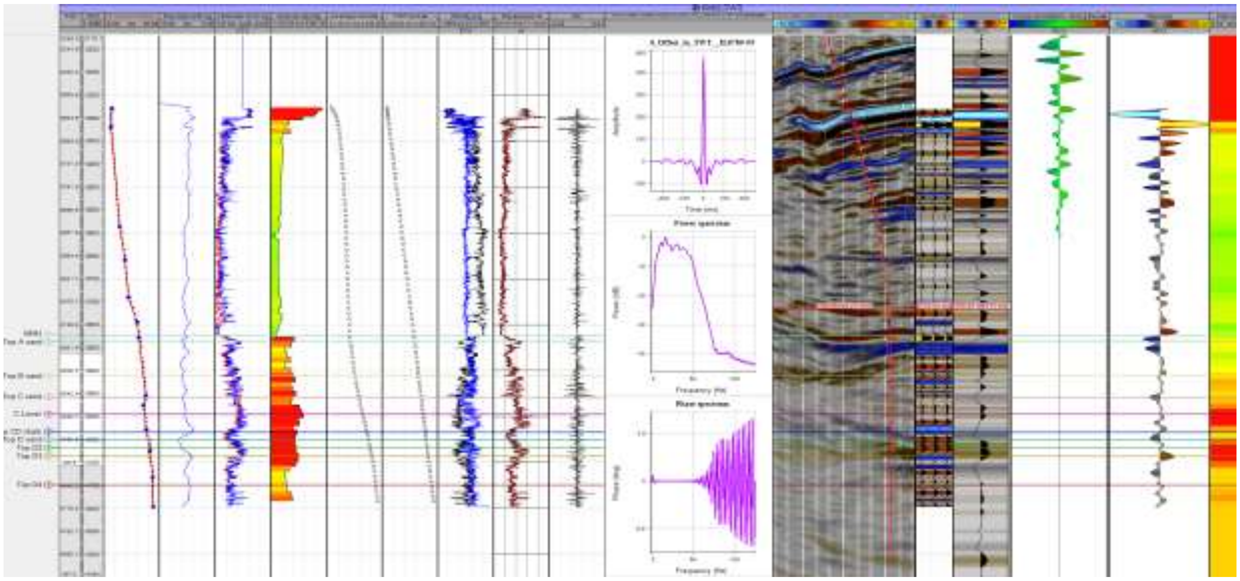


Figure 2-10 Integrated seismic well-tie for Karish Main-02 well. The well tie suggests a very good match with the seismic.

2.6.2.4 Karish North-01 Well

In order to achieve a well tie in Karish North-01 well (**Figure 2-11**) a shared checkshot has been used from Karish North-ST01 well. The synthetic seismogram shows a very good match. The predictabilities from the wavelet extraction were around 50%. The time shift that has been applied is 4ms.

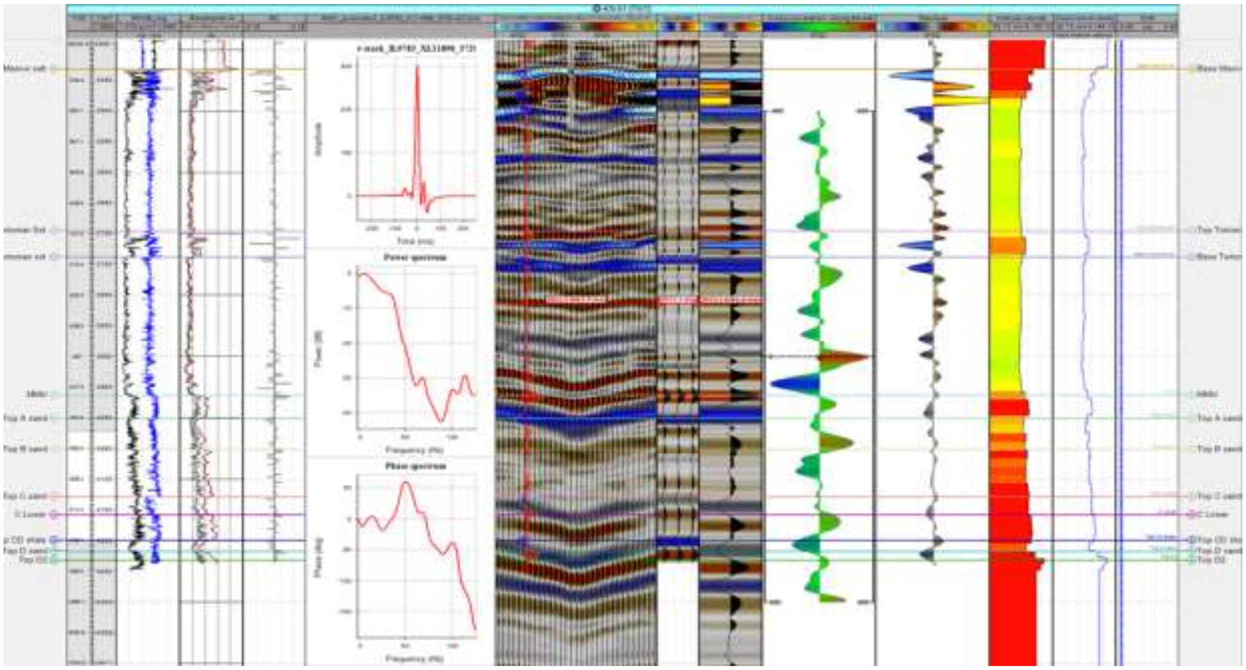


Figure 2-11 Seismic well tie in Karish North-01 well. It shows a very good match.

2.6.3 Seismic Markers

2.6.3.1 Regional Seismic Markers and Seismic Facies

The regional seismic markers are consistent across the Karish Complex. **Figure 2-12** shows the seismic reflection characteristics of the seismic stratigraphic packages from Middle Jurassic to present.

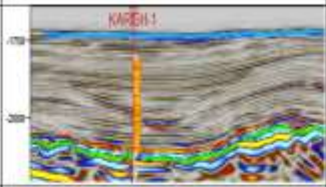
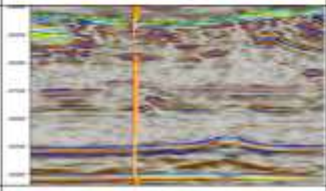
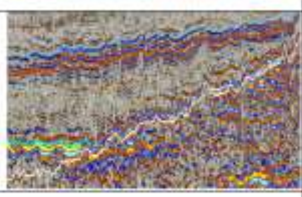
	Seismic Reflectivity	Seismic Horizon	Thickness (m)	Reflection Characteristics	Interpretation
Plio/Pleistocene		Seabed Top Evaporite	250 to 450	Characterised by high frequency low amplitude reflectors. Subparallel wavy to lenticular configurations. Onlapping onto to structures generated by underlying salt movements.	Deep water depositional system controlled by the underlying salt movement. Strong seabed reflector
Messinian Evaporites		Top Evaporite Intra Evaporite Base Evaporite	1550 to 1720	The upper interval shows discontinuous high amplitude reflectors folded and at places thrust imbricates are visible. The lower section is largely transparent with high amplitude parallel reflectors at the base of the salt.	Mobile halite dominated system with subordinate rafted clastics and evaporites. The halite mobility is gravity driven causing extensive folding and thrust imbricates.
U. Miocene - Post Tamar Sands		Base Evaporite MMU	900 to 2400	Predominantly extensive parallel high amplitude reflectors. The middle interval becomes more discontinuous and chaotic characterised by low amplitude reflectors	Deep water depositional system. Possible amalgamating basin floor fans
E. Miocene - Tamar Sands		MMU Top Tamar Sands Top B Sand Top C sand Top D Sand Top 3.5D Sand	250 to 350 A to D sands	Extensive parallel high amplitude reflectors. The upper part of the Tamar sands appears to be truncated.	Basin floor fans system
Jurassic - Eocene		Top Eocene Cretaceous Top Jurassic		Parallel high amplitude reflectors are visible below the Top Eocene and Top Cretaceous horizons. Predominantly the interval is characterised by low amplitude reflectors affected by poor seismic quality.	The Cretaceous-Eocene interval onlaps onto the Jurassic highs.

Figure 2-12 Seismic reflection characteristics of seismic stratigraphic packages

2.6.3.2 Reservoir Interval Seismic Markers

The early Miocene Tamar Sands are sand-rich, extensive, deep-water turbidites. The Tamar sands are easily correlated across the Tanin-1, Karish-1 and Tamar-1 (Christiansen et al, 2013) wells. Tamar Sands are subdivided into four major sand units (A, B, C and D Sands).

No significant occurrences A Sand were penetrated probably due to extensive erosion at the crestal areas of the Complex. Therefore the down-truncating surface was picked on the inflection point defining the upper horizon to the Tamar Sand package. **Figure 2-13** shows the Top Tamar Sands reflector also referenced in the document as “Top A Unconformity” pick.

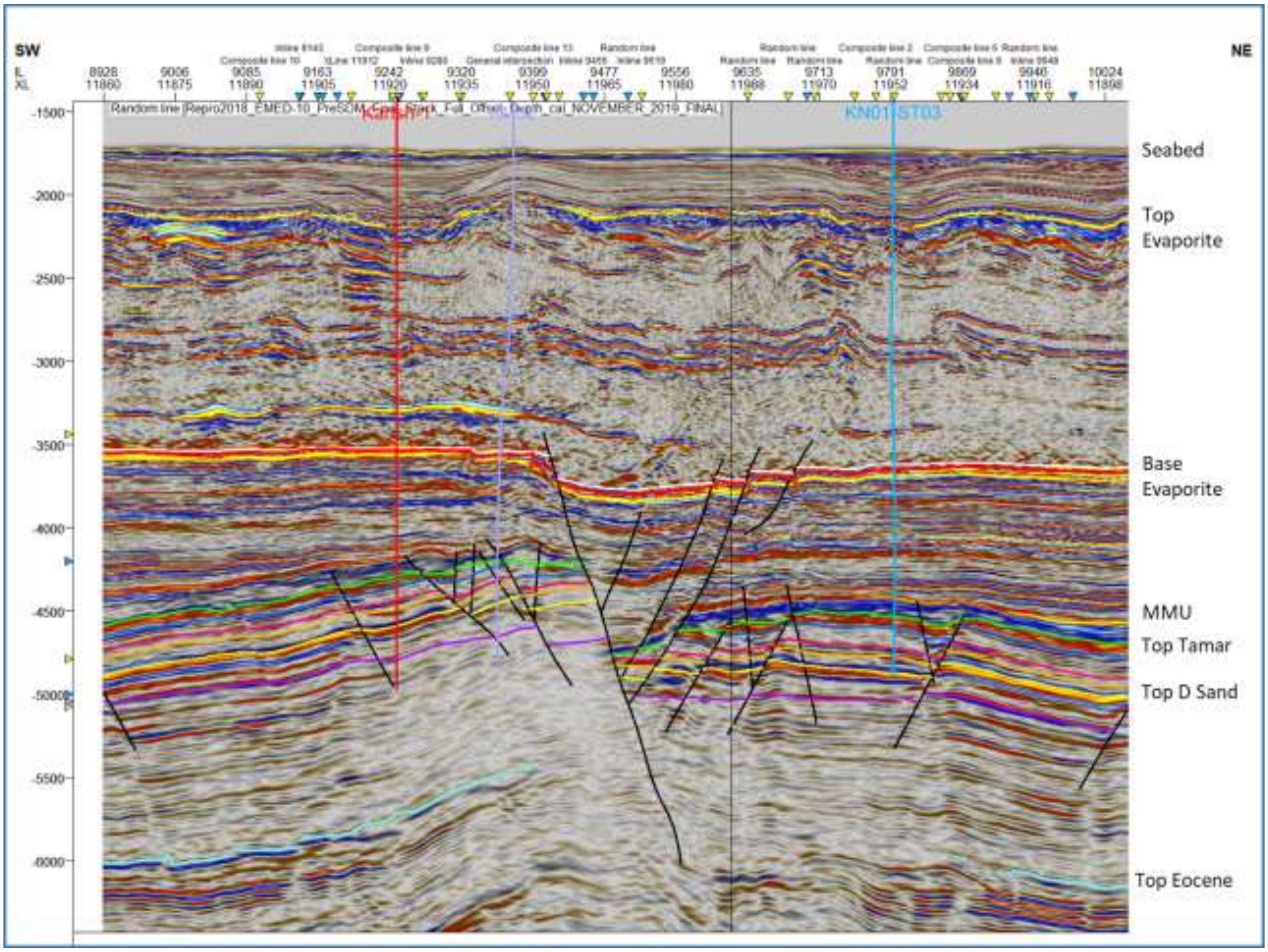


Figure 2-13 Composite seismic section through Karish-1, Karish Main-02 and Karish North-01ST03 showing the major seismic markers.

The Top B Sand is picked on a trough. The acoustic impedance contrast across the interface is weak but clearly defined.

Top C Sand is represented in seismic as a trough, however due to the gas effect a decrease in AI is evident.

2.6.4 Karish Complex Intepretation

2.6.4.1 Horizon Interpretations

The re-processed Kirchhoff Pre-SDM 3D seismic volume was used for the interpretation of the Karish Complex. **Figure 2-14** explains the identification of the seismic markers associated with the individual sand units as taken in Karish-1 well seismic tie.

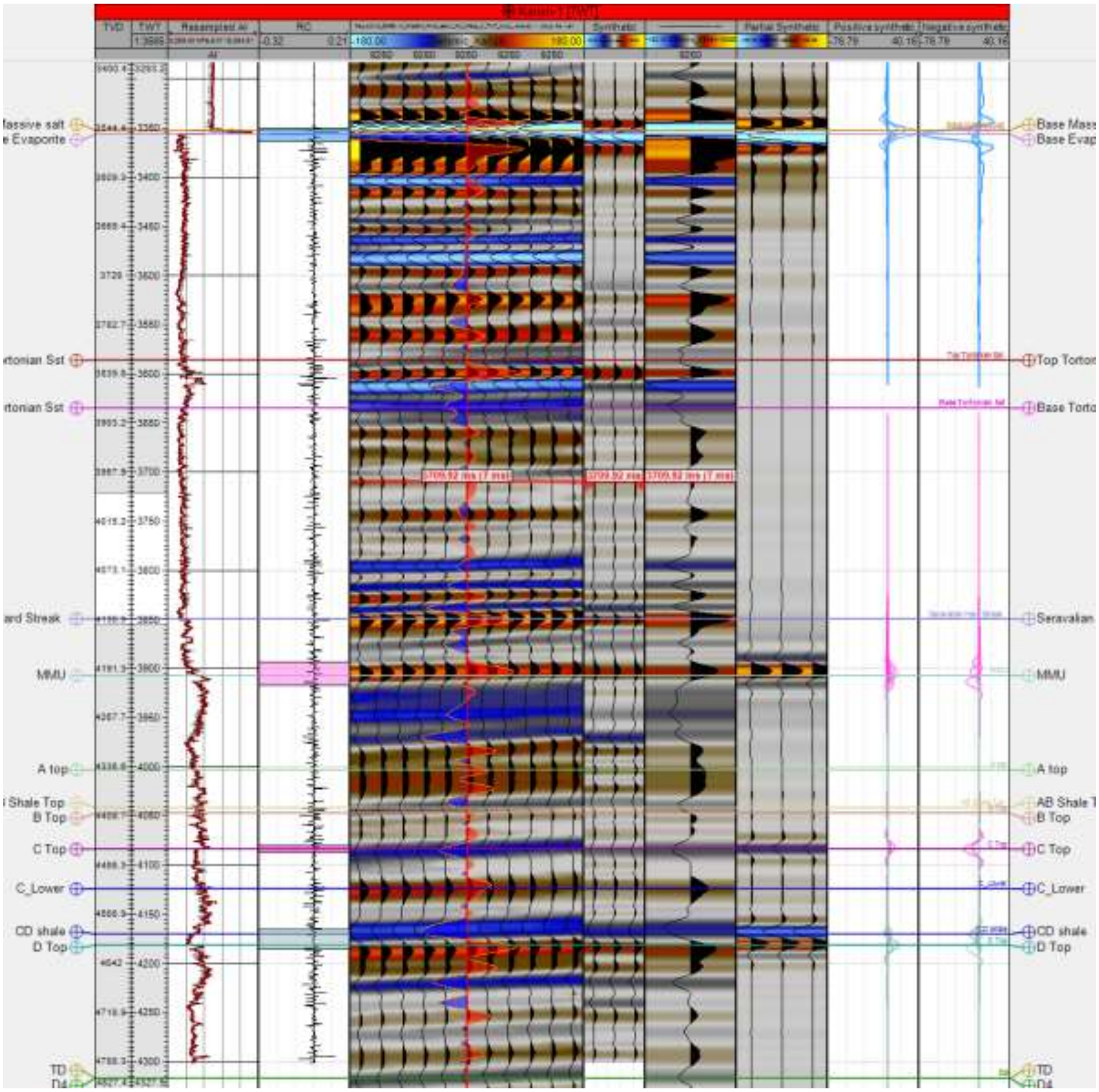


Figure 2-14 Seismic markers and formation well tops at Karish-1.

Top A Sand was absent in the Karish wells, and probably over most of the structural highs of the Karish Complex. Therefore, the unconformity truncating downward into the A Sand was interpreted instead. The A Sand appears to thicken towards the flanks of the Karish Complex. Towards the crest of the Karish North structure the A sand is expected to thin and potentially be eroded or not deposited at all.

Figure 2-15 shows minor erosional events (black lines) prior to the major unconformity. The exposed shoulders of the footwalls are affected by erosion together with the channel erosion on the corresponding hanging walls. The channel fill is composed of reworked sandstones and hemiplegic mud rich sediments.

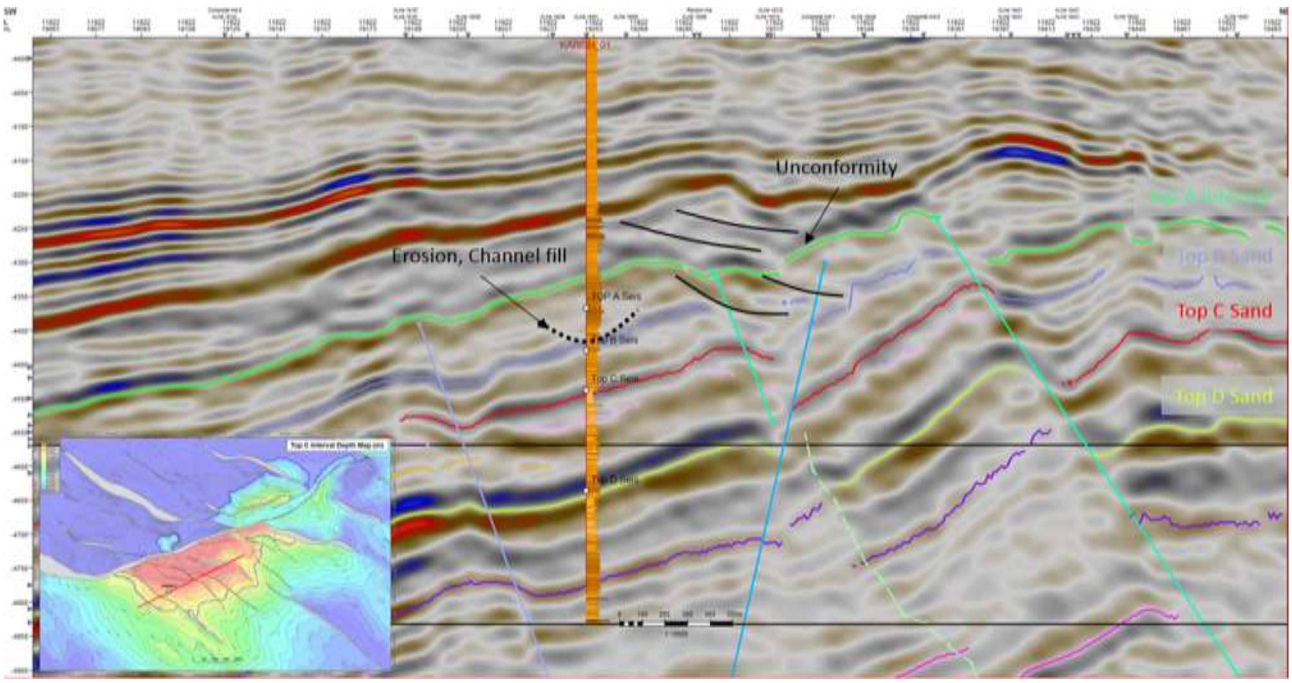


Figure 2-15 Arbitrary seismic line. Eroded A Sand at the location of the Karish-1 well (broken black line)

The seismic quality of the interpreted Top A Tamar Sands is affected by the following factors (**Figure 2-16**):

- The seismic quality diminishes below the fault shadow of the E-W oriented north-bounding fault separating Karish Main from Karish North.
- Overburden lateral velocity variations affect the continuity of the Top A Unconformity reflector.
- The overlying interval on-laps the A sand. Therefore, the acoustic impedance varies at the crest of the structure.
- The crest of the structure appears eroded as shown on **Figure 2-16**.

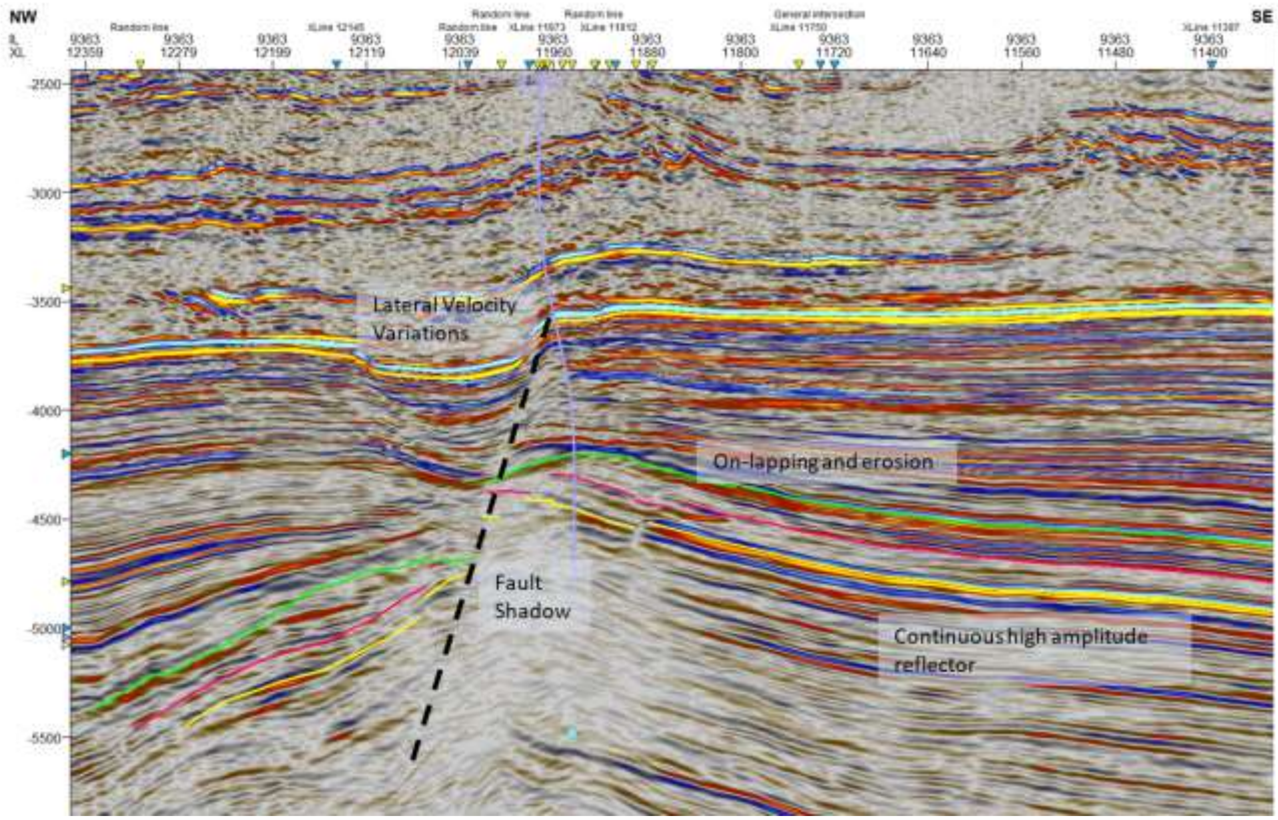


Figure 2-16 Inline 9363 highlighting the factors affecting the quality of the interpreted horizons.

The Top B Sand horizon (**Figure 2-13**), is picked on a low amplitude reflector affected mostly by the poor seismic quality associated with the faults as described above. The Top D Sand horizon trend was used to calibrate the Top B surface at areas of poor seismic quality. In a similar manner to the Top A Sand, the quality of the Top B picked reflector is excellent away from the Karish Complex structural highs.

The Top C Sand reflector shows generally a weak amplitude response, the reflection strength is predominantly due to the density contrast at the interface. The reflector becomes discontinuous in poor seismic quality areas discussed earlier. Additionally, tuning effects between the Top C Sand reflector and the reflector associated with the gas-water contact are also affecting the seismic quality of picked interpretation. Similarly, the Top D Sand horizon trend was used to guide interpretation of Top C sand in areas where seismic quality lacks fidelity.

The Top D Sand was interpreted over the entire lease. The quality of the interpreted horizon is excellent. The Top D Sand interpretation was robust in the low seismic quality areas as described above. Subsequently the Top D Sand trends were used to guide the interpretation of shallower horizons.

2.6.4.2 KN complex fault blocks and connectivity

Figure 2-17 shows the static model and the fault blocks that defined the Karish North complex. The interpretation over the KN North Crest area is high confidence over all horizons. All KN wells were drilled in this fault block. The wells were key in understanding the lateral velocity anomaly caused by the fault shadow of the E-W fault.

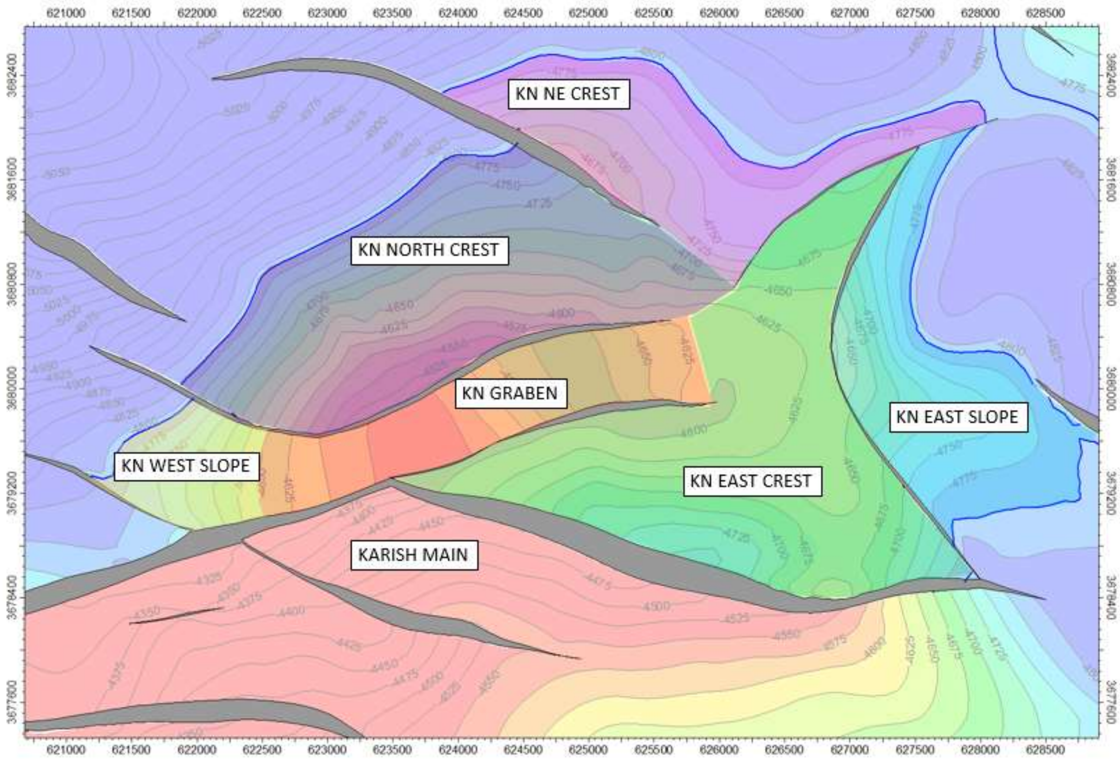


Figure 2-17 Assigned names of the Karish North Complex fault blocks.

The KN North Crest is partially separated from the KN NE crest area by a NW-SE fault that tips out to zero throw towards the SE. The fault is not sealing since the C Sand thickness is more than 45m. **Figure 2-18** describes the lateral throw of the NW-SE fault using three consecutive seismic lines (A, B and C).

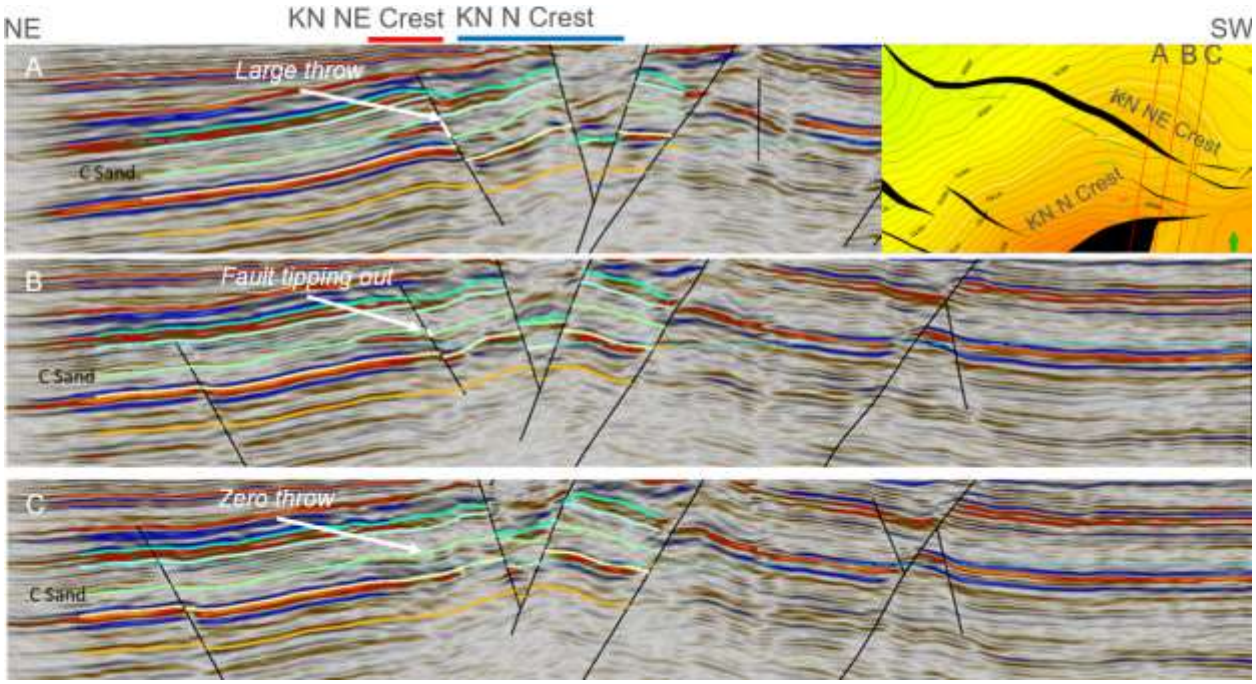


Figure 2-18 Seismic lines A, B and C showing the throw of the fault across the NW-SE fault separating the KN N Crest and the KN NE Crest.

Seismic line A the most northern of the three lines shows the largest fault throw. Line B, the middle seismic line, shows the fault tipping out, and finally line C, the most southern line, shows that the fault throw is zero.

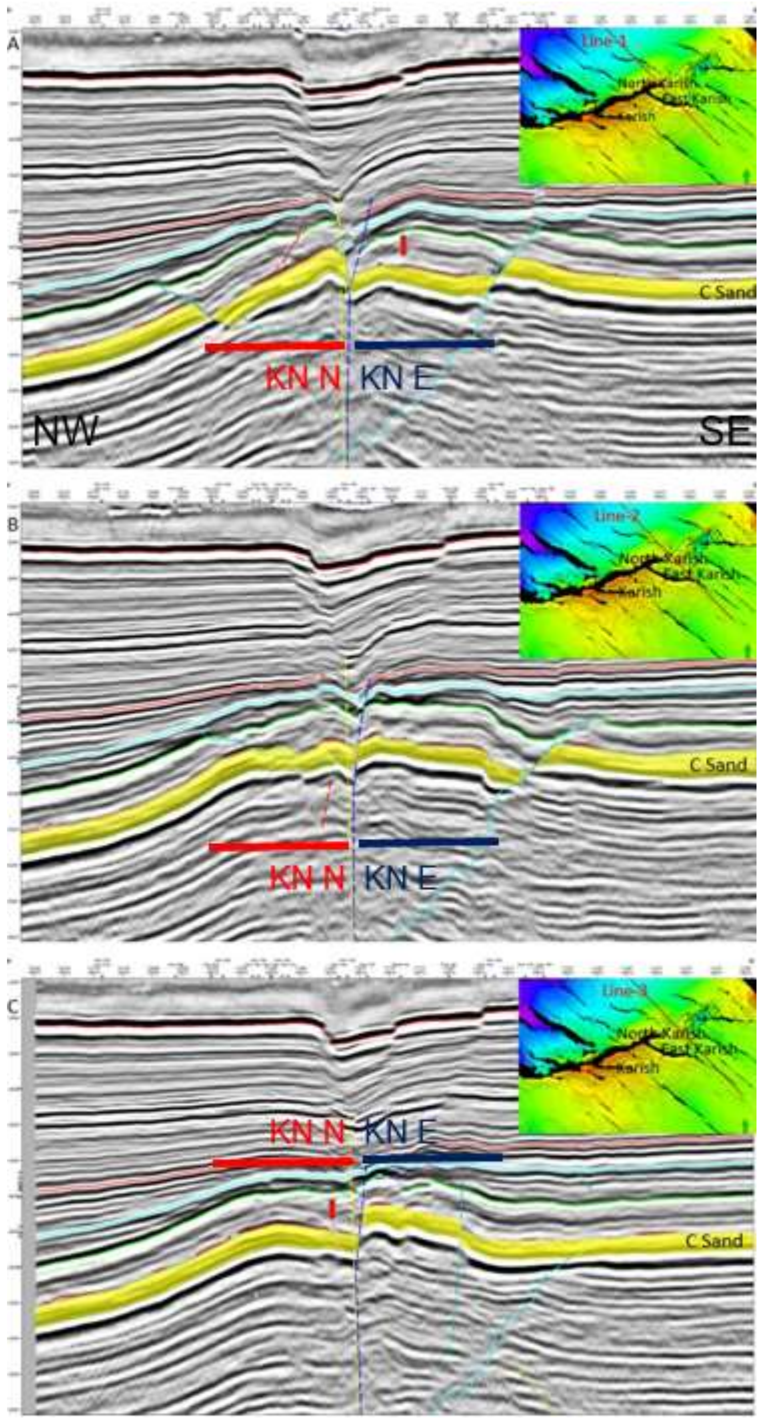


Figure 2-19 Juxtaposition of the KN-N crest and KN-E crest blocks across the ENE-WNW fault.

The ENE-WNW fault bounds the KN N crest block from the south. The throw of the fault is variable across the KN N Crest and KN E Crest as is shown in **Figure 2-19**. Seismic line 1 the most western line shows the

KN E crest being downthrown compared with the KN N crest. Line 2 shows that the C sand interval shown in yellow is perfectly juxtaposed across the two blocks. Finally line 3 the most eastern line shows that the KN N crest is downthrown compared to the KN E crest. Therefore, it is evident that the fault throw is varying like a “scissor” between the two blocks suggesting that the two blocks have perfect juxtaposition and connectivity across a section of the fault.

The KN E crest from the south is bound by a NE-SW trending “fault zone”, which is unique over the entire Karish Complex region. The fault zone we believe is composed of a series of small en-echelon faults connecting the first order Riedel strike-slip faults with the NW-SE faults. The faults have ramps between them therefore lines across the “fault zone” (**Figure 2-20**) appear to have variable throw.

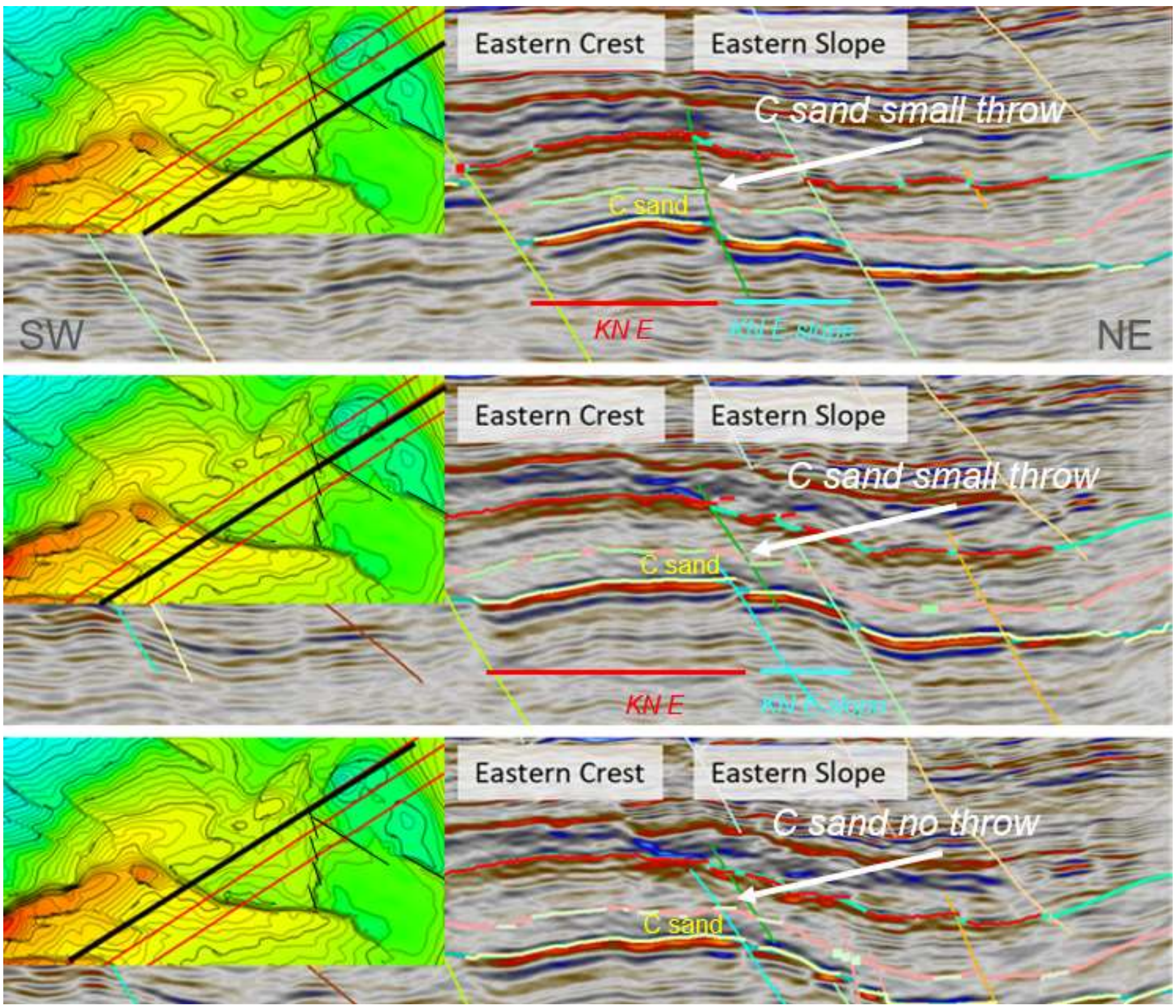


Figure 2-20 seismic line along the strike of the “fault zone”, described in the text

The top seismic line in shows a small throw at the C sand level, the line is the most southeastern. A smaller throw is shown in the middle seismic section over the C sand juxtaposition. The bottom seismic line shows the most northwestern line, the throw is sub seismic resolution and is broken into smaller faults.

An arbitrary seismic line is shown on **Figure 2-21** starting from the KN western slope through the KN graben area ending in the KN E crest area. The line indicates the degree of erosion that the Tamar sands have suffered within the graben. The erosion of the C sands is not conclusive since the imaging of the reflectors is poor in the graben area since it is affected by the shear zone.

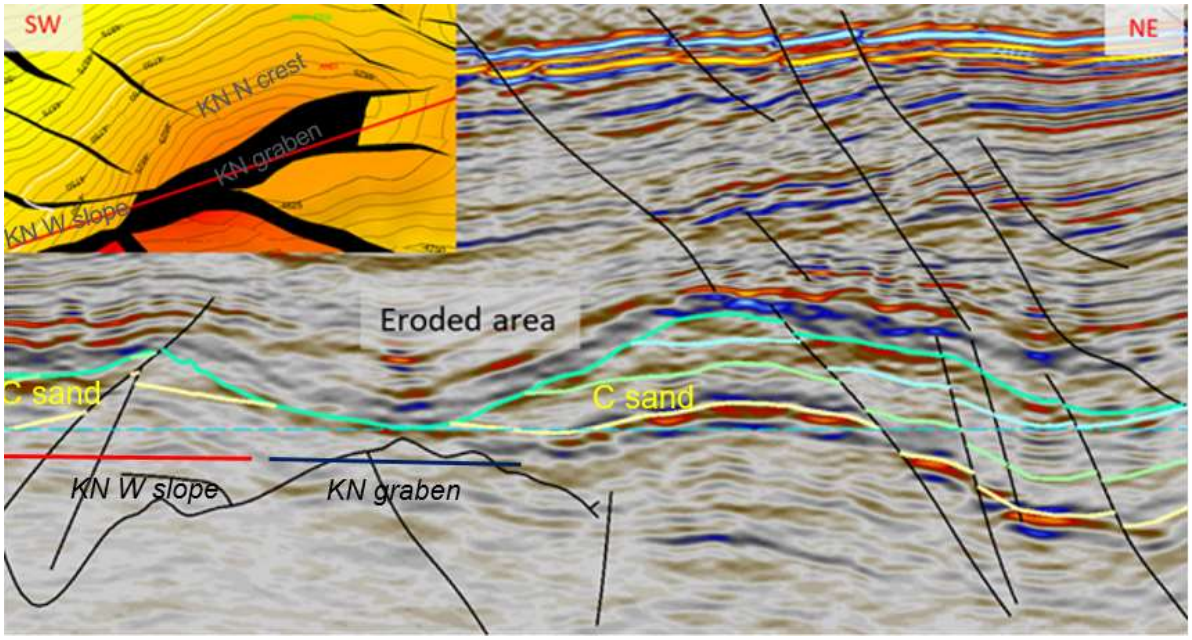


Figure 2-21 Arbitrary line through from the KN western slope to the KN graben area.

The KN crest, Westren slope and NE crest blocks show strong DHI attributes similar to the Karish Field. The KN E crest, E slope and graben show weak DHI evidence. **Figure 2-22** shows the spectral decomposition of the Karish Complex showing structurally conformance. The seismic quality over these areas is affected by abrupt lateral velocity variations at the base of the Messinian salt layer (1.3km thick) and the fault shadow of the ESE-NWN shear zone. The DHIs are equally affected at the crest of the Karish Field by the same factors.

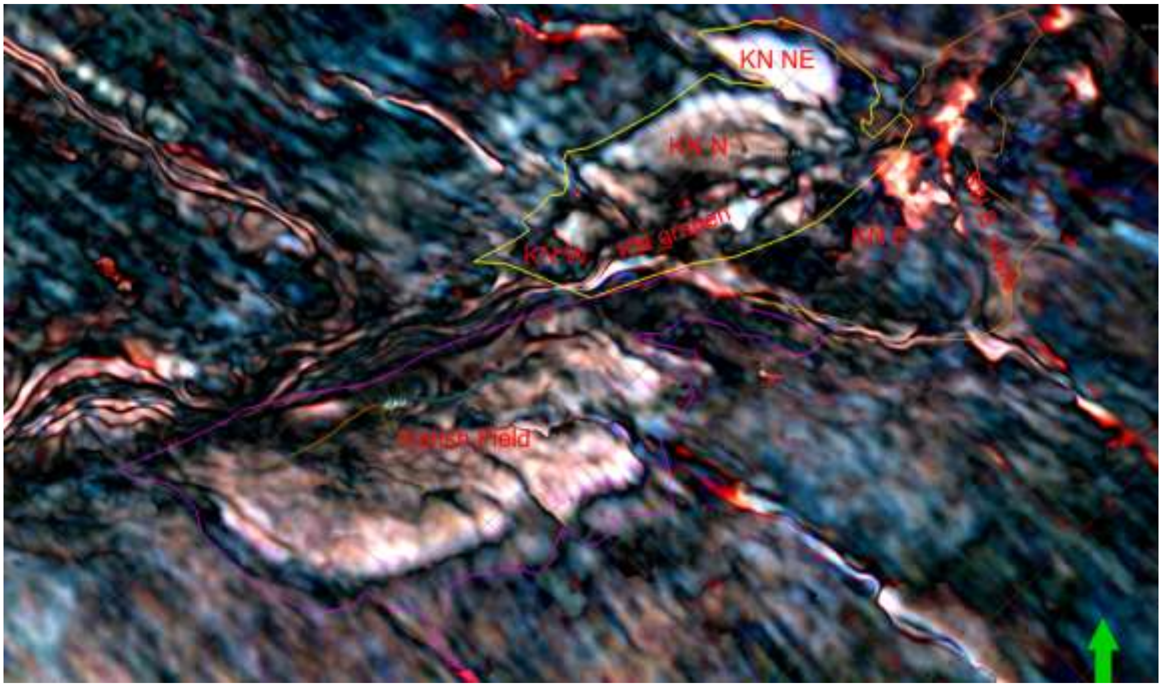


Figure 2-22 spectral decomposition of the Karish Complex showing structurally conformance.

2.6.5 Depth calibration of the PSDM cube

The purpose of this study was to calibrate the Karish PSDM cube that has been re – processed by DUG in 2018. Following the drilling of the Karish North wells residuals have been identified between the seismic and the well top formations. The velocity model strategy that have been followed was to calibrate the seismic interval velocities with the well interval velocities. Key horizons have been interpreted (seabed, Top salt, Base salt, MMU and D sands) converted to TWT using the migration velocities and then converted back to TVD using the calibration model. All models have been QCed over the well locations.

The available data for the study was:

- Seismic migration velocities
- VSP survey for the wells:
    - Karish – 1.
    - KM02.
    - KM03_ST1.
    - KN01_ST1.
- Vp log for the wells:
    - Karish – 1.
    - KM01 (only on shallow level).
    - KM02.

- KN01.

2.6.6 Migration velocity model QC

The migration velocities seems to predict with low residuals the depths in the Karish main (Karish – 1, KM02, KM01) area, however in the Karish north area the residuals were higher especially in the top of D sands. The residuals are higher in the Karish North area as can be observed from the synthetic seismograms.

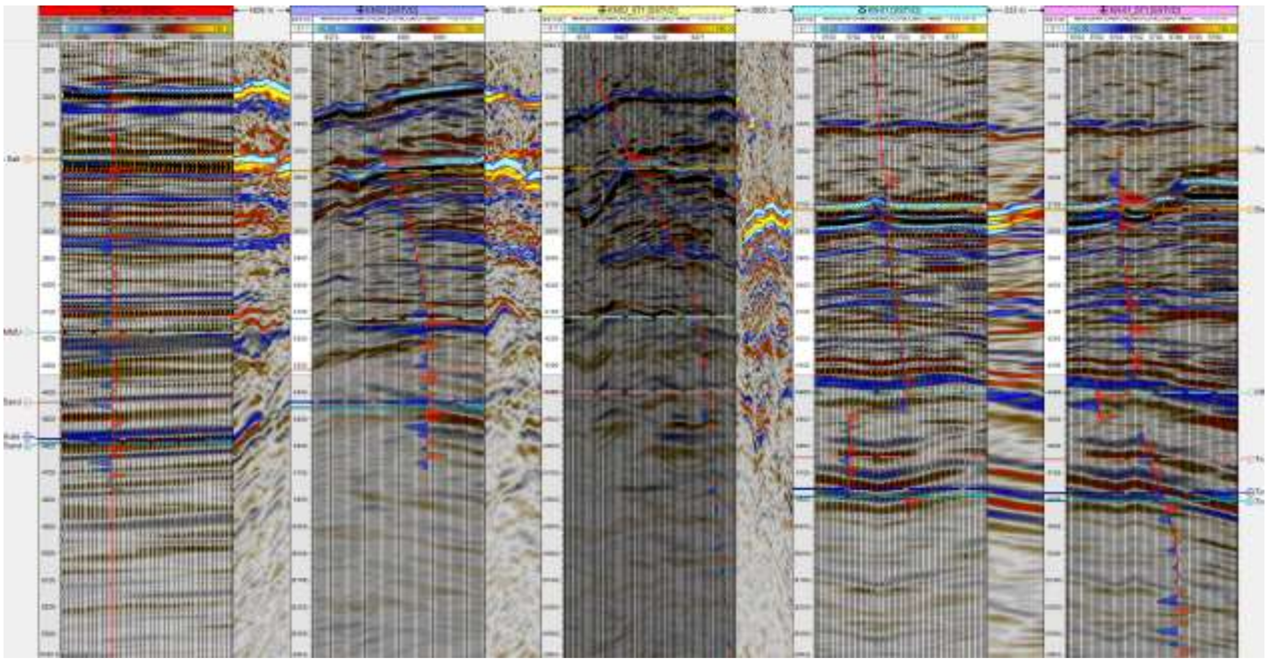


Figure 2-23 Synthetic seismograms in depth

Black is the Vp log, Blue is the VSP interval velocities, orange is the seismic instantaneous velocities.

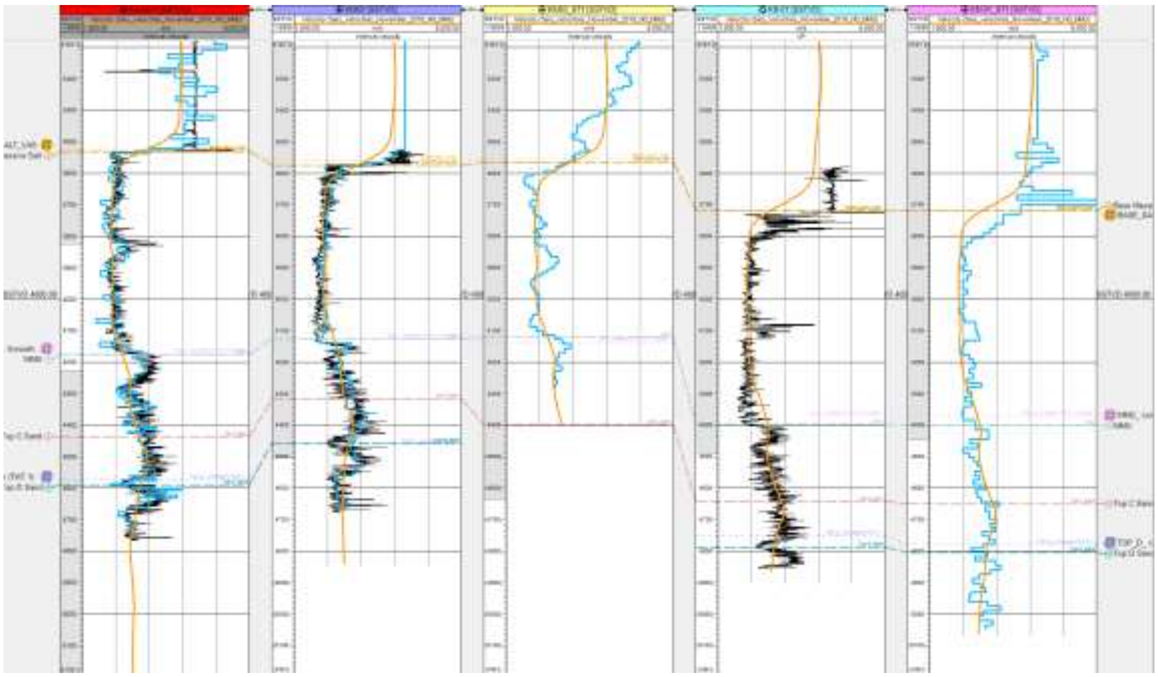


Figure 2-24 Migration velocities QC

2.6.7 Interval velocities maps

Interval velocities were extracted from each interval of the velocity model. Second step was the calculation of well interval velocities at the well locations. The well interval velocities have been gridded using as secondary trend the seismic interval velocities. Velocity maps quality-controlled in order to maintain the seismic trend.

On **Figure 2-25**, on top are the seismic interval velocities (from left to right: Top salt, Base salt, MMU, Top D). At the base are the well-calibrated interval velocities (from left to right: Top salt, Base salt, MMU, Top D).

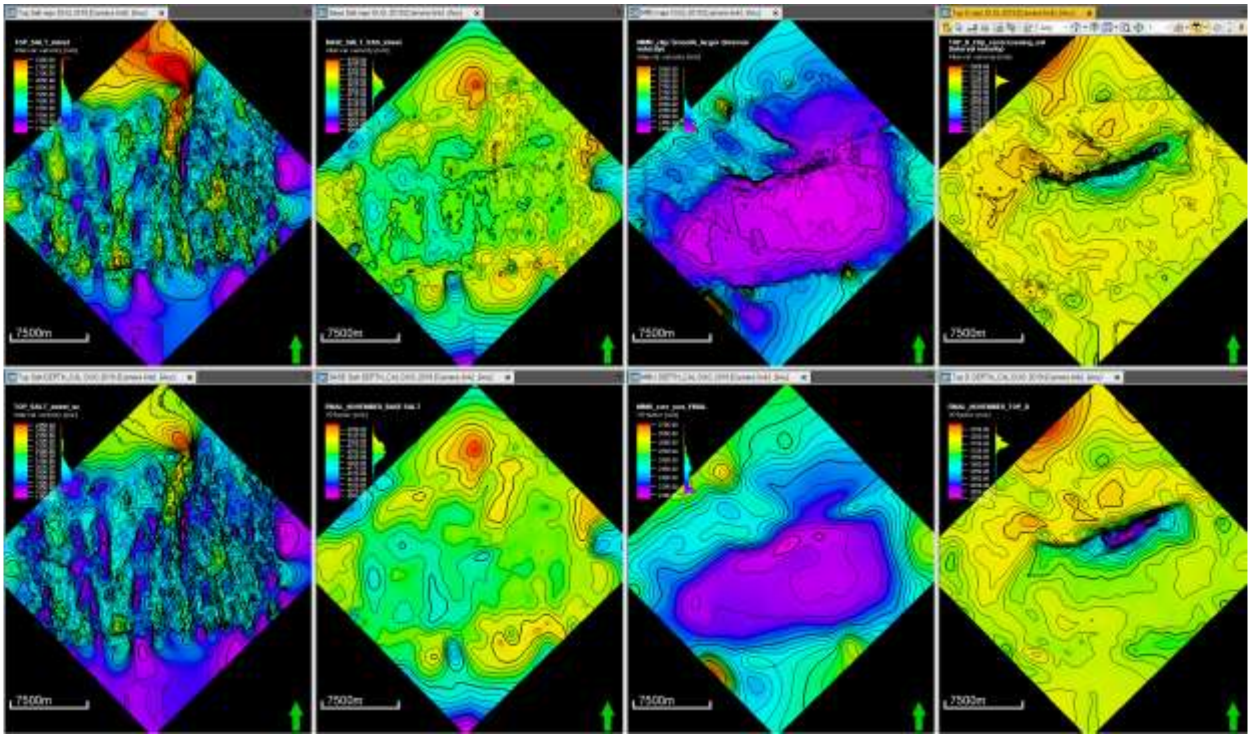


Figure 2-25 Interval velocity maps

2.6.8 Velocity model calibration QC

The velocity model followed multiple QC for clarifying the depth at well location and secure that seismic trends are followed.

In **Figure 2-26** blue is the VSP interval velocities, black is the Vp log, green is the seismic instantaneous velocities and red is the calibrated seismic instantaneous velocities.

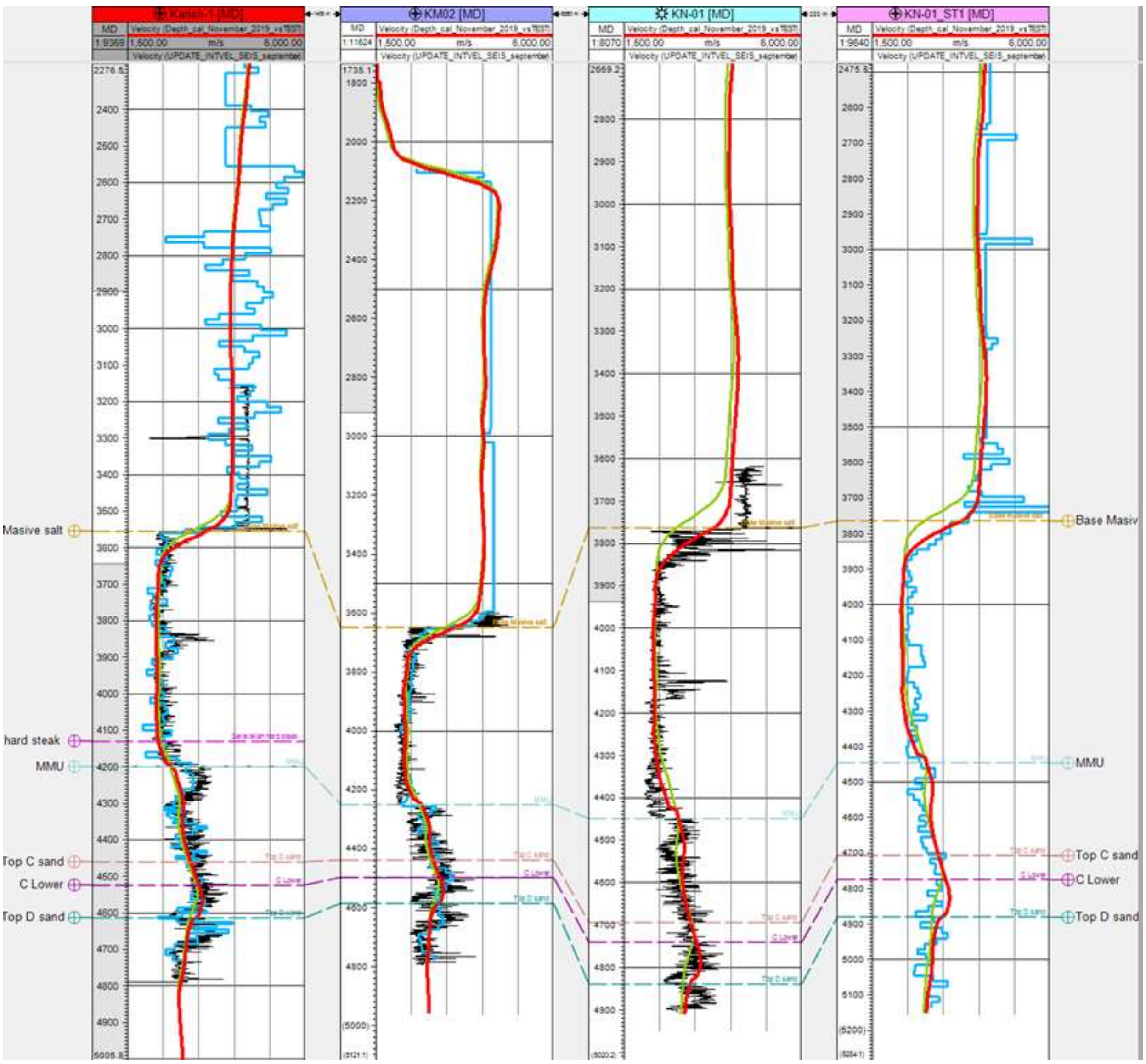
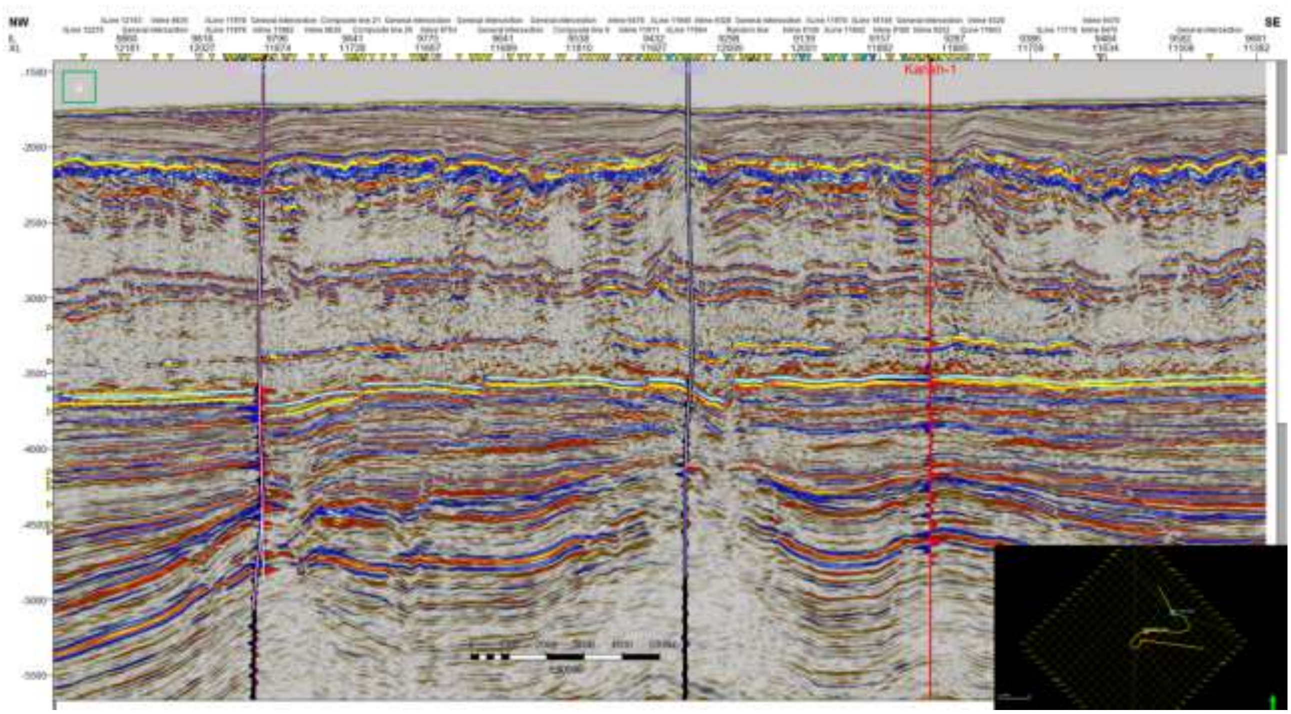


Figure 2-26 Velocity model QC

Overall the depth calibration and subsequent depth conversion was excellent, though challenging, due to the poor quality of the 3D seismic close to the ESE-NWN complex shear zone and associated fault shadow. Most wells were drilled at the crest of the Karish and Karish North fields. Wells Karish-1 and KN-01 ST03 were essential in understanding the velocity away from the crest locations since both wells were drilled on the flanks and down dip.



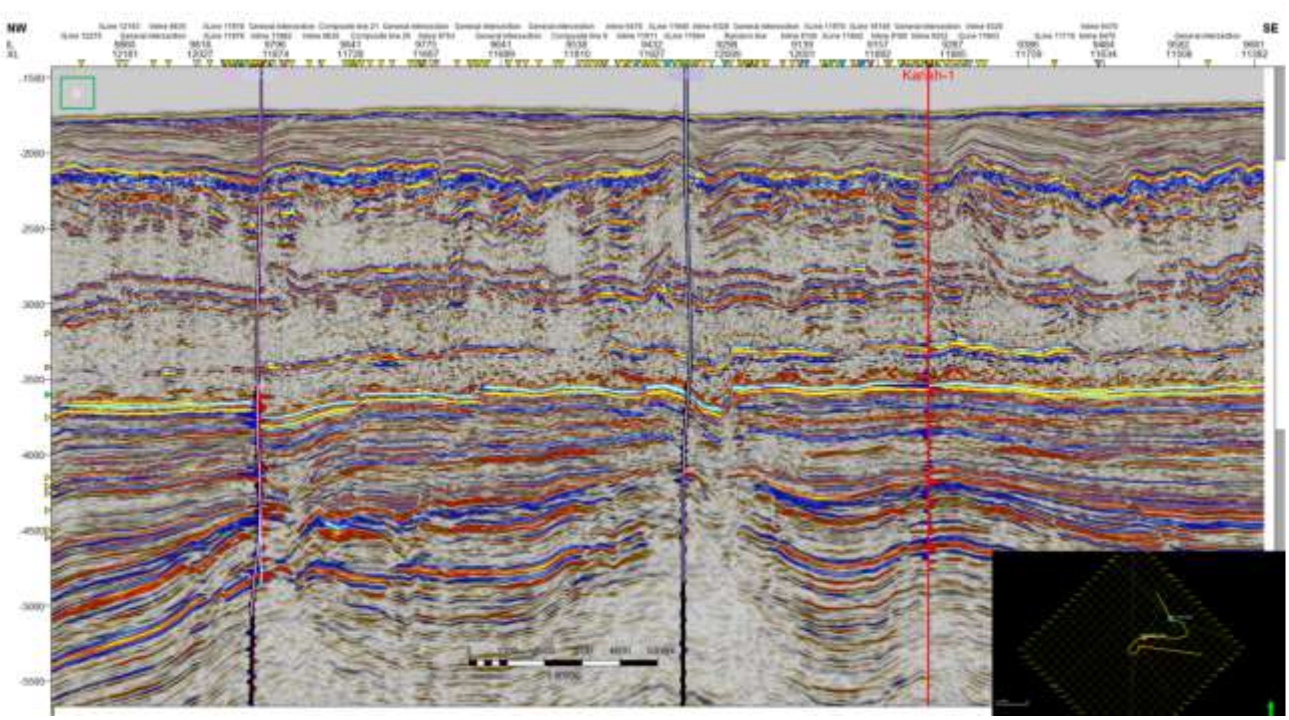


Figure 2-27 Velocity model Q, (a) original PSDM seismic, (b) calibrated PSDM seismic.

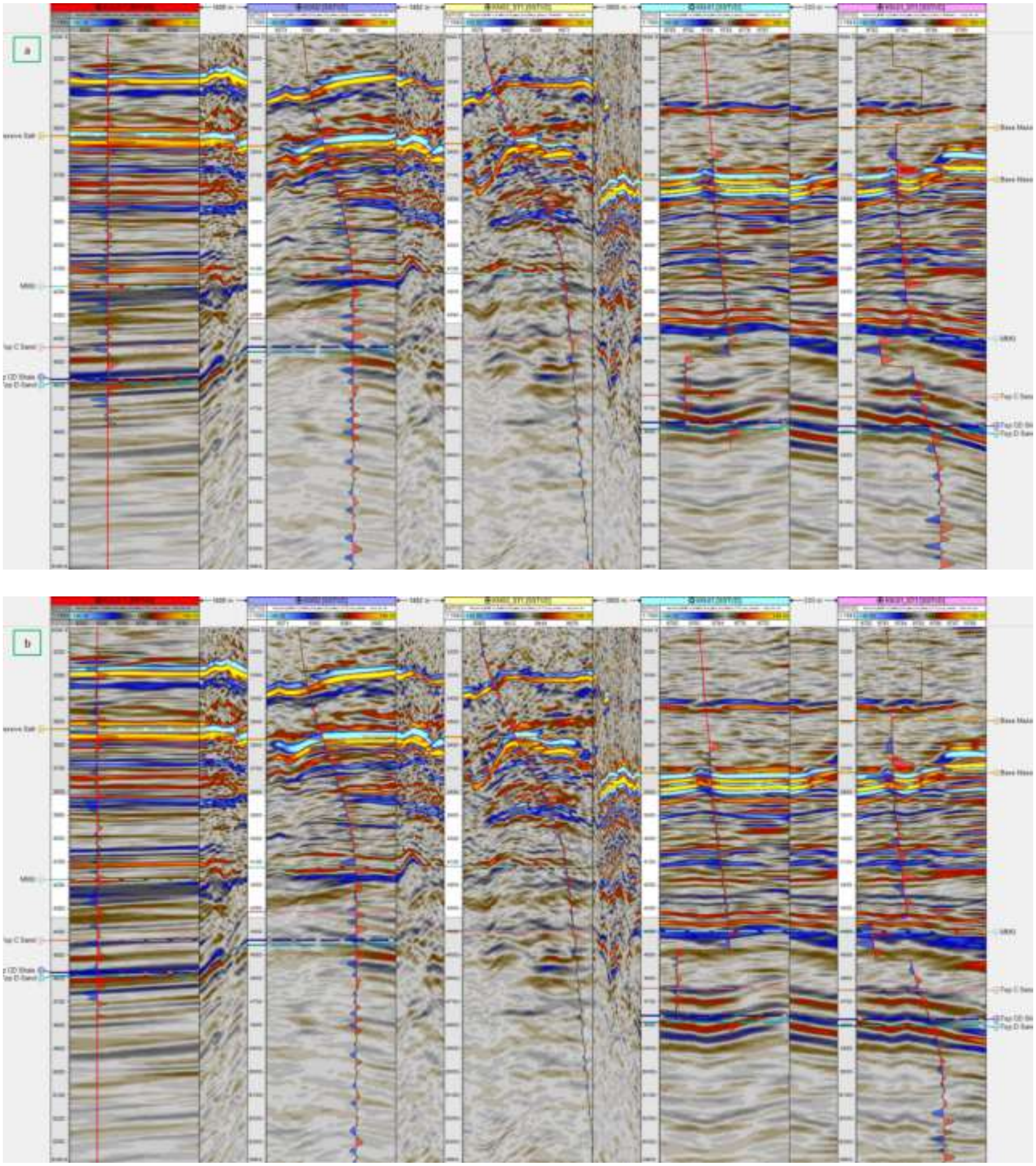
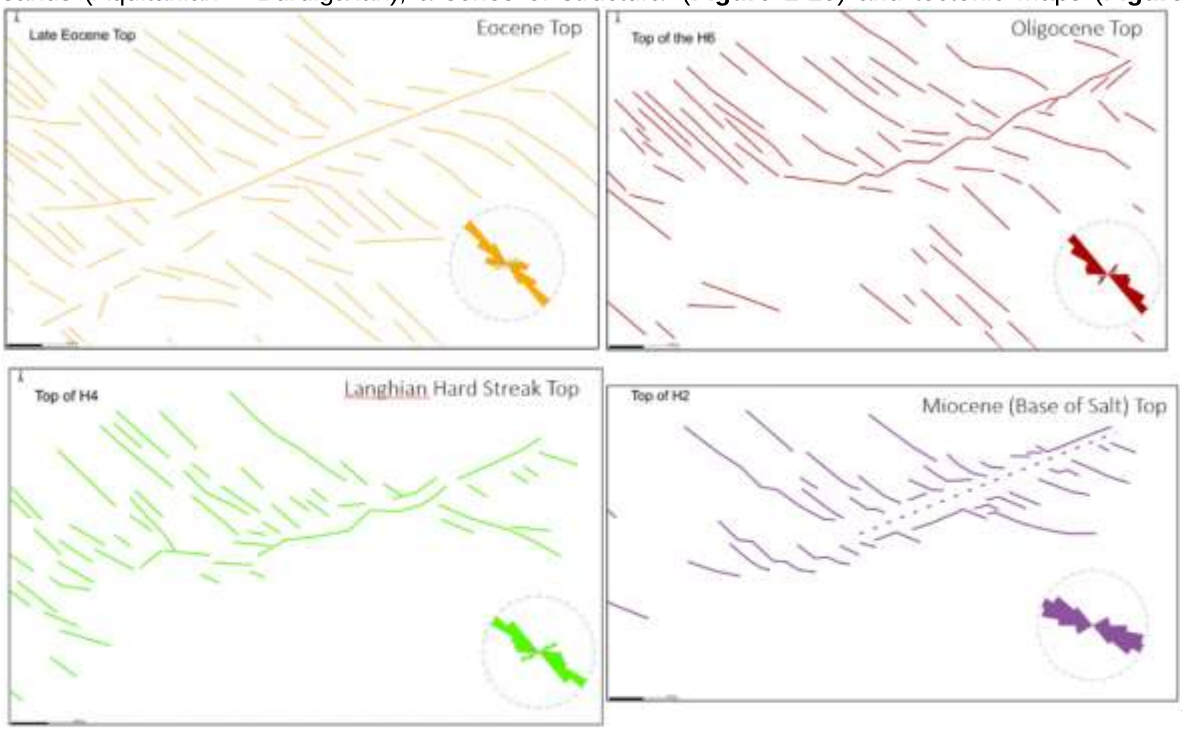


Figure 2-28 Velocity model QC. (a) original PSDM seismic, (b) calibrated PSDM seismic.

2.6.9 Tectonic Structure of the Karish Complex Gas Field

In order to understand the tectonic structure of the gas field within the depositional period of the Tamar sands (Aquitanian – Burdigalian), a series of structural (**Figure 2-29**) and tectonic maps (**Figure 2-30**



) of the overlying and underlying horizons were constructed.

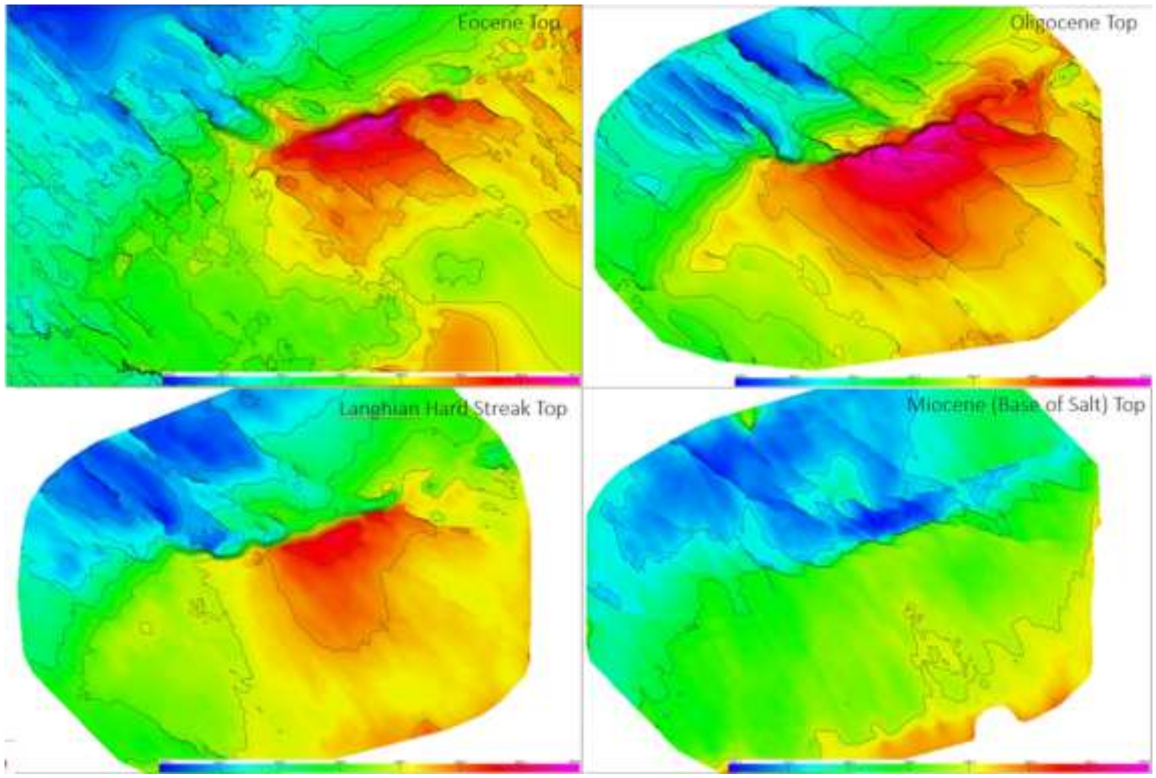


Figure 2-29 Depth structure maps of Eocene top, Oligocene top, Langhian Hard Streak top & Base of Salt top, that show the deformation of the respective horizons.

The structural and tectonic maps show that the tectonic structures of the Oligo-Miocene sedimentary sequences of the Karish complex exhibit significant variations in their spatial distribution and geometry. From the spatial extent of the brittle faulting, in the Karish complex three deformational provinces can be distinguished (**Figure 2-31**).

- The northern and eastern region (yellow polygon) with NW-SE faults cutting through the Late Miocene strata (**Figure 2-32**).
- The central region (red polygon) with ENE-WSW & ESE – WNW faults that cut through the Late Miocene strata. This zone is narrow, almost linear in map view, and is characterized by high fault intensity and we name it here the Karish Shear Zone (KSZ). Both the above regions are significant in understanding the development of the Karish North complex (**Figure 2-33**).
- The southern region (brown polygon) with NW-SE and E-W faults that are sealed by Serravalian and Tortonian strata.

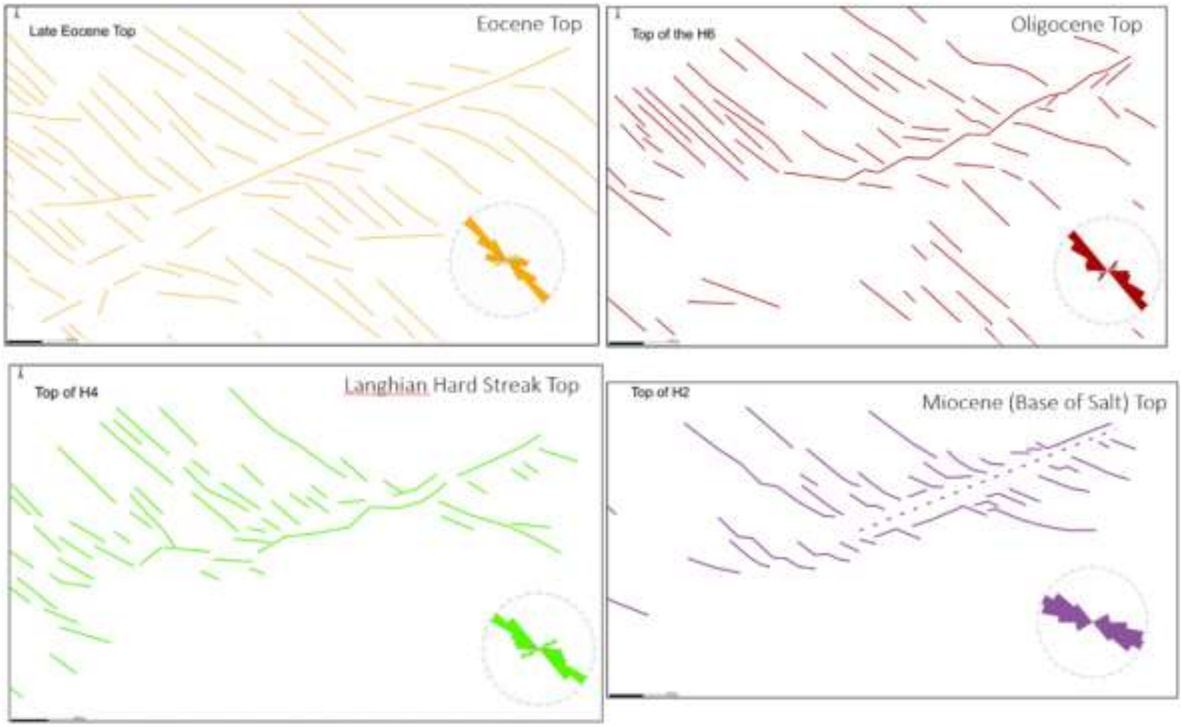


Figure 2-30 Tectonic maps of Eocene top, Oligocene top, Langhian Hard Streak top and Base of Salt top.

Figure 2-31 Superposition of the tectonic maps of Eocene top (orange), Oligocene top (red), Langhian Hard Streak top (Green) and Base of Salt top (purple) .The three tectonic provinces of the Karish Gas Field can be distinguished based on geometry.

The fact that the faults of the southern region doesn't disrupt the Middle Miocene strata while the northern ones cut through the Late Miocene ones, indicates that the northern and southern tectonic systems during their evolution were decoupled and separated by the KSZ. Thus the Karish North Gas field is part of a complex fault block with ENE-WSW oblique slip and NW-SE normal faults that developed contemporaneously in the Late Miocene. The spatial distribution of the Karish North faults as well as the shape of the second order fault blocks indicate complex fault intersections.

The structural analysis indicates that within the KSZ, complex systems of intersecting (sub-seismic) faults of ENE-WSW and ESE-WNW trend, represent R- and P- Riedel shears, connecting the NW-SE normal faults with the KSZ. Detailed mapping along the KN East Crest showed also the presence of a series of en echelon NNW-SSE faults that could probably represent R'-Riedel shears (**Figure 2-18**). Measurements of the direction of the minimum horizontal stress axis from the analysis of the NW-SE normal faults outside and within the KSZ differs only slightly (15°) and show a NE-SW direction. This direction combined with the presence of a negative flower structure along the KSZ (KN Graben) points out to a dextral transtensional zone.

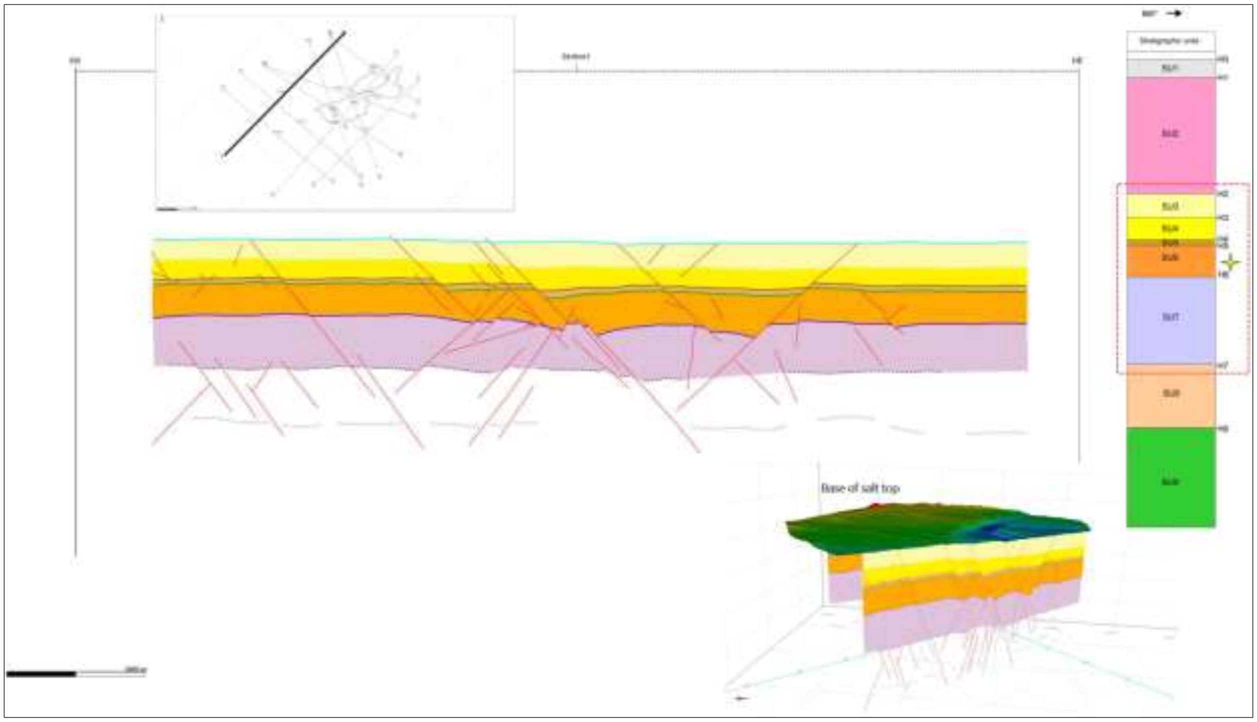


Figure 2-32 Geological cross section along the northern region of the Karish Complex showing the distribution and cross cutting relations of the NW-SE conjugate normal faults

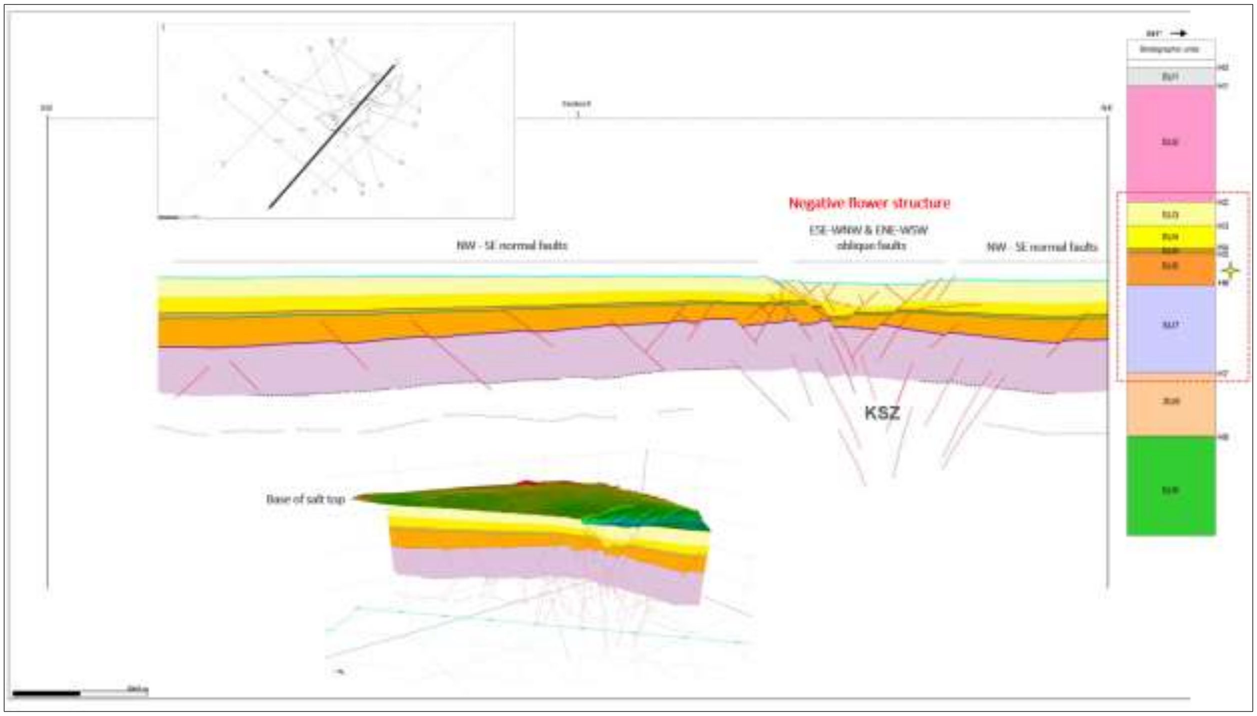


Figure 2-33 Geological cross section across the central region. The negative flower structure along the KSZ separates the Karish Main field to the SW from the Karish North field in the NE.

In order to better constrain the tectonic evolution of the Karish North within the tectonic context of the Karish Gas field a series of isopach maps were constructed. Due to the fact that isopach maps offer a simple method of showing the distribution of the thickness of individual horizons, can be used to determine the timing of folding and faulting of the sedimentary sequences. For this reason we constructed three maps (**Figure 2-34, Figure 2-35, Figure 2-36**).

The isopach map of the Oligocene (**Figure 2-34**) doesn't show thickness changes in the area of the Karish North This indicates tectonic quiescence in this area during the Oligocene. On the other hand the isopach map of the Aquitanian – Langhian (**Figure 2-35**) show significant changes in the thickness of strata, indicating that Early and Middle Miocene was a period of intense deformation in the Karish North. The observed syn-depositional thickness variations, especially in the upper parts of the Vourdigalian strata, point out to the presence of an asymmetric NE-SW trending monoclonal fold, along the crest of which the thickness of the Late Vourdigalian successions are greatly reduced.
The isopach map of the Serravallian – Messinian (**Figure 2-36**) show also spatial changes in thickness along the Karish North. The observed syn-depositional thickness are restricted to the south (in the area of the Karish North Graben) and are absent to north while the boundary of the major thickness change is the KSZ..

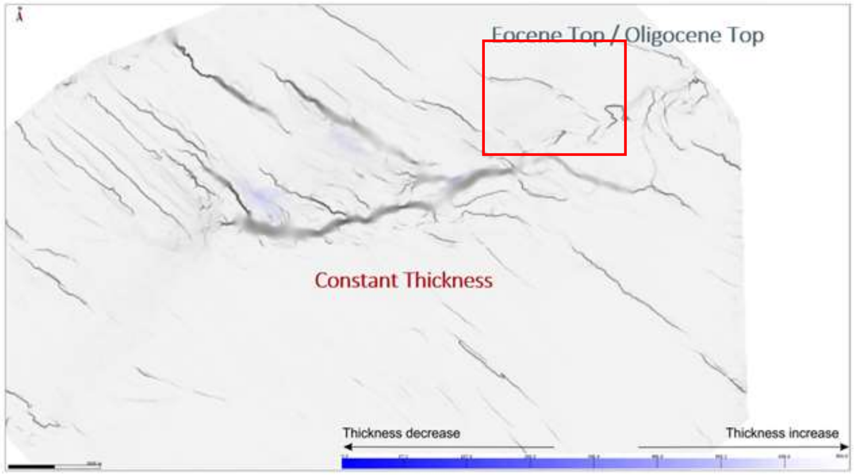


Figure 2-34 Isopach map of the Oligocene.

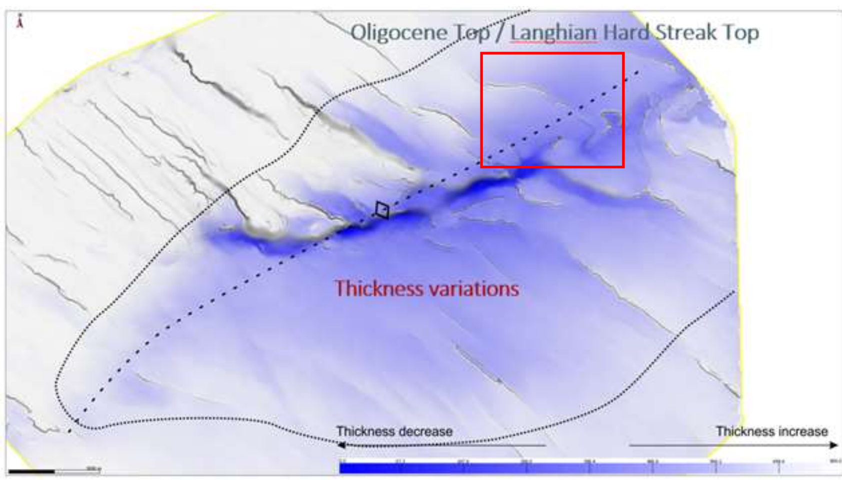


Figure 2-35 Isopach map of the Aquitanian - Langhian.

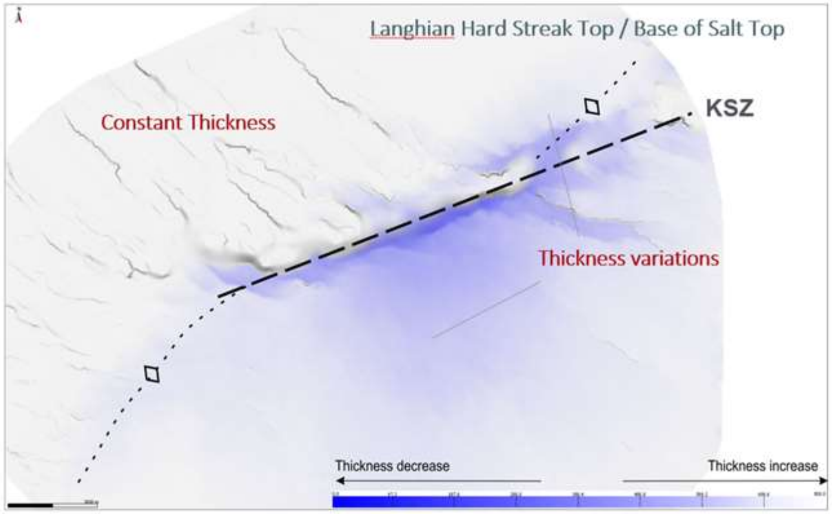


Figure 2-36 Isopach map of the Serravallian – Messinian.

The structural analysis implies that the tectonic structures observed within the Karish Field exhibit several changes in their development that are gradual but can be tentatively grouped into two periods of tectonic deformation: (1) an initial period of convergent deformation during Early Miocene, and (2) a second period of strike-slip faulting during Middle-Late Miocene (**Figure 2-37**).

During Early Miocene (mainly Late Vourdigalian) the Oligocene and Aquitanian-Early Vourdigalian sediments were folded in NE-SW direction. Coeval with folding a series of NW-SE conjugate normal faults started to form (like tension gashes) (Figure 2-35 top map). During Langhian – Serravalian the KSZ started to initiate and decoupled the tectonic systems north and south of it, deactivating the southern ones (Figure 2-35-middle map). Continuous displacement along the KSZ during Late Miocene led to the development of an ENE-WSW graben that currently separates the Karish Main field from the Karish North field (Figure 2-35 bottom map).

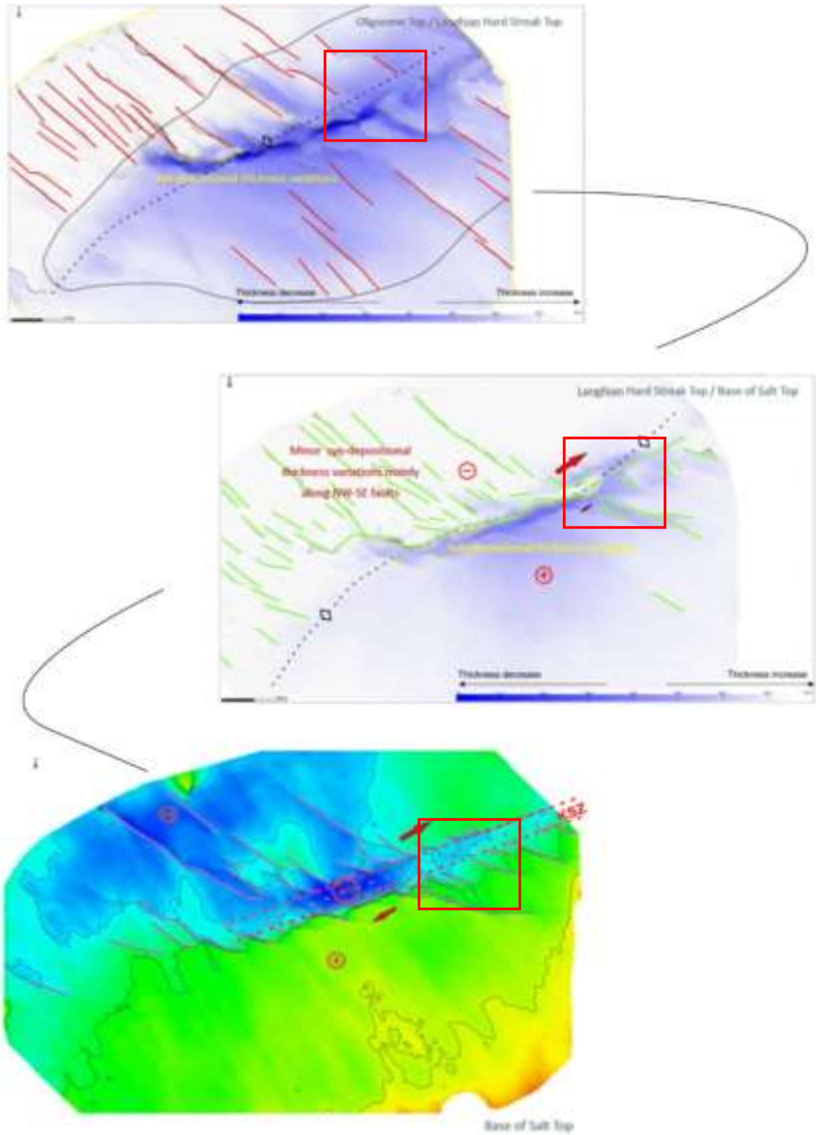


Figure 2-37 Proposed tectonic evolution of the Karish Gas field

3 Petrophysics

3.1 Summary

A full petrophysical interpretation of the Karish North 01 and sidetracks was carried out in Q4 2019 by Energean, this consisted of:

- Collation of relevant information.
- Input and merging of all available data.

- Quality check and curve editing including, but not restricted to, merging, depth matching and despiking
- Performance of environmental, “bad hole” and invasion corrections as required.
- Determination of a realistic interpretation model by utilising a variety of cross plotting techniques and researching the available data.
- Determination of lithology, porosity, fluid saturations and net/gross.
- Calibration of interpretation to the available core

The petrophysical analysis was conducted to generate CPIs for incorporation into the geological model and volumetric analysis. A simple, consistent deterministic total porosity petrophysical model was applied, utilising all data collected in the main borehole and the subsequent sidetrack locations.

3.2 Karish North Petrophysical Data Overview

Karish North 01 has the benefit of a full wireline suite, LWD triple combo data, bottomhole fluid samples and pressure, as well as a 27m core taken in the Upper C sand. The full list of logs acquired are given in

KARISH NORTH 01			
Run No	**Services**	**Start Depth (mMDBRT)**	**End Depth (m)**
1A	RWCH-7C-GTET-AST-XRMI	4912	3653
1B	RWCH-7C-GTET-CSNG-DSNT-SDLT-SP-Sub-ALAT- MSFL	4900	3650
1C	RWCH-7C-D4TG-MRIL-XL	4900	4867
1D	RWCH-7C-D4TG-QGS-HPS-DPS1-DPS-QGS-FPS-FLID-MCS-MCS (RDT Tool)	4842	4630.9

Table 3-1 & **Table 3-2**, LWD triple combo data was also acquired. No core was attempted.

KARISH NORTH 01			
Run No	**Services**	**Start Depth (mMDBRT)**	**End Depth (m)**
1A	RWCH-7C-GTET-AST-XRMI	4912	3653
1B	RWCH-7C-GTET-CSNG-DSNT-SDLT-SP-Sub-ALAT- MSFL	4900	3650
1C	RWCH-7C-D4TG-MRIL-XL	4900	4867

1D	RWCH-7C-D4TG-QGS-HPS-DPS1-DPS-QGS-FPS-FLID-MCS-MCS (RDT Tool)	4842	4630.9

Table 3-1 – Karish North 01 Wireline Runs

KARISH NORTH 01 ST01			
Run No	**Services**	**Start Depth (mMDBRT)**	**End Depth (m)**
1A	RWCH-7C-D4TG-HPS-DPS1-QGS-FPS-FLID-MCS- MCS (RDT Tool)	5160	4336
1B	DCU-G-Gun (VSP)	5135	2085
1C	RWCH-7C-D4TG-MRIL-XL	5149	4550

Table 3-2 – Karish North 01 ST01 Wireline Runs

Logging while drilling (LWD) was performed in KN01 and KN01 ST01. This data was also uploaded to IP to be included in the analysis including the Halliburton dual gamma ray tool (DGR), high frequency induction resistivity tool (EWR-4), density tool (ALD) and a compensated thermal neutron tool (CTN). In addition to providing real time density and photo-electric cross section (PEF) data; data from the ALD (Azimuthal Litho Density) tool could be processed to derive basic images for bed definition and dip calculation.

The LWD data was acquired, not only to provide an insurance dataset (in addition to wireline), but also to provide a direct comparison of LWD data to wireline. This comparison provides a useful benchmark for future wells in Energean's Israeli portfolio, where LWD tools maybe the only data acquisition mode available due to borehole trajectory.

All data acquired in KN01 ST02 was on LWD, being limited to Gamma Ray and Resistivity only, with the well failing to reach the Tamar Sandstone Member reservoir. KN01 ST02 is therefore excluded from the petrophysical analysis.

All data acquired in KN01 ST03 was on LWD, being limited to Gamma Ray, Resistivity and Formation Pressures. The LWD logs have therefore been excluded from the petrophysical analysis. The formation pressures and resisitivity have been used to define the FWL, and the Gamma Ray has been used to correlate to the crestal KN01 well. Given the excellent correlation between KN01 and KN01ST03, the petrophysical properties of the KN01 well are entirely relevant/applicable to the KN01 ST03 flank well.

All the wells drilled on the Karish North structure encountered a similar stratigraphic column, with thin gas bearing sands being intersected at the B Sand level, underlain by a high NTG, massive gas bearing Upper C Sand interval and interbedded Lower C Sand member. The D sand was water bearing in all wells, but this stratigraphic unit is expected to be gas bearing in the Karish North crest.

LWD GeoTap formation pressure data in KN01 ST03 confirmed a FWL/GWC at a depth of 4791 mTVDSS

3.3 Petrophysical Analysis

Wireline along with additional pertinent supporting data, where available, was loaded into Interactive Petrophysics (IP) petrophysical platform. The analyses have been performed using the original wireline depth measurement control. In all cases, the first wireline run in the hole formed the depth reference against which all other data were referenced. The wireline data is the primary formation evaluation data used as inputs to the CPIs.

A 5 ¼ " core was also acquired across the Upper C Sand in KN01. The cores were shipped back to the UK for analysis at Stratum Laboratories, East Grinstead, UK, where initially routine core analysis (RCA) measurements were undertaken. The RCA data consisted of base permeability measurements, both horizontal and vertical, made at 400 psi confining pressure; helium porosity measured at ambient conditions, as well as grain density and fluid saturation measurements via the Dean and Stark method. The mud system was spiked with deuterium, which allowed the resultant Dean and Stark water saturation to be corrected for invasion. A Special Core Analysis Programme (SCAL) has also been commissioned, with analysis ongoing at the time of writing this FDP and its results will be incorporated once available.

3.4 Methodology

3.4.1 Volume of Clay

At the time of preparing this FDP addendum, sedimentological and petrographical information was not available to assist with the determination of volume of clay (VCL). Provisional data from the special core analysis was available and has been used to select the clay and sand points from the zonal histograms of the gamma ray data. The resultant VCL calculated was visually compared to the mudlog and the composite log for completeness. For this analysis, an average of the linear gamma ray and the neutron density VCL models, was used (see **Figure 3-1**)

3.4.2 Porosity

Both total porosity and effective porosity were calculated using the density porosity module within IP, which initially calculates a shale and hydrocarbon corrected effective porosity, then backs out a total porosity from the volume of clay calculated above. On review of the conventional core analysis data, a matrix density of 2.655 g/cc was used. For fluid density, IP interactively calculates an apparent fluid density from the mud density and hydrocarbon density estimated from the RDT operations, using the shallow reading laterolog as an estimate of the fluid zone saturation. For KN01 ST01, no shallow reading LWD was acquired and the flushed zone saturation was estimated using an invasion factor calculation within IP. To compare the log porosity to core porosity, a single 0.94 reduction to the core porosity data has been used. The comparison at this stage of the analysis appears reasonable (see **Figure 3-2**)

3.4.3 Water Saturation

Total porosity calculated from the method outlined above was used to calculate total water saturation, using the Archie water saturation equation. Once the special core analysis data has been acquired, especially the excess conductivity, as well as the cementation exponent (m) and resistivity index data (n), more complex saturation equations will be evaluated along with sensitivities on parameter value evaluated. The log based Archie water saturation compares reasonably when compared to the Dean and Stark invasion corrected core water saturations.

3.4.4 Reservoir Temperature (Rw)

Bottom hole temperature (BHT) is usually estimated from static Horner style plots derived from the various wireline runs. Due to difficulty in operations in both the KN01 and the limited wireline runs in KN01 ST01, this was not possible. During RDT pre-test and sampling operations, flow line temperatures are also measured. All data was then used to generate an estimate of formation temperature profile using a standard surface temperature and the corrected bottom hole temperature. For KN01 a sea bed temperature of 14 degC and a temperature of 71.1 degC at 4850 m TVDSS was used to create a temperature profile throughout the well. For KN01 ST01 at TD (5150 m TVDSS), the estimated bottom hole temperature was 78.3 degC. This data compared favourably with the RDT pre-test and sample temperatures.

3.4.5 True Formation Resistivity (RT)

For KN01 the wireline array laterolog data was acquired in the well. The deepest reading array, RA5, was used as true formation resistivity in this well.

For KN01 ST01 only LWD phase EWR resistivity was available. In this well the deep reading R39PC curve, which is the borehole corrected 39" phase resistivity curve, was used as true formation resistivity.

3.4.6 Formation Water Salinity

The formation water salinity derived from the previous analysis of downhole water samples from the Karish-1 well was adopted for the analysis in KN01. This indicated a salinity of 28,000ppm, giving a Rw of 0.268 ohmms@ 15.6degC. Water samples were recovered during the RDT operations in KN01 and KN01 ST01, but all had some degree of contamination by water based mud. These samples could not therefore be used to derive an accurate formation water salinity. Consideration will be given in future wells to attempt to acquire a clean formation water sample.

3.4.7 Saturation and Cementation Exponents

Whilst awating final delivery of the SCAL data, it was decided to use the following standard saturation and cementation exponents, a=1.0, m=1.8 and n=2.0 for the main reservoir zones of interest. Once the SCAL data has been finalised these values will be altered to reflect these core derived values.

3.4.8 Net to Gross

For this analysis, a standard set of net cut-offs were universally adopted.

Initially, net rock was defined by the application of a 40% (0.4) Vcl cut-off., this was applied to differentiate sand rich layers against non-reservoir shale/clay/silt dominate layers, which could be defined as potential reservoir, notwithstanding non-reservoir cemented zones elsewhere in the field.

To define the net potential reservoir, porosity cut-offs were applied to the net rock values. For all sections a porosity (PHIT) cut-off of 10% (0.1p.u.) was used. In addition, to define net pay sections a simple 60% (0.6 p.u.) water saturation value was used. These cut-offs are considered conservative for a gas filled reservoir.

A cut-off sensitivity analysis was performed using variable VCL and porosity cut-offs. These can be found in **Figure 3-1** and **Figure 3-2**. These plots illustrate how each cut-off, VCL and PHIT, affect the net reservoir calculated. It is clear that the Lower C Sand is very sensitive to the various cut-off values, especially VCL, yet in contrast the Upper C Sand is relatively insensitive to both VCL and PHIT cut-offs. This is a function of thin beds and multiple bed boundary effects. Further work is being considered, namely, using the resistivity image, coupled with core sedimentology to better define net and non-net sections, especially over the more interbedded sections in the well. It is expected that this work will be performed in Q2 2020.

Figure 3-1 – Sensitivity of Net Pay/Reservoir to VCL Cut-Off for KN01

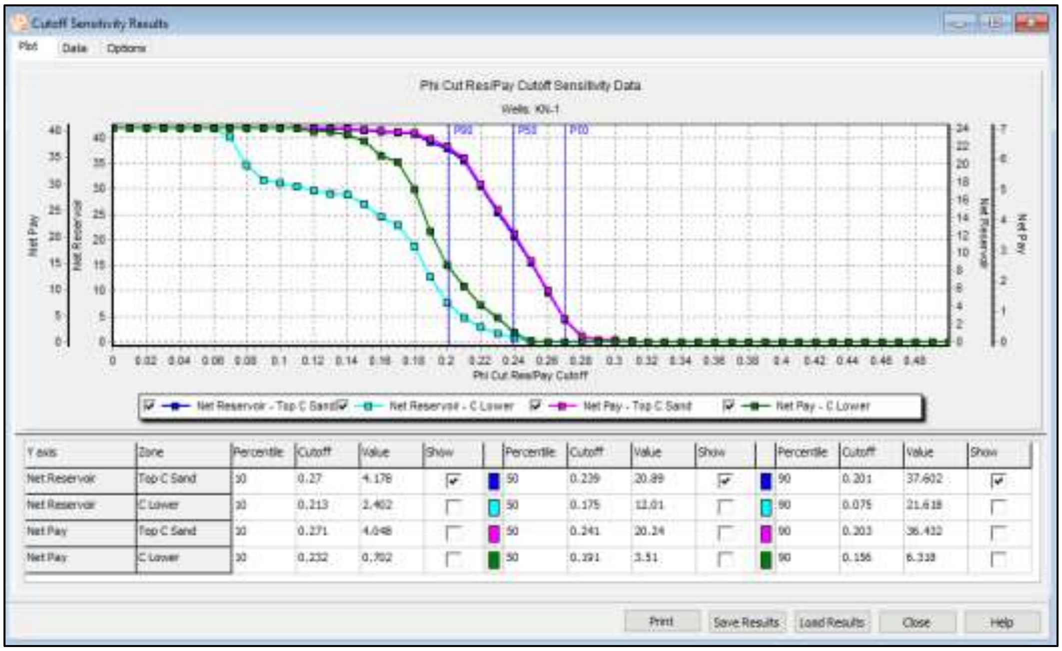


Figure 3-2 – Sensitivity of Net Pay/Reservoir to PHIT Cut-Off for KN01

3.4.9 Permeability

The routine core analysis (RCA) for KN01, as well as short cores taken in KM01 and KM02, were used to generate a simple K/PHI transform as illustrated in **Figure 3-3**, with the following exponential equation generated

$$\textbf{Log PERMEABILITY} = \mathbf{0.0029exp^{(0.5349*PHIT)}}$$

Where: PHIT is in percent and the resultant permeability value is in milliDarcies.

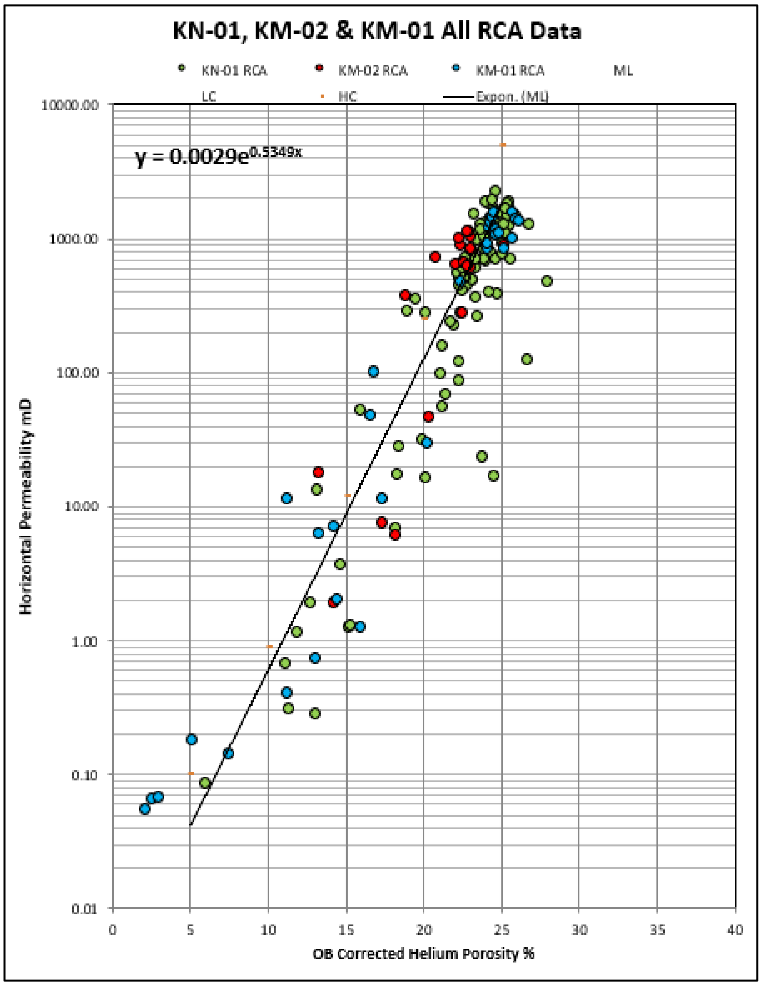


Figure 3-3 – Porosity Permeability Cross Plot Based on KN01 Routine Core Analysis

It is considered that the permeability calculated using the simple equation above when compared to other permeability, e.g. from the nuclear magnetic resonance log after light hydrocarbon correction, is reasonable. Once the sedimentological and SCAL data has been integrated, a further review of the permeability transform, including corrections for overburden and fluid type will be addressed and applied accordingly. The resultant data from the equation above is averaged both arithmetically as well as geometrically in the petrophysical summation tables **Table 3-3** and **Table 3-6**.

3.5 Karish North 01: Petrophysical Analysis Results

3.5.1 A Sands

Petrophysical analysis indicates that the A Sand section is primarily shale prone with no net sand identified over this interval. Mudlogging descriptions and XRMI analysis indicate that they may be thin silty sections over this interval along with thin limestones, especially over the uppermost A Sand interval, which are identified by the background gas increasing slightly.

3.5.2 B Sands

The B Sand interval (**Figure 3-4**) is also shale prone, but with three thin gas bearing, good reservoir quality sands, identified in this section. The first two of these sand intervals were contained over the interval 4625-4640 m MDBRT, whilst the third occurred just above the main Karish C Sand interval between approximately 4676-4678 m MDBRT.

The overall NTG (Reservoir) for the B Sand section was 0.092, whilst the NTG (pay) was much lower at 0.023. This reflects the overall shale prone lithology and the thinly bedded nature of the sand sections, which causes water saturations to be affected by thin bed issues supressing the resistivity. This causes excessively high water saturation being calculated. Over the net interval, the average porosity was calculated to be 18.1% (Res) and 24.3% (Pay), again showing the effect of thin bed issues. The limitations of conventional petrophysics have been overcome by analysis of the XRMI image data to generate low-mid-high case reservoir sand flags. This work was performed by Task Fronterra (2019) and is available as a separate report.

For the B sands and Lower C sands, the log based water saturation values, as previously outlined, are affected by thin bed/bed boundary issues and do not represent true water saturations for rock of this reservoir quality. It is envisaged that over the pay section, saturations should be in the order of 10-20%, rather than the average of 40% as calculated from the NTG criteria, because the resistivity is being suppressed due to shoulder effects on the thin beds, resulting in higher log derived water saturation. This is also supported by the Mercury Injection Capillary Pressure (MICP) data available from Karish North 01 (see Section 4.5.7**Error! Reference source not found.**)

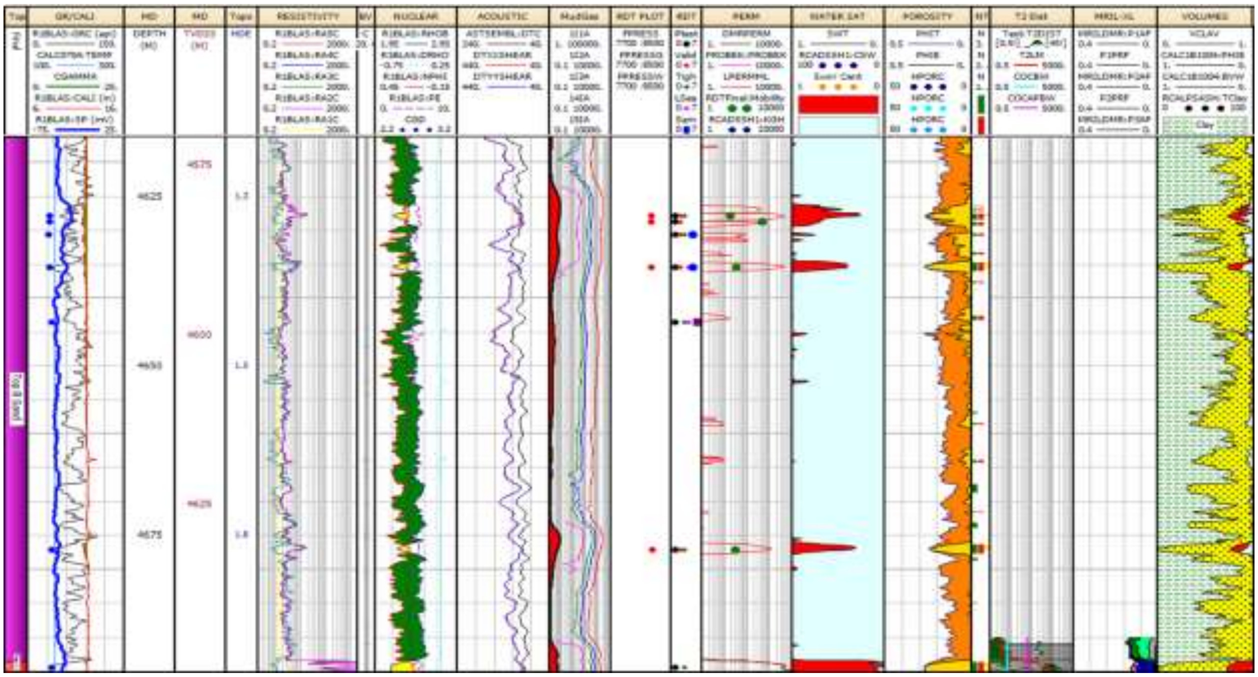


Figure 3-4 – KN01 B Sand Petrophysical Summary Plot

3.5.3 C Sands

The Upper C Sand (**Figure 3-5**) is a high NTG sandstone with excellent reservoir properties(), which is consistent across all data sources. The section is dominated by thick sandstones with excellent reservoir quality, with minor thin shale interbeds. The NTG (Res) is calculated to be 0.899, whilst over the NTG (Pay) the value is 0.870. The porosity over the reservoir and pay are very similar, around 23.7%, whilst the average Sw over the pay section is calculated to be 20.9%. The overburden corrected core porosity to log porosity comparison is favourable, as is the comparison between core derived water saturation and the log derive water saturation especially over the thicker sand sections.

Once the final KN01 SCAL data has been acquired, a more robust calculation of water saturation including a saturation height function that takes into consideration all the capillary pressure data will be derived.

The Lower C Sand (**Figure 3-6**) is a highly interbedded sandstone/siltstone/shale section, which is totally gas bearing. Where there are sandstones present the reservoir quality is considered to be good. The NTG (Reservoir) has been calculated to be 0.251, while the NTG (Pay) is calculated to be 0.099. Porosity values average 18.3% over the NTG (Reservoir) and 19.3% over the NTG (Pay). In addition, the average water saturation over the NTG (pay) is 43.9%. As all RDT pressure points across this section fall on a gas gradient, it is considered that the average water saturation does not reflect the true water saturation in the sands in this section. Once the image data is integrated into the petrophysical analysis then NTG will increase. In addition, once resistivity suppression caused by thin bed/ bed boundary effects is taken into account, it is anticipated that the average water saturation will increase to a value in the 20-25% range. The reservoir quality in the Lower C Sands is marginally lower than that of the Upper C Sands.

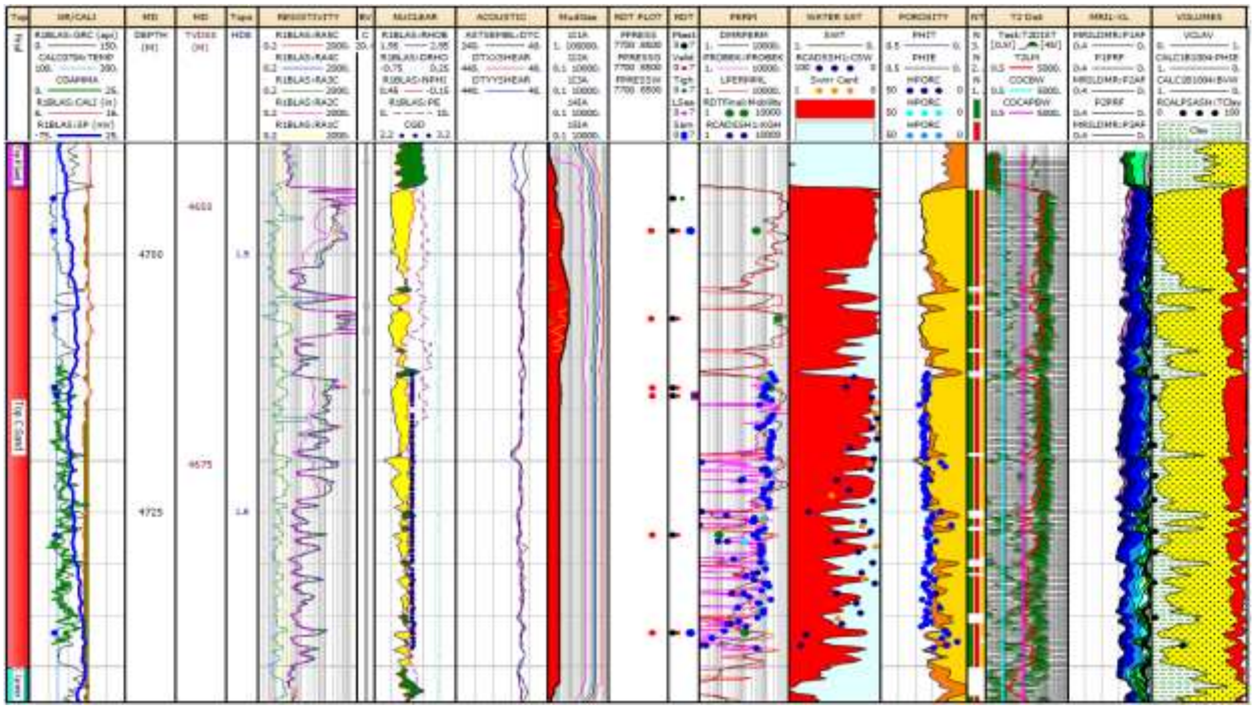


Figure 3-5 – KN01 Upper C Sand Petrophysical Summary Plot

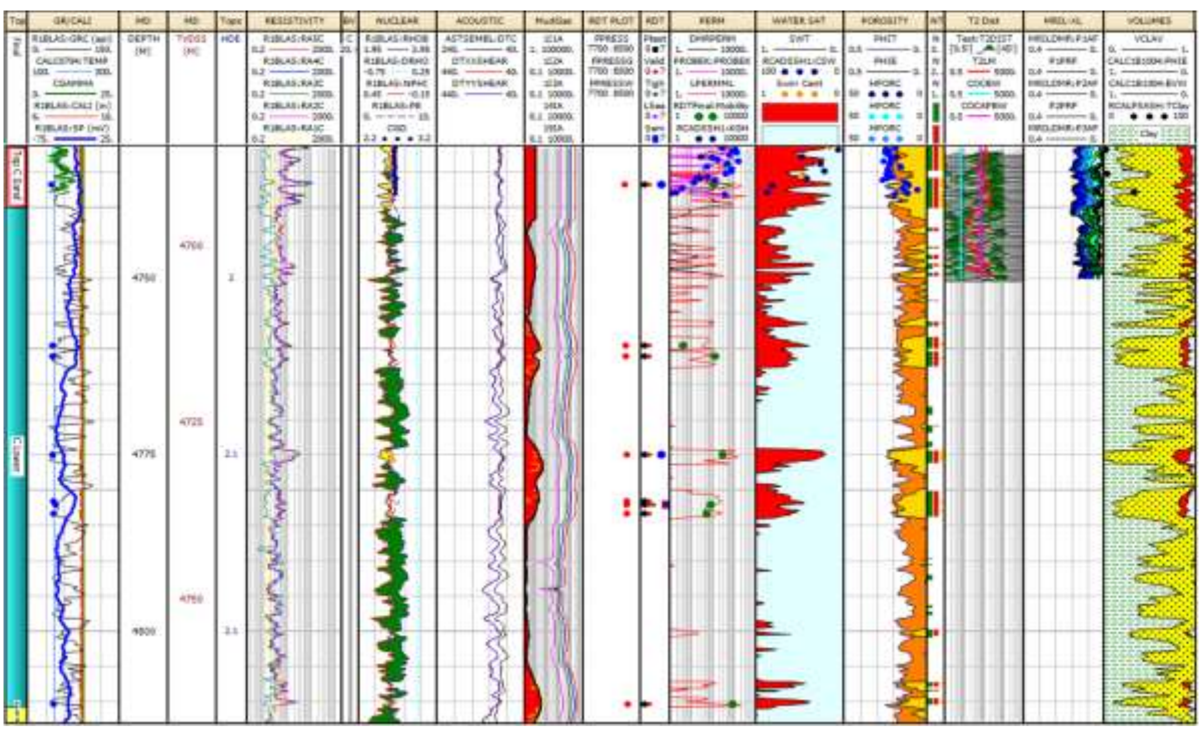


Figure 3-6 – KN01 Lower C Sand Petrophysical Summary Plot

3.5.4 CD Shale and D Sands

The CD shale divides the Lower C Sands from the D Sand interval.

The CD Shale (**Figure 3-7**) is predominantly a shale section. In KN01 a 3 m thick, gas bearing sandstone is present, which it situated towards the top of the CD Shale interval,. The sandstone has moderate to good reservoir quality and looks to be totally gas filled. A gas sample was taken in this bed at 4818 m MDBRT (4772.5m ss). The NTG (Reservoir) for the CD Shale was calculated to be 0.091, whilst the NTG (pay) is 0.057, which are both found entirely in this thin sand. The porosity averages 20.6% over the NTG (reservoir) and 19.3% over the NTG (pay). The water saturation averages 48.6% over the NTG (pay). Evidenced by a clean gas sample which was acquired at the base of this sand, these values indicate that the section is suffering from thin bed/bed boundary resistivity suppression. This results in too high a log calculated water saturation. A value closer to 20-25% would be a better average for water saturation in this bed.

The D Sand at the KN01 location is exclusively below the Karish North Field GWC (4791m TVDSS), and is primarily an interbedded shale/siltstone/sandstone section with a NTG (Res) of 0.373, with an average porosity of 17.8%. (**Figure 3-7**).The section is entirely water bearing and a water sample was recovered from a thin sandstone towards the top of the D Sand at 4842 m MDRKB (4696.5 m SS).

The D2 Sand below is partially penetrated in the KN01 well (see CPI Figure 9). The well only penetrates the upper, 50 m or so of the D2 Sand, with a full coverage of wireline data only available for the up 15 m or so, of this section. The section again is an interbedded sandstone/siltstone/shale section, with an NTG of 0.081 and an average porosity of 18.0% over the upper interval. The section is totally water bearing, as confirmed by the RDT pre-test pressures.

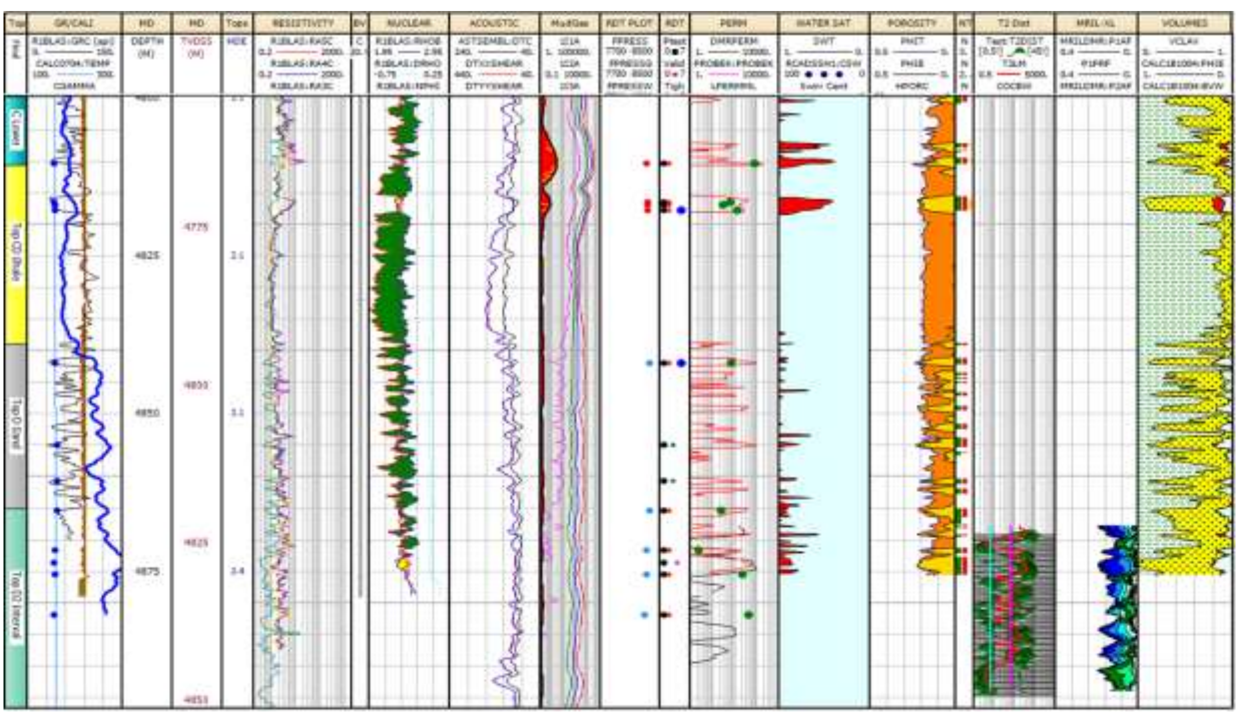


Figure 3-7 – KN01 CD Shale/D Sand Petrophysical Summary Plot

Reservoir Summary

Zn #	Zone Name	Top m	Bottom m	Gross m	Net m	N/G	Av Phi	Av Sw	Av Vcl Ari	Av PERM(A) Ari	Av PERM(G) Geo	Phi*H	PhiSo*H
1	B Sand	4577.71	4693.58	115.87	10.70	0.092	0.181	0.723	0.250	557.47	45.80	1.93	0.54
2	Upper C Sand	4693.58	4740.03	46.45	41.78	0.899	0.237	0.220	0.140	1772.62	870.90	9.90	7.72
3	Lower C Sand	4740.03	4810.70	70.67	17.82	0.252	0.183	0.597	0.218	154.12	52.48	3.27	1.32
4	CD Shale	4810.70	4838.93	28.23	2.58	0.091	0.206	0.607	0.134	210.08	177.86	0.53	0.21
5	D Sand	4838.93	4865.10	26.17	9.77	0.373	0.178	0.996	0.244	158.14	39.70	1.74	0.01
6	D2 Interval	4865.10	4950.00	84.90	6.85	0.081	0.180	0.975	0.210	140.76	43.13	1.23	0.03
	All Zones	4577.71	4950.00	372.29	89.50	0.240	0.208	0.472	0.185	958.91	435.23	18.60	9.82

Pay Summary

Zn #	Zone Name	Top m	Bottom m	Gross m	Net m	N/G	Av Phi	Av Sw	Av Vcl Ari	Av PERM(A) Ari	Av PERM(G) Geo	Phi*H	PhiSo*H
1	B Sand	4577.71	4693.58	115.87	2.70	0.023	0.243	0.404	0.080	1919.50	1263.08	0.66	0.39
2	Upper C Sand	4693.58	4740.03	46.45	40.48	0.871	0.238	0.209	0.135	1820.34	937.55	9.65	7.63
3	Lower C Sand	4740.03	4810.70	70.67	7.02	0.099	0.193	0.439	0.145	225.58	86.96	1.35	0.76
4	CD Shale	4810.70	4838.93	28.23	1.60	0.057	0.212	0.486	0.083	254.09	244.15	0.34	0.17
5	D Sand	4838.93	4865.10	26.17	0.00	0.000	---	---	---	---	---	---	---
6	D2 Interval	4865.10	4950.00	84.90	0.00	0.000	---	---	---	---	---	---	---
	All Zones	4577.71	4950.00	372.29	51.80	0.139	0.232	0.253	0.132	1561.00	817.83	11.99	8.96

Table 3-3 – Petrophysical Layer Averaged Analysis Results and Summation for KN01

	Zone 1: Upper	Zone 2: Middle Shale	Zone 3: Lower Shale	Zone 4: B Sand	Zone 5: C Sand	Zone 6: Lower C Sand	Zone 7: CD Shale	Zone 8: D Sand
Top m TVDSS	3500	3831.2	3936.6	4583.7	4693.5	4740.8	4817.8	4835.9
Base mTVDSS	3831.2	3936.6	4583.7	4693.5	4740.8	4817.8	4835.9	4908.3
GR Use	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes
GR Method	Linear	Linear	Linear	Linear	Linear	Linear	Linear	Linear
ND Den Clay	2.35	2.4	2.4	2.4	2.4	2.35	2.35	2.4
ND Neu Clean1	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04
Vcl Av Method	Mean	Mean	Mean	Mean	Mean	Mean	Mean	Mean
Percentile Clean	10.04	17.96	14.93	17.96	10.84	14.93	12.39	14.93
Clip Low %	0	0	0	0	0	0	0	0
GR Clean	20	50	45	50	33	45	40	45
ND Use	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
ND Den Clean1	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65
ND Den Clean2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Vcl Mix Method	Minimum	Minimum	Minimum	Minimum	Minimum	Minimum	Minimum	Minimum
Percentile Clay	96.8	96.8	84.7	84.7	99.7	99.7	104.1	96.8
Clip High %	98	98	98	98	98	98	98	98
GR Clay	100	100	90	90	105	105	110	100
ND Neu Clay	0.35	0.4	0.4	0.45	0.45	0.4	0.35	0.4
ND Den Clean2	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05
Link PhiSw Clay	No	No	No	No	No	No	No	No
Use Percentile	No	No	No	No	No	No	No	No
Percentile Group	1	1	1	1	1	1	1	1
Steiber Constant	2	2	2	2	2	2	2	2

Table 3-4 – Petrophysical Parameters Used in KN01 Analysis to Calculate Clay Volume

	Zone 1: Upper	Zone 2: Middle Shale	Zone 3: Lower Shale	Zone 4: B Sand	Zone 5: C Sand	Zone 6: Lower C Sand	Zone 7: CD Shale	Zone 8: D Sand
Top m TVDSS	3500	3831.2	3936.6	4583.7	4693.5	4740.8	4817.8	4835.9
Base mTVDSS	3831.2	3936.6	4583.7	4693.5	4740.8	4817.8	4835.9	4908.3
Rw	0.268	0.268	0.268	0.268	0.268	0.268	0.268	0.268
Rmf Temp	60	60	60	60	60	60	60	60
Rho Dry Clay	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75
Den Hc app								
Porosity Method	Density	Density	Density	Density	Density	Density	Density	Density
Delta Phi max	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Sat Equation	Archie PhT	Archie PhT	Archie PhT	Archie PhT	Archie PhT	Archie PhT	Archie PhT	Archie PhT
n Exponent	2	2	2	2	2	2	2	2
m source	Param	Param	Param	Param	Param	Param	Param	Param
Salt Logic	No	No	No	No	No	No	No	No
Phie Limit	0	0	0	0	0	0	0	0
Swi Limit	0	0	0	0	0	0	0	0
Clay Shale Ratio	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Rmf Salinity Kp	87.8	87.8	87.8	87.8	87.8	87.8	87.8	87.8
Rw Temp	60	60	60	60	60	60	60	60
Rho Sxo zone								
Hc Den	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
GD Source	Param	Param	Param	Param	Param	Param	Param	Param
OBM?	No	No	No	No	No	No	No	No
M vari with Vcl	No	No	No	No	No	No	No	No
a factor	1	1	1	1	1	1	1	1
Invasion factor	2	2	2	2	2	2	2	2
N source	Param	Param	Param	Param	Param	Param	Param	Param
PhiT Clay								
Vcl Limit	1	1	1	1	1	1	1	1
Anhydrite Logic	No	No	No	No	No	No	No	No
Force 100% Wet	No	No	No	No	No	No	No	No
Rwb Salinity Kp	87.8	87.8	87.8	87.8	87.8	87.8	87.8	87.8
Rmf	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Rh Wet Clay	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Hc Den Min	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Rho GD	2.655	2.655	2.655	2.655	2.655	2.655	2.655	2.655
Phi max	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Vcl cut-off	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
M exponent	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Sxo Method	Inv Fac	Inv Fac	Inv Fac	Inv Fac	Inv Fac	Inv Fac	Inv Fac	Inv Fac
Coal Logic	No	No	No	No	No	No	No	No
Phie Sw Limit	0	0	0	0	0	0	0	0
Kill Logic	No	No	No	No	No	No	No	No
Den Hyd model	Modified	Modified	Modified	Modified	Modified	Modified	Modified	Modified
Rw Salinity Kpp	28	28	28	28	28	28	28	28
Rmfb Salinity K	87.8	87.8	87.8	87.8	87.8	87.8	87.8	87.8

Table 3-5 - Petrophysical Parameters Used in KN01 Analysis to Calculate Porosity/Water Saturation

3.6 Karish North 01 ST01: Petrophysical Analysis Results

The parameters used in the KN01 ST01 petrophysical analysis are the same as those used in KN01 and presented in **Table 3-4** and **Table 3-5**

3.6.1 A Sands

In summary, over the A sand section in this well, the section is similar to the original KN01 borehole, no net sand was calculated over this interval as the section was predominantly shale prone with minor siltstones.

3.6.2 B Sands

The B Sand interval in KN01 ST01 was predominantly shale prone as was indicated by the KN01 borehole. (**Figure 3-8**) As with the KN01 borehole, three thin sands were present in the same interval of the overall B Sand section. The overall NTG (Reservoir) for the B Sand section was 0.078, whilst the NTG (pay) was much lower 0.048, which again reflects not just the overall shale prone lithology, but also the thinly bedded nature of the sand sections. Log based water saturations are affected by thin bed issues supressing the resistivity and causing too high a water saturation being calculated. In this well the borehole angle slightly minimises this influence when compared to the near vertical KN01 borehole. Over the net interval the average porosity was calculated to be 22.7% (Res) and 26.7% (Pay), again showing a thin bed/bed boundary reduction effect. This effect is minimised due the increased deviation of the wellbore. It is envisaged that over the pay section, saturations should be in the order of between 10-20%, rather than the average of 35% as calculated from the NTG criteria.

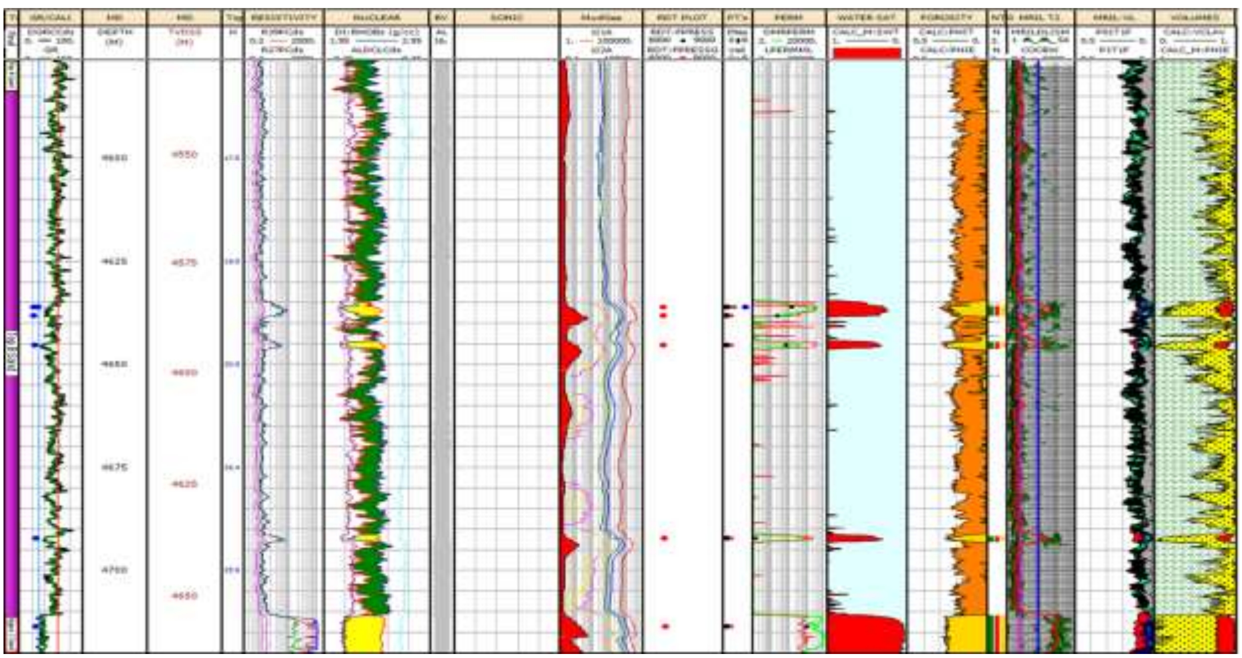


Figure 3-8 – KN01 ST01 B Sand Petrophysical Summary Plot

3.6.3 C Sands

The Upper C Sand reservoir in KN01 ST0 is, again, a high NTG sandstone with excellent reservoir properties, which is consisted across all data sources (**Figure 3-9**). The section is dominated by thick sandstones with thin shale interbeds. The NTG (Reservoir) is calculated to be 0.892, whilst over the NTG (Pay) the value is 0.889. The porosity over the Res and Pay intervals are very similar, around 22.8%, whilst the average Sw over the pay section is calculated to be 17.6%. These values compare favourably with the data calculated from the KN01 borehole. Thin beds are not an issue in the Upper C Sand as shown by the small decrease in NTG between Reservoir and Pay criteria.

The Lower C Sand interval in KN01 ST01 is a highly interbedded shale/silt/sand section (**Figure 3-10**). NTG varies between Reservoir and Pay criteria, as with the KN01 borehole. The deviated borehole, compensates slightly for the thin bed/bed boundary issues, so the reduction from a NTG (Reservoir) to a NTG (Pay) is not as severe, with NTG (Reservoir) calculated to be 0.414 and NTG (Pay) at 0.248.

The average total porosity over the Lower C Sand, is 18.8% over the NTG (Reservoir) and 21.3% over the NTG (pay). As with KN01, this reflects the thin bed/bed boundary affects concerning the water saturation determination and cutoff value used. The average water saturation value calculated over this interval using the NTG (pay) criteria, was calculated to be 45%. This is considered to be too high a value, due resistivity suppression associated with thin beds/bed boundaries, and should be in the range 20-25%.

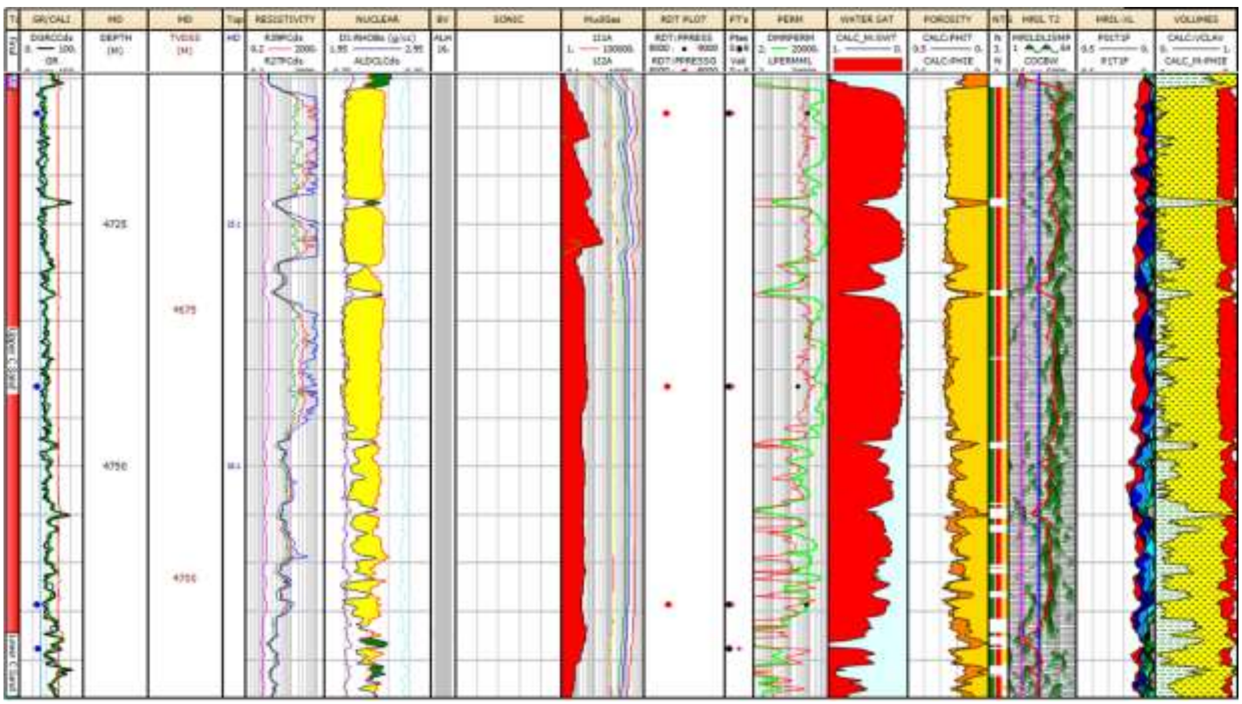


Figure 3-9 – KN01 ST01 UpperC Sand Petrophysical Summary Plot

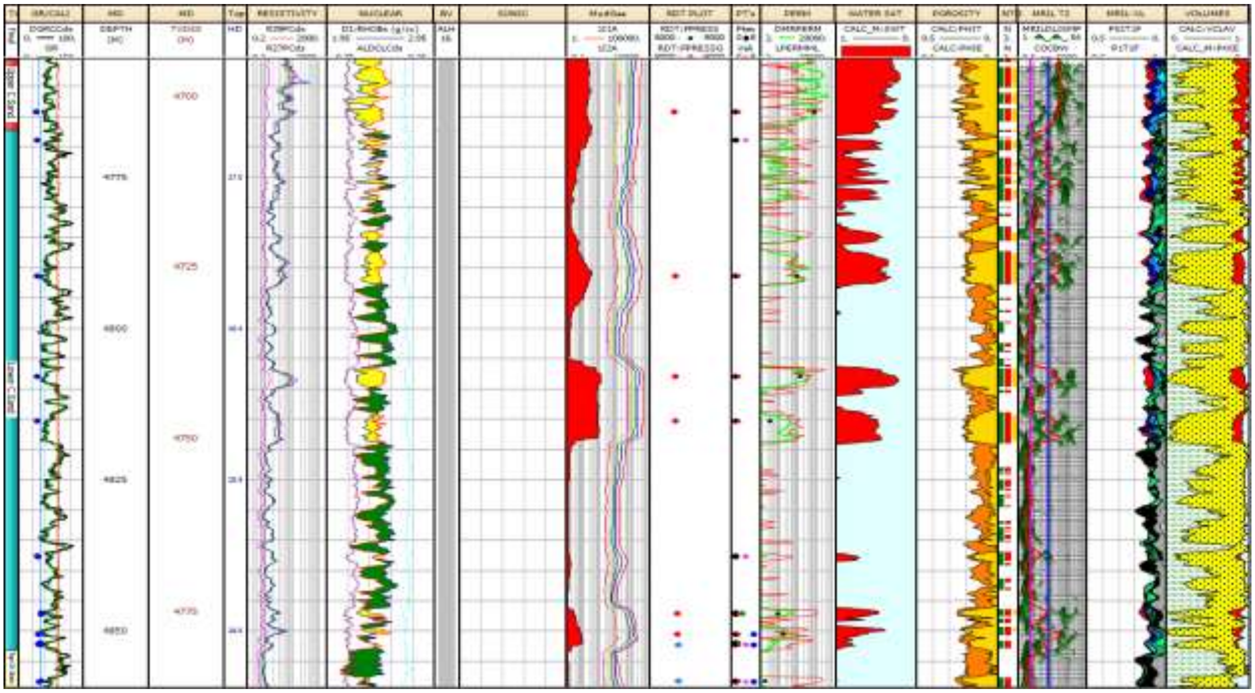


Figure 3-10 – KN01 ST01 Lower C Sand Petrophysical Summary Plot

3.6.4 CD Shale and D Sands

The CD Shale divides the Lower C Sands gas bearing from the water bearing D Sand intervals below (**Figure 3-11**). The CD Shale is predominantly shale. An approximately 3m TVT, water bearing sandstone, is situated towards the top of the CD Shale interval. This sandstone interval, with good net reservoir properties, which was gas bearing in the KN01 motherbore, is water filled. Two RDT water samples were taken in this bed at 4858.23 m MDRKB (4785.1m ss) and 4859.7 m MDRKB (4786.4m ss).

The NTG (Reservoir) for the CD Shale was calculated to be 0.086. The total porosity averaged 23.1% over the NTG (Reservoir) and the section was water wet, with no appreciable hydrocarbons seen in the mud gas data or calculated from the petrophysical analysis.

Below the CD Shale, the D Sand Interval was encountered (**Figure 3-11**). It was found to be a highly interbedded, predominantly shale sequence with thin sands and shales. The section is below the GWC and is considered to be water bearing based on the mudlog shows and the petrophysical interpretation. The NTG (Reservoir) for this interval is 0.326 and the average total porosity is 21.7%.

All deeper reservoir units are not considered to be hydrocarbon bearing in the Karish North field.

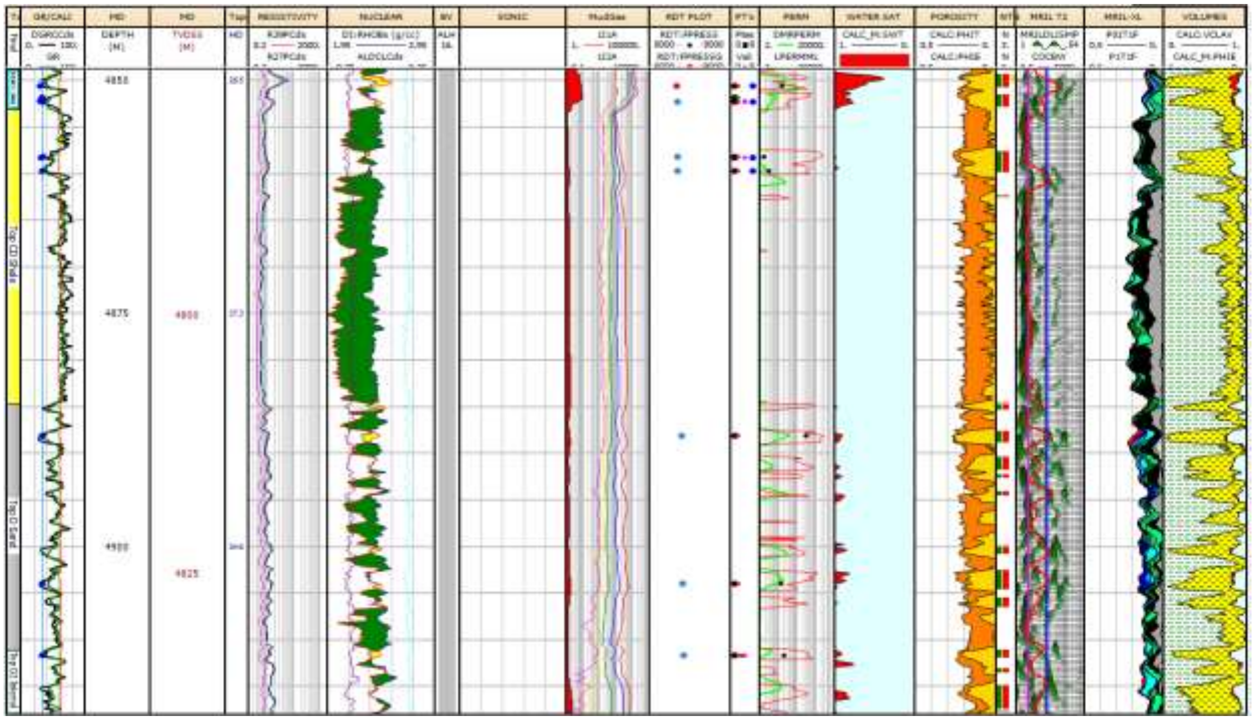


Figure 3-11 – KN01 ST01 CD Shale/D Sand Petrophysical Summary Plot

Reservoir Summary

Zn #	Zone Name	Top m	Bottom m	Gross m	Net m	N/G	Av Phi	Av Sw	Av Vcl Ari	Av PERM(A) Ari	Av PERM(G) Geo	Phi*H	PhiSo*H
1	Top B Sand	4583.48	4711.04	127.56	9.99	0.078	0.227	0.510	0.209	3707.352	69.239	2.26	1.11
2	Upper C Sand	4711.04	4767.20	56.16	50.11	0.892	0.229	0.177	0.113	1048.48	596.06	11.46	9.43
3	Lower C Sand	4767.20	4853.11	85.91	35.60	0.414	0.188	0.573	0.218	337.37	67.96	6.70	2.86
4	Top CD Shale	4853.11	4884.66	31.55	2.71	0.086	0.231	0.990	0.243	1523.33	680.12	0.63	0.01
5	Top D Sand	4884.66	4911.07	26.41	8.61	0.326	0.217	0.953	0.244	893.37	316.75	1.87	0.09
6	Top D2 Interval	4911.07	4944.28	33.21	22.98	0.692	0.217	0.898	0.197	1234.22	322.28	4.99	0.51
7	Top D3 Interval	4944.28	5030.06	85.78	4.20	0.049	0.256	0.915	0.282	4496.68	2591.65	1.08	0.09
8	Top D4 Interval	5030.06	5186.80	156.74	27.95	0.178	0.218	0.904	0.198	1118.97	343.36	6.10	0.59
	All Zones	4583.48	5186.80	603.32	162.35	0.269	0.216	0.585	0.182	1105.75	418.75	35.05	14.54

Pay Summary

Zn #	Zone Name	Top m	Bottom m	Gross m	Net m	N/G	Av Phi	Av Sw	Av Vcl Ari	Av PERM(A Ari	Av PERM(G Geo	Phi*H	PhiSo*H
1	Top B Sand	4583.48	4711.04	127.56	6.09	0.048	0.267	0.350	0.149	5994.992	163.607	1.63	1.06
2	Upper C Sand	4711.04	4767.20	56.16	49.91	0.889	0.229	0.176	0.113	1052.54	604.30	11.43	9.42
3	Lower C Sand	4767.20	4853.11	85.91	21.30	0.248	0.213	0.450	0.163	524.03	256.67	4.54	2.50
4	Top CD Shale	4853.11	4884.66	31.55	0.00	0.000	---	---	---	---	---	---	---
5	Top D Sand	4884.66	4911.07	26.41	0.00	0.000	---	---	---	---	---	---	---
6	Top D2 Interval	4911.07	4944.28	33.21	0.00	0.000	---	---	---	---	---	---	---
7	Top D3 Interval	4944.28	5030.06	85.78	0.00	0.000	---	---	---	---	---	---	---
8	Top D4 Interval	5030.06	5186.80	156.74	0.00	0.000	---	---	---	---	---	---	---
	All Zones	4583.48	5186.80	603.32	77.40	0.128	0.227	0.264	0.130	1172.43	638.74	17.53	12.91

Table 3-6 – Petrophysical Layer Averaged Analysis Results and Summation for KN01 ST01

3.7 Karish North 01 ST02 and Karish North 01 ST03: Petrophysical Analysis Results

Operational issues resulted in the abandoning of the KN01 ST02 well before the well intersected the main reservoir zones. The subsequent well, KN01 ST03, drilled successfully to TD in the D sand, with the specific objective of determining the GWC through the acquisition of formation pressures.

During the drilling of the 12.1/4” section, only a LWD dual gamma ray (DGR) and an Electromagnetic Wave Resistivity Tool (EWR-P4) was acquired (see **Figure 3-12**). The limitations of this LWD dataset did not allow for a full petrophysical interpretation of the KN01 ST03 reservoir section, but this data was used to select sites for formation pressures to be acquired using Halliburton’s LWD GeoTap formation pressure tool. Depth control and locating the GeoTap probe over good quality sands proved a little difficult, 15 of the 27 pressure build-ups recording good stabilisation, while 12 were considered low permeability and the build-ups not stabilised.

Prior to comparing the KN01 ST03 GeoTap pressures against the existing datasets for KN01 and KN01 ST01, the KN01 ST03 LWD data had to be shifted to depth match the wireline data (Section 5.2.2.2.2) as no wireline run was attempted.

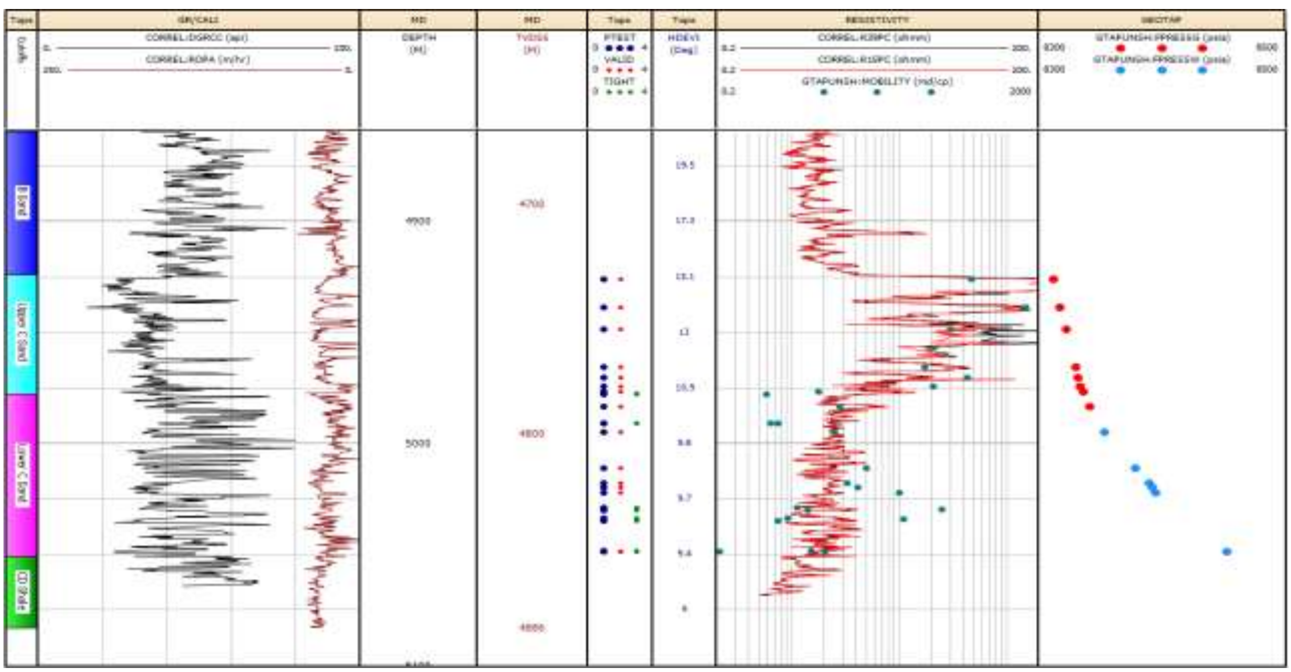


Figure 3-12 – KN01 ST03 Summary Log Including GeoTap Pressure Data

3.8 Formation Pressure Interpretation (Free Water Level)

The RDT data is shown in **Figure 3-13**, which plots the RDT pre-tests pressures for KN01 and KN01 ST01 against TVDSS depth. The plot also presents the gamma ray log as well as the neutron density in TVDSS depth space alongside the pressure data. In addition, the plot also illustrates where samples were taken, and what fluid was collected.

The plot shows that the B Sand pressure is slightly higher than the C Sand Interval below by approximately 10psi, and has a different gradient 0.12 which suggests a lighter gas composition than the C Sands below. The C Sands, both Upper and Lower clearly show a gas gradient of 0.146psi/ft (0.479 psi/m), being richer than the gas in the equivalent stratigraphic unit of Karish Main.

In KN01 a gas sample was taken in the sandstone towards the top of the CD Shale at a depth of 4772 mTVDss, which on analysis had a high, single flash condensate to gas ratio (CGR) of 72 bbl./stb – much higher than the samples taken above this interval.

Samples were also taken in KN01 ST01 and again demonstrated a compositional gradient, one which sees the gas become significantly wetter with depth. The deepest gas sample taken in the Lower C Sands in KN01 ST01 well was at 4778.2 m TVDSS. A gas and water sample was recovered from 4779.7 mTVDSS Furthermore, from the KN01 ST01 borehole, water samples were recovered from the sand in the CD Shale from depths 4785 mTVDSS and 4786.4 mTVDSS, this sand was gas bearing in the KN01 well.

For well KN01 ST01 the additional data helps to define a FWL using the water gradient analysis from the D Sands in KN-01 ST01 and the gas gradient as shown by the pre test data in both KN-01 and KN-01 ST01 in the C Sands, giving a free water level (FWL) of 4767 m ss, which is shallow than the deepest gas sample.

The KN-01 ST03 well targeted the same sequence as seen in KN01 and KN01 ST01, but was planned to intersect the FWL/GWC shallower in the section, within the C Sands to better define the contact. The geological (areal) target was the DHI proven to be the GWC.

Due to wellbore geometey, no wireline data acquisition was attempted in the well. Pressure data was acquired using Halliburton/Sperry LWD GeoTap formation pressure tool, with the data to be acquired as soon after reaching TD as possible. The available real time LWD gamma ray and resistivity was used to select a pretest program.

The main issue with using LWD data was the difference in depth which occurs between wireline and LWD. It was found that a +3.48 shift to the LWD data under tension mode would approximate a potential wireline depth in this well. In addition a -4psi was placed on the GeoTap pressure data to account for elevated ECDs in a dynamic borehole with pumps on. This overlays the GeoTap pre test pressures in the main C Sand section, with those acquired on RDT in KN01 and KN01 ST01. The data is presented in **Figure 3-14** and clearly defines a FWL/GWC in the Lower C Sand at a depth of 4791 m ss. The plot also illustrates the pressure off set of the D Sands which should not be used to define the main GWC in the Karish North Field. The pressure offset between the D Sands to the C Sands is approximately -20 psi. The plot also highlights the pressure issues seen on the RDT data in the lowest section of the Lower C Sands and the thin sandstone within the CD Shale, which appear to be in a separate pressure cell which is isolated to the main C Sand pressure system.

It is very likely that Karish North East Crest and East Slope have a deeper GWC than the other Karish North substructures. The fault that separates Karish North East Crest from Karish Main tips-out to zero offset at approximately 4820m TVDSS. It is therefore extremely likely that Karish North East Crest, East Slope and the Karish Main field share a common aquifer. The most likely GWC is therefore the intersection of the KN01 gas line with the Karish Main aquifer line, giving a FWL of 4823m TVDSS (**Figure 3-15**). This interpretation is also consistent with the deeper amplitude anomaly mapped (by D&M) across the Karish North eastern crest and east slope.

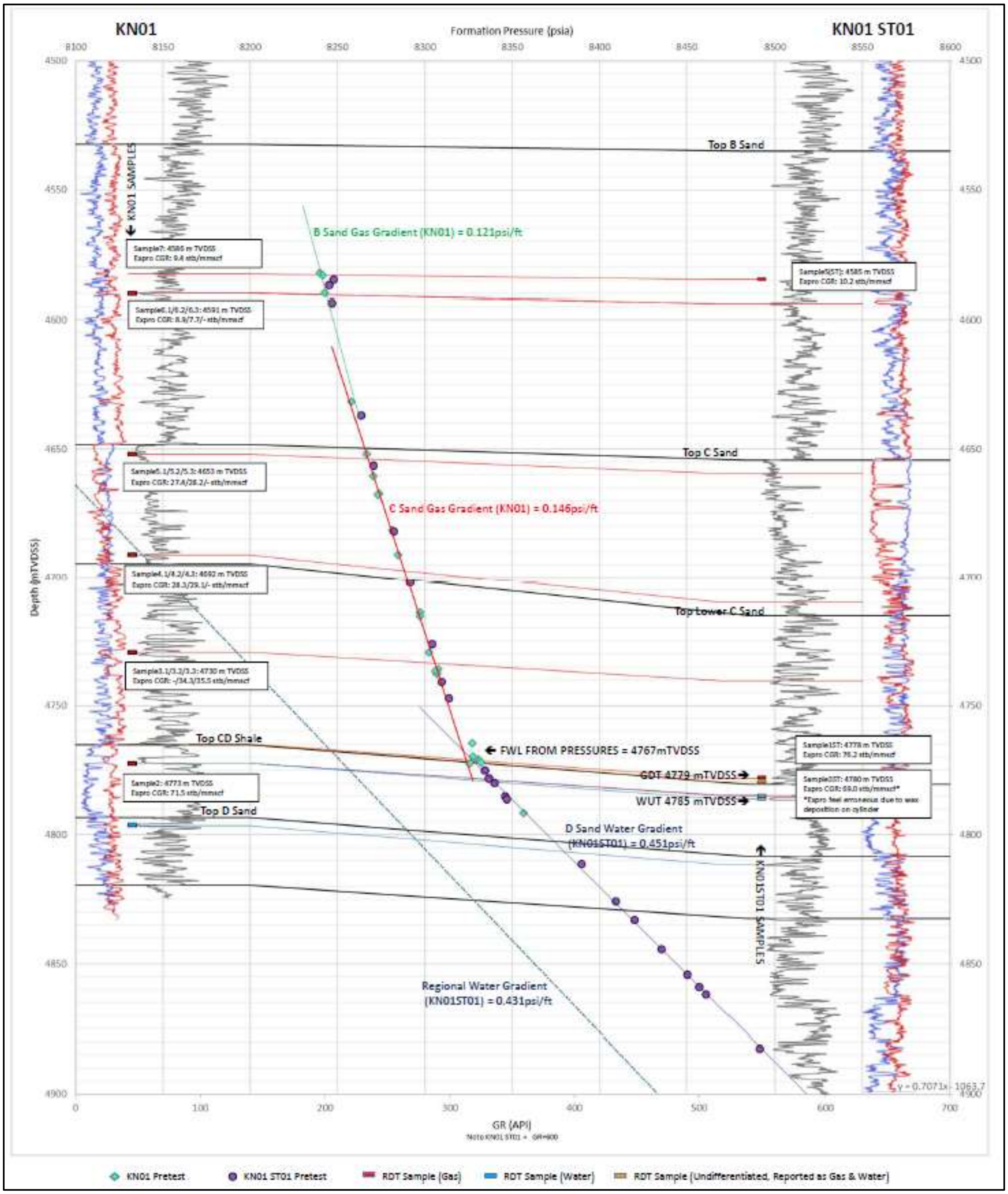


Figure 3-13 – KN01/KN01 ST01 RDT Formation Pressure Interpretation

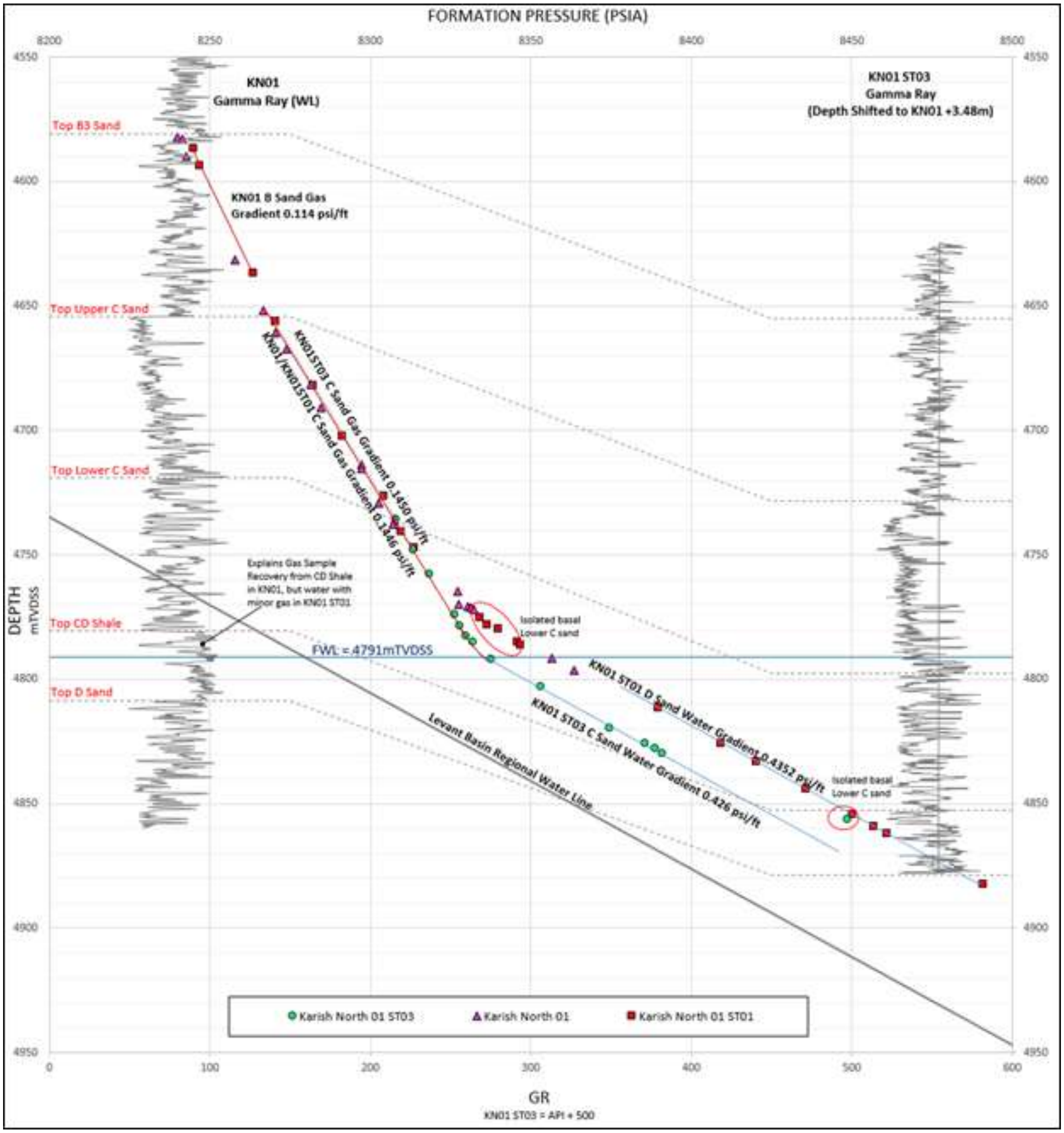


Figure 3-14 – Interpretation of KN01/KN01 ST01 RDT Formation Pressures and KN01 ST03 GeoTap Formation Pressure (depth and pressure corrected)

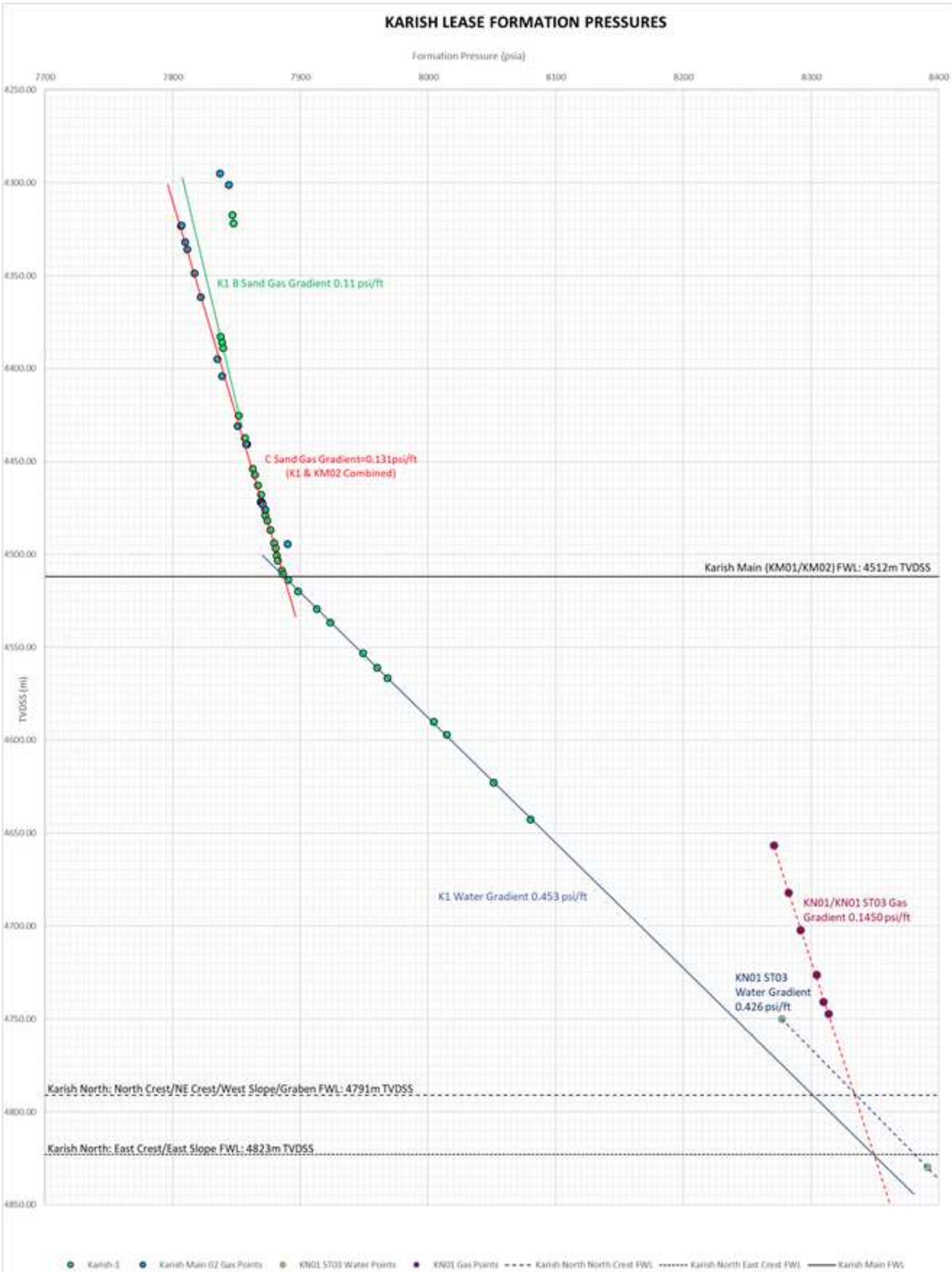


Figure 3-15 – Interpretation of FWL in Karish North East Crest and Karish North East Slope at 4823m TVDSS

3.9 Petrophysical Conclusions

The original almost vertical borehole KN-01 was drilled as successfully as planned, with the vast majority of the formation evaluation data planned being acquired. There were some issues with the NMR MRIL-XL, resulted in only partial coverage of this tool. Subsequently, sidetrack wells from this original borehole were drilled and further formation evaluation data was collected to supplement the data acquired in the original KN-01 borehole. However, drilling issues and related borehole conditions, dictated and controlled the eventual wireline and LWD operations, limiting the data acquisition in these subsequent sidetracks.1

A single 27 m conventional core was taken in the KN-01 borehole over the Upper C Sand interval and full conventional core analysis and special core analysis programs are currently being undertaken on the core material recovered from the well, along with detailed sedimentology and petrography study.

All the wells drilled on the Karish North structure encountered a similar stratigraphical column, with thin gas bearing sands being intersected at the B Sand level, underlain by a high NTG gas bearing Upper C Sand interval, below which a gas bearing highly interbedded Lower C Sand occurred. The KN-01 borehole reached total depth (TD) in water bearing D2 Sands below the CD Shale, whilst the KN-01 ST01 well TD'd in lower, water bearing D4 Interval sands, after encountering water bearing D Sand, D2 and D3 sands. The KN-01 ST03, TD'd in the CD Shale after encountering the gas-water contact (GWC) in the upper section of the Lower C Sands.

A GWC was noted in the lowest most Lower C Sand in the KN01 ST01 well and in the thin sand in the CD Shale, between the Lower C Sands and the D Sand Interval in KN-01 borehole. The GeoTap LWD pressure data defines a GWC in the upper section of the Lower C Sand in well KN-01 ST03. Precise fluid contact definition from gradient analysis prior to drilling KN-01 ST03 is difficult due to the change in fluid composition close to the GWC and that the contact is generally in the interbedded sand and shale sections in each of the wells.

Thin bed/bed boundary issues are prevalent in the section, especially over the B Sand and Lower C Sand intervals. Log based water saturation calculations and to a much lesser extent log based porosity values are affected by the poor log responses in thin beds, which do not accurately measure the true bed response for the various wireline and LWD deployed.

Further detailed analysis is proposed, which will use the core petrophysical data, along with the high resolution resistivity images, coupled with the core sedimentological data to better define the overall volumetric contribution to all sections within the Karish North reservoirs.

Due to hole conditions the main LWD porosity tools in the KN-01 ST01 hole are of poor quality and should not be used in the volumetric analysis of the Karish North structure. As the original KN-01 well trajectory is extremely close to the KN-01 ST01 well, it is considered that the impact of this data issue is low.

Wireline and LWD operations were compromised by poor hole conditions, resulting is less than planned data acquisition programs. In addition, coring as well also proved to be difficult, resulting in less core being recovered, especially over the B Sands interval than what was planned and required.

Action plans have been put in place for future wells to be drilled near to Karish Main and Karish North Fields, including adjacent licence Blocks. The main mitigating plan is to add an additional casing string just above the main Karish reservoirs, therefore putting the difficult section behind casing prior to drilling out the reservoir sections. It is this interval that has caused a number of hole quality issues, resulting in multiple drilling and wireline operation problems in the wells drilled to date. This will result in drilling the reservoir section in a smaller hole size, with the intent to maximising hole quality, and hence data acquisition, including LWD, wireline and coring, where it is considered that coring operations in an 8 ½" hole will proved to be simpler.

4 Geological Model

4.1 Approach and key uncertainties

A deterministic workflow has been generated in Petrel 2016.2 from which a suite of geological models has been generated for Karish North. Reference case variables have subsequently been used in the workflow to generate a 'Reference Case' deterministic geological model, which should be considered a best technical case for Karish North.

The objective of the deterministic geological modelling study was to generate static models that 1) describe the geology of the Karish North discovery, 2) capture the best technical assessment of the Gas Initially in Place (GIIP) and 3) result in an orthogonal grid capable of being simulated for the purpose of well optimisation, forecasting and profile generation.

The range of uncertainty in the static geological parameters has been captured in a probabilistic workflow, with a range of GIIP values output (Section xx) to address the geological uncertainty.

4.2 Input Data

4.2.1 Well Data

Wells available in Karish Lease as inputs to Karish North are:

Well	Description	Year	Operator
Karish North 01	Pilot Hole	2019	Energean Israel
Karish North 01 ST01	Pilot Hole	2019	Energean Israel
Karish North 01 ST02	Pilot Hole - Failed to reach Tamar Sandstone Fm	2019	Energean Israel
Karish North 01 ST03	Pilot Hole	2019	Energean Israel
Karish-1	Karish Discovery Well	2013	Noble Energy
Karish Main 01	Pilot Hole	2019	Energean Israel
Karish Main ST01 01	Production Well	2019	Energean Israel
Karish Main 02	Pilot Hole	2019	Energean Israel
Karish Main ST02 01	Production Well	2019	Energean Israel
Karish Main 03	Pilot Hole - Failed to reach Tamar Sandstone Fm	2019	Energean Israel
Karish Main ST03 01	Production Well	2019	Energean Israel

The Tanin-1 well has not been used as an input to the geological model due to the 45km lateral offset from the Karish North field. Further, regional well data, namely Myra-1 and Aphrodite-2, which were purchased as part of the 1st Israel Offshore Round data package from the Ministry of National Infrastructures, Energy and Water Resources, have not been explicitly used in the Karish North geological model owing to the large lateral offset distances making any resulting geological grid unmanageable. Observations and interpretations from these wells have however, been included in the conceptual model and most significantly in the Operator's assumptions for the aquifer strength (Section 6.4).

4.2.2 Formation Tops

For the purpose of constructing a geological model for Karish North, a comprehensive set of formation tops has been interpreted for all wells in the Karish Lease. Conventional correlation based on the available well logs suites has been carried out. In addition, the interpreted formation tops have been constrained by the wealth of biostratigraphic data from Petrostrat (2018-2019).

The resulting correlation of the major stratigraphic units of the Early Miocene is shown in **Figure 4-1**, **Table 4-1** and **Table 4-1**.

In addition to the regional major stratigraphic units, and in the interests of capturing the likely flow units in the reservoir model, a series of Karish Lease specific well tops were also used to constrain the geological model. The tops are shown in **Table 4-2** and further subdivide the B and C sands (Members) into more detailed stratigraphic units

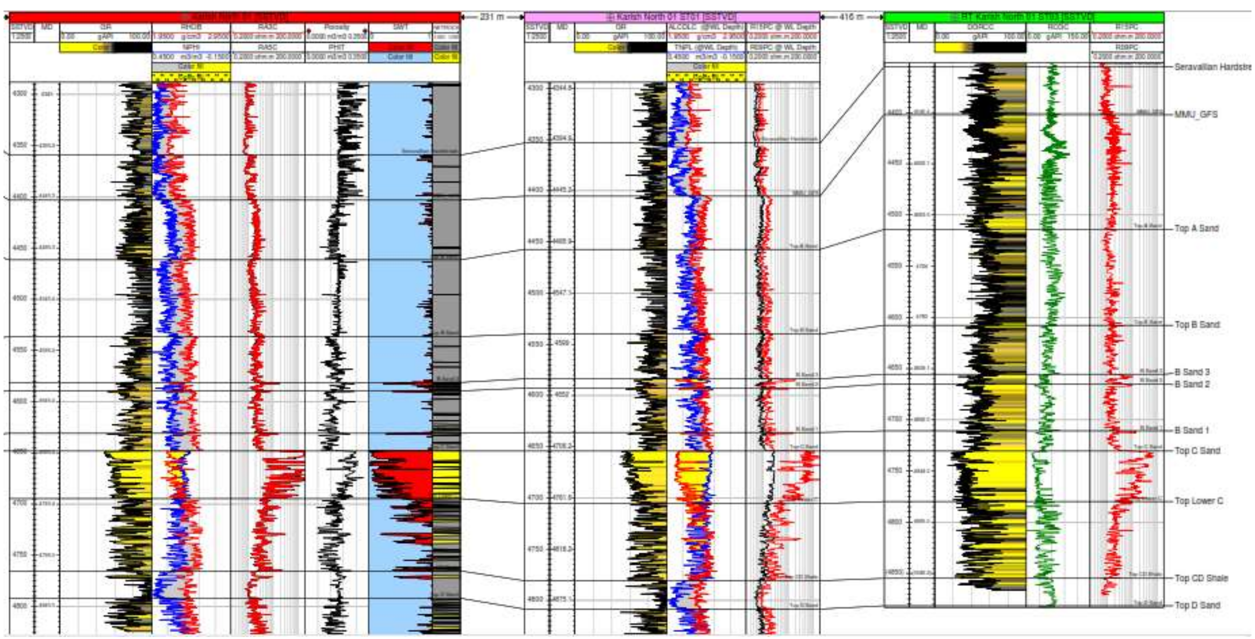


Figure 4-1 – Correlation Panel (High Resolution Version provided in Appendix 1)

Well	Stratigraphic Unit	mMDBRT	mTVDSS	Pick
Karish North 01	Seabed	1764.00	1732.00	LWD
Karish North 01	Top Evaporite	2162.00	2130.00	LWD
Karish North 01	Top Massive Salt	2224.00	2192.00	LWD
Karish North 01	Base Massive Salt	3770.68	3730.75	LWD
Karish North 01	Top Tortonian Sst	4106.1	4063.68	WL
Karish North 01	Base Tortonian Sst	4166.48	4123.24	WL
Karish North 01	Serravalian Hardstreak	4404.44	4359.22	WL
Karish North 01	MMU	4448.46	4403.15	WL
Karish North 01	Top A Sand	4506.84	4461.5	WL
Karish North 01	Top B Sand	4581.81	4536.44	WL
Karish North 01	Top C Sand	4693.58	4648.18	WL
Karish North 01	C Lower	4740.03	4694.6	WL
Karish North 01	Top CD Shale	4810.7	4765.23	WL
Karish North 01	Top D Sand	4837.37	4791.88	WL
Karish North 01 ST01	Seabed	1764.00	1732.00	-
Karish North 01 ST01	Top Evaporite	2162.00	2130.00	Motherbore LWD/ROP
Karish North 01 ST01	Top Massive Salt	2224.00	2192.00	Motherbore LWD/ROP
Karish North 01 ST01	Base Massive Salt	3770.68	3723.22	Motherbore LWD/ROP
Karish North 01 ST01	Top Tortonian Sst	4106.1	4063.68	WL/WL corrected LWD
Karish North 01 ST01	Base Tortonian Sst	4166.48	4123.24	WL/WL corrected LWD
Karish North 01 ST01	Serravalian Hardstreak	4398.36	4353.45	WL/WL corrected LWD
Karish North 01 ST01	MMU	4450.48	4405.25	WL/WL corrected LWD
Karish North 01 ST01	Top A Sand	4503.34722	4457.32	WL/WL corrected LWD
Karish North 01 ST01	Top B Sand	4588.640907	4540.08	WL/WL corrected LWD
Karish North 01 ST01	Top C Sand	4711.04	4654.39	WL/WL corrected LWD
Karish North 01 ST01	C Lower	4767.84	4705.56	WL/WL corrected LWD
Karish North 01 ST01	Top CD Shale	4853.477289	4780.91	WL/WL corrected LWD

Well	Stratigraphic Unit	mMDBRT	mTVDSS	Pick
Karish North 01 ST01	Top D Sand	4884.66	4808.53	WL/WL corrected LWD
Karish North 01 ST02	Seabed	1764.00	1737.68	-
Karish North 01 ST02	Top Evaporite	2162.00	2135.68	LWD/ROP
Karish North 01 ST02	Top Massive Salt	2224.00	2197.68	LWD/ROP
Karish North 01 ST02	Base Massive Salt	3758.33	3724.09	LWD/ROP
Karish North 01 ST02	Top Tortonian Sst	4091.39	4036.00	LWD
Karish North 01 ST02	Base Tortonian Sst	4201.91	4127.42	LWD
Karish North 01 ST02	Serravalian Hardstreak	4485	4355.79	LWD
Karish North 01 ST02	MMU	4543.1	4402.30	LWD
Karish North 01 ST02	Top A Sand	4685.32	4517.68	LWD
Karish North 01 ST02	Top B Sand	4793.27	4608.21	LWD
Karish North 01 ST03	Seabed	1764.00	1737.68	-
Karish North 01 ST03	Top Evaporite	2162.00	2135.68	LWD/ROP
Karish North 01 ST03	Top Massive Salt	2224.00	2197.68	LWD/ROP
Karish North 01 ST03	Base Massive Salt	3758.33	3724.09	LWD/ROP
Karish North 01 ST03	Top Tortonian Sst	4082.5	4035.68	LWD
Karish North 01 ST03	Base Tortonian Sst	4200.5	4134.58	LWD
Karish North 01 ST02	Serravalian Hardstreak	4485	4361.28	LWD
Karish North 01 ST03	MMU	4543.1	4407.88	LWD
Karish North 01 ST03	Top A Sand	4685	4523.38	LWD
Karish North 01 ST03	Top B Sand	4787	4609.18	LWD
Karish North 01 ST03	Top C Sand	4924.34	4736.18	LWD
Karish North 01 ST03	C Lower	4974.5	4785.08	LWD
Karish North 01 ST03	Top CD Shale	5051	4860.68	LWD
Karish North 01 ST03	Top D Sand	5079	4892.68	LWD
Karish-1	Top Massive Salt			
Karish-1	Base Massive Salt	3556.79	3532.79	LWD
Karish-1	Top Tortonian Sst	3824.02	3800.02	LWD
Karish-1	Base Tortonian Sst	3884.87	3860.87	LWD
Karish-1	Seravallian Hardstreak	4131.47	4107.47	LWD
Karish-1	MMU_GFS	4201.64	4177.64	LWD
Karish-1	Top A Sands	4302.93	4278.93	WL
Karish-1	Top B Sand	4366.32	4342.32	WL
Karish-1	B Sand 3	4405.49	4381.49	WL
Karish-1	B Sand 2	4412.2	4388.2	WL
Karish-1	B Sand 1	4448.8	4424.8	WL

Well	Stratigraphic Unit	mMDBRT	mTVDSS	Pick
Karish-1	Top C Sand	4460.55	4436.55	WL
Karish-1	C Lower	4511.72	4487.72	WL
Karish-1	Top CD Shale	4585.49	4561.49	WL
Karish-1	Top D Sand	4613.27	4589.27	WL
KarishMain 01	Seabed	1791.4	1759.8	LWD
KarishMain 01	Top Evaporite	2101	2069	LWD
KarishMain 01	Top Massive Salt	2133	2101	LWD
KarishMain 01	Base Massive Salt	4020	3680	LWD
KarishMain 01	Top Tortonian Sst	4261	3836	LWD
KarishMain 01	Base Tortonian Sst	4343	3890	LWD
KarishMain 01	Serravalian Hardstreak	4650.95	4091.19	WL
KarishMain 01	MMU	4718.75	4135.55	WL
KarishMain 01	Top A Sand (Unc)	4860.19	4236.08	WL
KarishMain 01	Top B Sand (Unc)	4886.26	4256.54	WL
KarishMain 01	Top C Sand	5007	4358.22	WL
KarishMain 01	C Lower	5069	4411.97	WL
KarishMain 01	Top CD Shale	5169.81	4499.06	WL
KarishMain 01	Top D Sand	5199.9	4524.97	WL
Karish Main 01 ST01	Serravalian Hardstreak	4627.6	4089.6	WL
Karish Main 01 ST01	MMU	4697.62	4136.29	WL
Karish Main 01 ST01	Top A Sand (Unc)	4832.31	4232.67	WL
Karish Main 01 ST01	Top B Sand (Unc)	4857.76	4252.53	WL
Karish Main 01 ST01	Top C Sand	4980.61	4354.27	WL
KarishMain 02	Seabed	1789.3	1757.7	LWD
KarishMain 02	Top Evaporite	2083	2051.4	LWD
KarishMain 02	Top Massive Salt	2097	2065.4	LWD
KarishMain 02	Base Massive Salt	3642.42	3567.01	LWD
KarishMain 02	Serravalian Hardstreak	4201.99	4084.7	WL
KarishMain 02	MMU	4250.75	4133.11	WL
KarishMain 02	Top A Sand Equivalent	4303.48	4185.72	WL
KarishMain 02	Top B Sand	4374.13	4256.37	WL
KarishMain 02	Top C Sand (FAULTED)	4439.16	4321.4	WL
KarishMain 02	C Lower	4497.67	4379.91	WL
KarishMain 02	Top CD Shale	4561.86	4444.1	WL
KarishMain 02	Top D Sand	4585.51	4467.75	WL
KarishMain 02 ST01	Serravalian Hardstreak	4196.72	4078.86	LWD
KarishMain 02 ST01	MMU	4243.35	4124.72	LWD

Well	Stratigraphic Unit	mMDBRT	mTVDSS	Pick
KarishMain 02 ST01	Top A Sand Equivalent	4296.58	4177.68	LWD
KarishMain 02 ST01	Top B Sand	4368.31	4249.31	LWD
KarishMain 02 ST01	Top C Sand	4424.2	4305.2	LWD
vvvvvvv	Seabed	1792	1760.4	LWD
KarishMain 03	Top Evaporite	2100	2068.4	LWD
KarishMain 03	Top Massive Salt	2147	2115.4	LWD
KarishMain 03	Base Massive Salt	3935	3567	LWD
KarishMain 03	Top Tortonian Sst	4478	3845	LWD
KarishMain 03	Base Tortonian Sst	4584	3912	LWD
KarishMain 03	MMU	4849	4118	LWD
KarishMain 03	Top A Sand	4989	4254	LWD
KarishMain 03	Top B Sand	5037	4300	LWD
KarishMain 03 ST01	0	4784.16	4061.72	LWD
KarishMain 03 ST01	MMU	4846.09	4115.06	LWD
KarishMain 03 ST01	Top A Sand	4926.88	4189.03	LWD
KarishMain 03 ST01	Top B Sand	5033.23	4292.32	LWD
KarishMain 03 ST01	Top C Sand (FAULTED)	5137.41	4395.48	LWD

Table 4-1 – Major Stratigraphic Formation Tops

Well	Stratigraphic Unit	mMDBRT	mTVDSS
Karish North 01	B Sand 3	4580.94	4626.32
Karish North 01	B Sand 3 Base	4583.79	4629.17
Karish North 01	B Sand 2	4589.45	4634.82
Karish North 01	B Sand 2 Base	4590.6	4635.98
Karish North 01	B Sand 1	4630.8	4676.19
Karish North 01	B Sand 1 Base	4632.37	4677.77
Karish North 01	Top Upper C5	4650.98	4696.38
Karish North 01	Top Upper C4	4666.42	4711.83
Karish North 01	Top Upper C3	4674.18	4719.6
Karish North 01	Top Upper C2	4684.75	4730.18
Karish North 01	Top Upper C1	4690.34	4735.77
Karish North 01	Top Lower C9	4702.42	4747.85
Karish North 01	Top Lower C8	4713.11	4758.55
Karish North 01	Top Lower C7	4717.7	4763.14
Karish North 01	Top Lower C6	4722.23	4767.67
Karish North 01	Top Lower C5	4728.83	4774.27
Karish North 01	Top Lower C4	4734.63	4780.08
Karish North 01	Top Lower C3	4741.94	4787.39
Karish North 01	Top Lower C2	4752.86	4798.32
Karish North 01	Top Lower C1	4759.4	4804.87
Karish North 01	Top CD1 Sand	4769.99	4815.47
Karish North 01	Base CD1 Sand	4772.48	4817.96
Karish North 01 ST01	B Sand 3	4583.69	4634.61
Karish North 01 ST01	B Sand 3 Base	4587.24	4638.4
Karish North 01 ST01	B Sand 2	4592.85	4644.38
Karish North 01 ST01	B Sand 2 Base	4594.69	4646.35
Karish North 01 ST01	B Sand 1	4636.04	4690.96
Karish North 01 ST01	B Sand 1 Base	4637.8	4692.89
Karish North 01 ST01	Top Upper C5	4655.43	4712.18
Karish North 01 ST01	Top Upper C4	4673.81	4732.47
Karish North 01 ST01	Top Upper C3	4680.51	4739.89
Karish North 01 ST01	Top Upper C2	4694.06	4754.96
Karish North 01 ST01	Top Upper C1	4699.58	4761.14
Karish North 01 ST01	Top Lower C9	4710.78	4773.71
Karish North 01 ST01	Top Lower C8	4722.78	4787.27
Karish North 01 ST01	Top Lower C6	4732.87	4798.73
Karish North 01 ST01	Top Lower C5	4739.52	4806.29

Well	Stratigraphic Unit	mMDBRT	mTVDSS
Karish North 01 ST01	Top Lower C4	4745.96	4813.63
Karish North 01 ST01	Top Lower C3	4753.37	4822.09
Karish North 01 ST01	Top Lower C2	4765.27	4835.66
Karish North 01 ST01	Top Lower C1	4772.15	4843.5
Karish North 01 ST01	Top CD1 Sand	4784.61	4857.68
Karish North 01 ST01	Base CD1 Sand	4786.94	4860.33
Karish North 01 ST02	B Sand 3	4641.38	4831.05
Karish North 01 ST02	B Sand 3 Base	4644.07	4834.08
Karish North 01 ST02	B Sand 2	4648.11	4838.61
Karish North 01 ST02	B Sand 2 Base	4649.6	4840.27
Karish North 01 ST02	B Sand 1	4680.91	4875.36
Karish North 01 ST02	B Sand 1 Base	4682.54	4877.18
RT Karish North 01 ST03	B Sand 3	4657.14	4846.87
RT Karish North 01 ST03	B Sand 3 Base	4660.29	4850.28
RT Karish North 01 ST03	B Sand 2	4665.06	4855.41
RT Karish North 01 ST03	B Sand 2 Base	4667.73	4858.3
RT Karish North 01 ST03	B Sand 1	4710.79	4903.83
RT Karish North 01 ST03	B Sand 1 Base	4712.66	4905.79
RT Karish North 01 ST03	Top Upper C5	4732.33	4926.24
RT Karish North 01 ST03	Top Upper C4	4750.18	4944.64
RT Karish North 01 ST03	Top Upper C3	4757.13	4951.78
RT Karish North 01 ST03	Top Upper C2	4768.11	4963.02
RT Karish North 01 ST03	Top Upper C1	4773.92	4968.96
RT Karish North 01 ST03	Top Lower C9	4786.32	4981.58
RT Karish North 01 ST03	Top Lower C8	4796.93	4992.36
RT Karish North 01 ST03	Top Lower C6	4806.53	5002.1
RT Karish North 01 ST03	Top Lower C5	4814.03	5009.71
RT Karish North 01 ST03	Top Lower C4	4820.12	5015.89
RT Karish North 01 ST03	Top Lower C3	4827.89	5023.77
RT Karish North 01 ST03	Top Lower C2	4839.94	5036
RT Karish North 01 ST03	Top Lower C1	4847.56	5043.72
RT Karish North 01 ST03	Top CD1 Sand	4858.27	5054.59
RT Karish North 01 ST03	Base CD1 Sand	4861.14	5057.51
Karish 01	B Sand 3 Base	4384.5	4408.5
Karish 01	B Sand 2	4387.73	4411.73
Karish 01	B Sand 2 Base	4389.56	4413.56
Karish 01	B Sand 1	4424.45	4448.45

Well	Stratigraphic Unit	mMDBRT	mTVDSS
Karish 01	B Sand 1 Base	4426.06	4450.06
Karish 01	Top Upper C5	4440.04	4464.04
Karish 01	Top Upper C4	4456.9	4480.9
Karish 01	Top Upper C3	4461.45	4485.45
Karish 01	Top Upper C2	4471.38	4495.38
Karish 01	Top Upper C1	4481.27	4505.27
Karish 01	Top Lower C9	4493.24	4517.24
Karish 01	Top Lower C8	4508.01	4532.01
Karish 01	Top Lower C7	4518.58	4542.58
Karish 01	Top Lower C6	4521.19	4545.19
Karish 01	Top Lower C4	4533.55	4557.55
Karish 01	Top Lower C3	4540.87	4564.87
Karish 01	Top Lower C2	4550.45	4574.45
Karish 01	Top Lower C1	4556.27	4580.27
Karish 01	Top CD1 Sand	4565.69	4589.69
Karish 01	Base CD1 Sand	4568.22	4592.22
Karish Main 01	B Sand 3	4306.3	4946.68
Karish Main 01	B Sand 3 Base	4306.3	4946.68
Karish Main 01	B Sand 2	4306.3	4946.68
Karish Main 01	B Sand 2 Base	4306.3	4946.68
Karish Main 01	B Sand 1	4344.28	4990.9
Karish Main 01	B Sand 1 Base	4347.18	4994.26
Karish Main 01	Top Upper C5	4365.06	5014.89
Karish Main 01	Top Upper C4	4377.77	5029.55
Karish Main 01	Top Upper C3	4383.12	5035.71
Karish Main 01	Top Upper C2	4391.09	5044.9
Karish Main 01	Top Upper C1	4403.56	5059.28
Karish Main 01	Top Lower C9	4418.77	5076.86
Karish Main 01	Top Lower C8	4433.43	5093.79
Karish Main 01	Top Lower C7	4442.76	5104.59
Karish Main 01	Top Lower C6	4448.07	5110.73
Karish Main 01	Top Lower C4	4460.41	5125.01
Karish Main 01	Top Lower C3	4468.66	5134.56
Karish Main 01	Top Lower C2	4478.82	5146.34
Karish Main 01	Top Lower C1	4491.44	5160.98
Karish Main 01	Top CD1 Sand	4500.45	5171.42
Karish Main 01	Base CD1 Sand	4502.96	5174.34

Well	Stratigraphic Unit	mMDBRT	mTVDSS
Karish Main 01 ST01	B Sand 3 Base	4307.23	4925.1
Karish Main 01 ST01	B Sand 2	4307.23	4925.1
Karish Main 01 ST01	B Sand 2	4307.23	4925.1
Karish Main 01 ST01	B Sand 2	4307.23	4925.1
Karish Main 01 ST01	B Sand 1	4345.25	4970.09
Karish Main 01 ST01	B Sand 1	4345.44	4970.3
Karish Main 01 ST01	B Sand 1 Base	4346.84	4971.95
Karish Main 01 ST01	B Sand 1 Base	4346.84	4971.95
Karish Main 02	B Sand 3	4299.05	4416.81
Karish Main 02	B Sand 3 Base	4302.14	4419.89
Karish Main 02	B Sand 2	4306.24	4424
Karish Main 02	B Sand 2 Base	4308.76	4426.52
Karish Main 02	B Sand 1	4321.4	4439.16
Karish Main 02	B Sand 1 Base	4321.4	4439.16
Karish Main 02	Top Upper C5	4324.03	4441.78
Karish Main 02	Top Upper C4	4340.36	4458.12
Karish Main 02	Top Upper C3	4346.94	4464.7
Karish Main 02	Top Upper C2	4357.71	4475.46
Karish Main 02	Top Upper C1	4367.43	4485.19
Karish Main 02	Top Lower C9	4385.71	4503.46
Karish Main 02	Top Lower C8	4391.47	4509.23
Karish Main 02	Top Lower C7	4397.41	4515.17
Karish Main 02	Top Lower C6	4399.81	4517.57
Karish Main 02	Top Lower C4	4407.68	4525.44
Karish Main 02	Top Lower C3	4415.57	4533.32
Karish Main 02	Top Lower C2	4422.63	4540.39
Karish Main 02	Top Lower C1	4435.18	4552.94
Karish Main 02	Top CD1 Sand	4452.73	4570.49
Karish Main 02	Base CD1 Sand	4453.44	4571.19
Karish Main 02 ST01	B Sand 3	4285.44	4404.43
Karish Main 02 ST01	B Sand 3 Base	4287.96	4406.96
Karish Main 02 ST01	B Sand 2	4290.58	4409.58
Karish Main 02 ST01	B Sand 2 Base	4292.36	4411.36
Karish Main 02 ST01	B Sand 1	4305.2	4424.2
Karish Main 02 ST01	B Sand 1 Base	4305.2	4424.2
Karish Main 02 ST01	Top C Sand	4305.2	4424.2
Karish Main 03 ST01	B Sand 3	4336.17	5075.66

Well	Stratigraphic Unit	mMDBRT	mTVDSS
Karish Main 03 ST01	B Sand 3 Base	4339.54	5079.2
Karish Main 03 ST01	B Sand 2	4344.03	5083.91
Karish Main 03 ST01	B Sand 2 Base	4346	5085.97
Karish Main 03 ST01	B Sand 1	4382.29	5123.88
Karish Main 03 ST01	B Sand 1 Base	4384.26	5125.93
Karish Main 03 ST01	Top Upper C5	4396.88	5139.04
Karish Main 03 ST01	Top Upper C4	4414.41	5157.2
Karish Main 03 ST01	Top Upper C3	4421.52	5164.57

Table 4-2 – Karish Lease Specific Minor Stratigraphic Formation Tops (Tamar Sandstone Formation)

4.3 Structural Model

4.3.1 Pillar Gridding

Grid boundaries have been defined to incorporate the discoveries and all prospects/leads at the Miocene level within the Karish Lease. The grid area for the Karish North geological model is some 81.7km^2, with the skeleton grids being designed to sufficiently cater for all possible future activity on the Karish Lease.

The grid has I/J grid dimensions of 100m x 100m, with the grid dimension being dictated by the close convergence of faults, rather than the minimum geological body size. The grid has been rotated anticlockwise by 22.5° to approximate the azimuth of the main Karish bounding fault strike and subsequently create a more orthogonal grid (**Figure 4-2** and **Figure 4-3**).

The grid incorporates 26 faults. In all cases, the grid has been aligned with the faults, with none of the faults being stair-stepped. All faults have been modelled as linear to ensure an orthogonal grid. The Karish structural model consists of six segments **Figure 4-4**). The skeleton grid has been successfully created without any negative cell volumes and has been successfully initialized in the reservoir simulator.

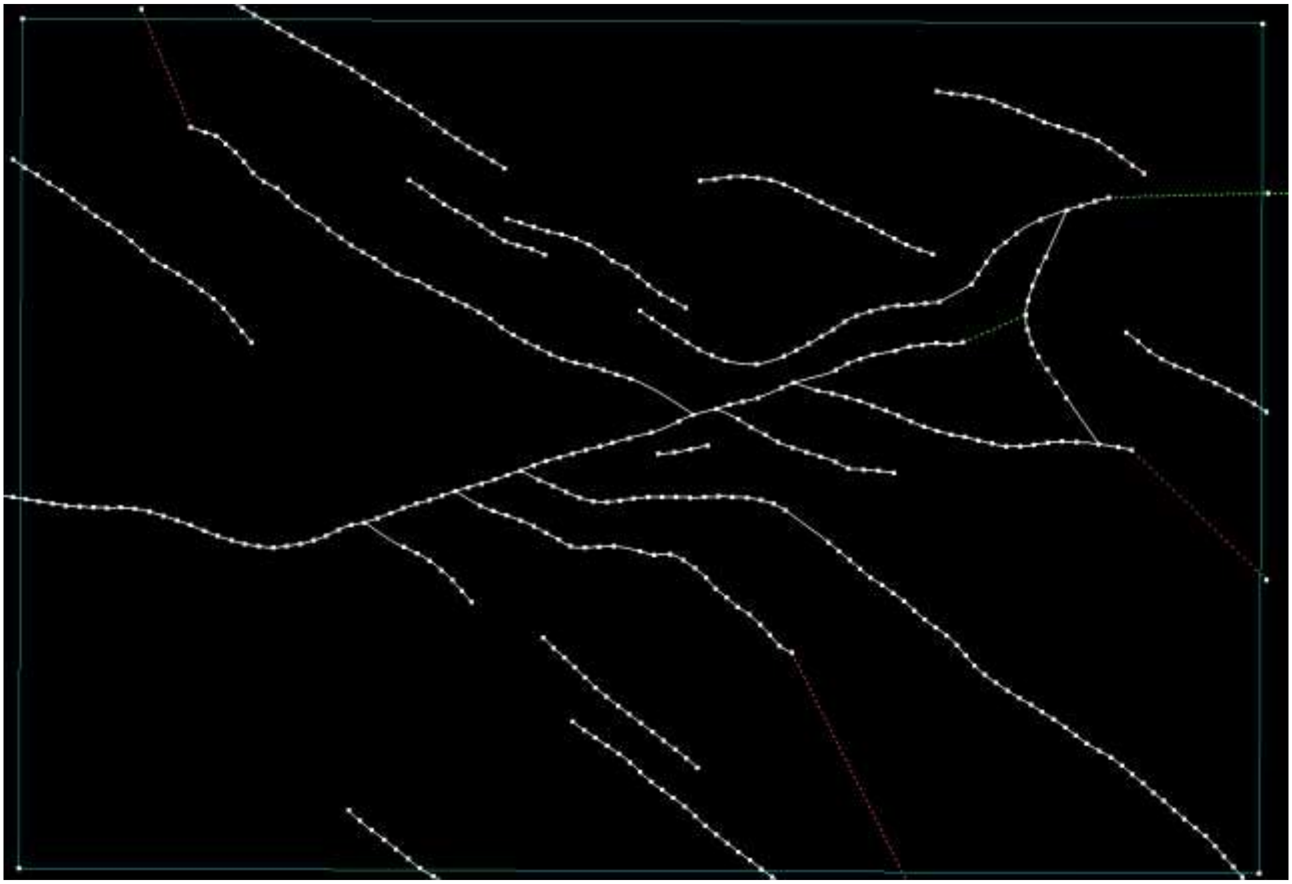


Figure 4-2 – Faults and IJ Trends used in the construction of Reference Case Skeleton Grid

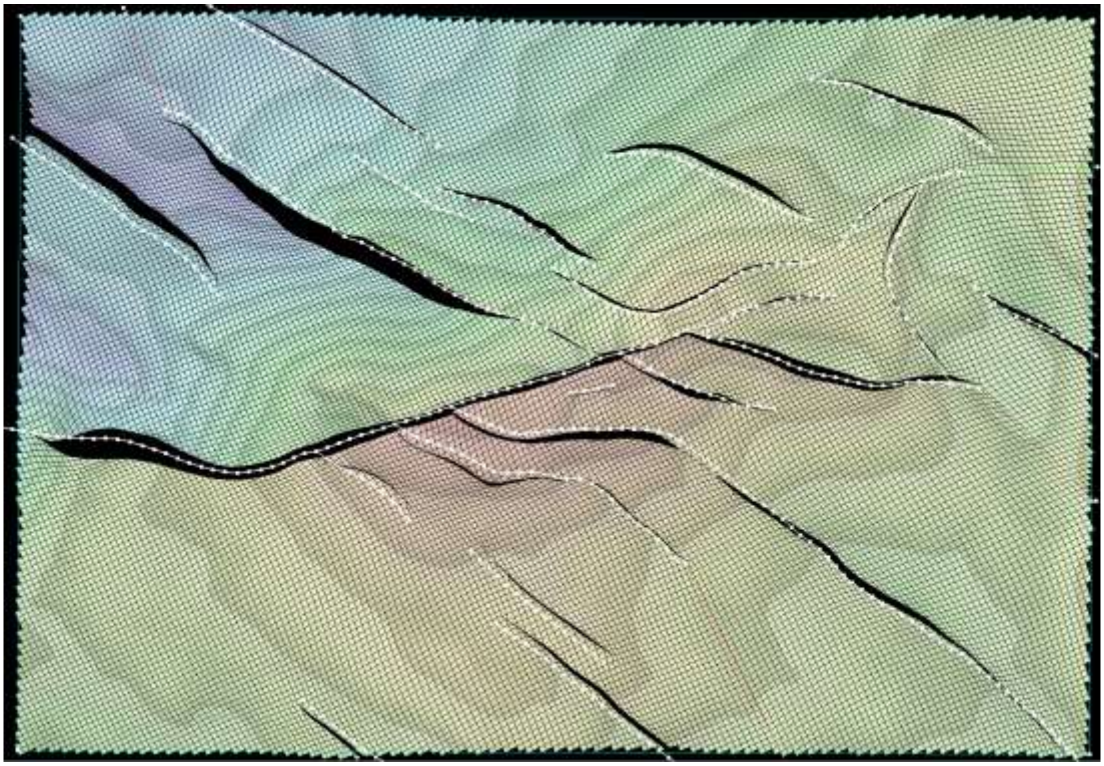


Figure 4-3 – Resulting Reference Case mid Skeleton Grid. Note alignment of grid with main fault azimuth

Figure 4-4 – Geological Model Segments

4.3.2 Horizon Modelling

All seismically interpreted horizons have been used for the geological model, being explicitly modelled as Karish model horizons namely: Near Top A Sand, Top B Sand, Top C Sand, Top D Sand. The near Top A sand horizon is erosive, and as such, occasionally incises into the underlying stratigraphy. This is particularly apparent over the Karish Main structure where seismic scale incision is apparent. Further the correlation of Tanin-1 and Karish-1 also indicates an incision surface within the Karish-1 well (**Figure 4-5**).

Given the complex fault geometries, specifically the close convergence of faults, variable cut-back distances have been used for fault/horizon intersection modelling. In addition, a significant amount of manual editing of the 3D grid was required to generate a grid capable of being simulated.

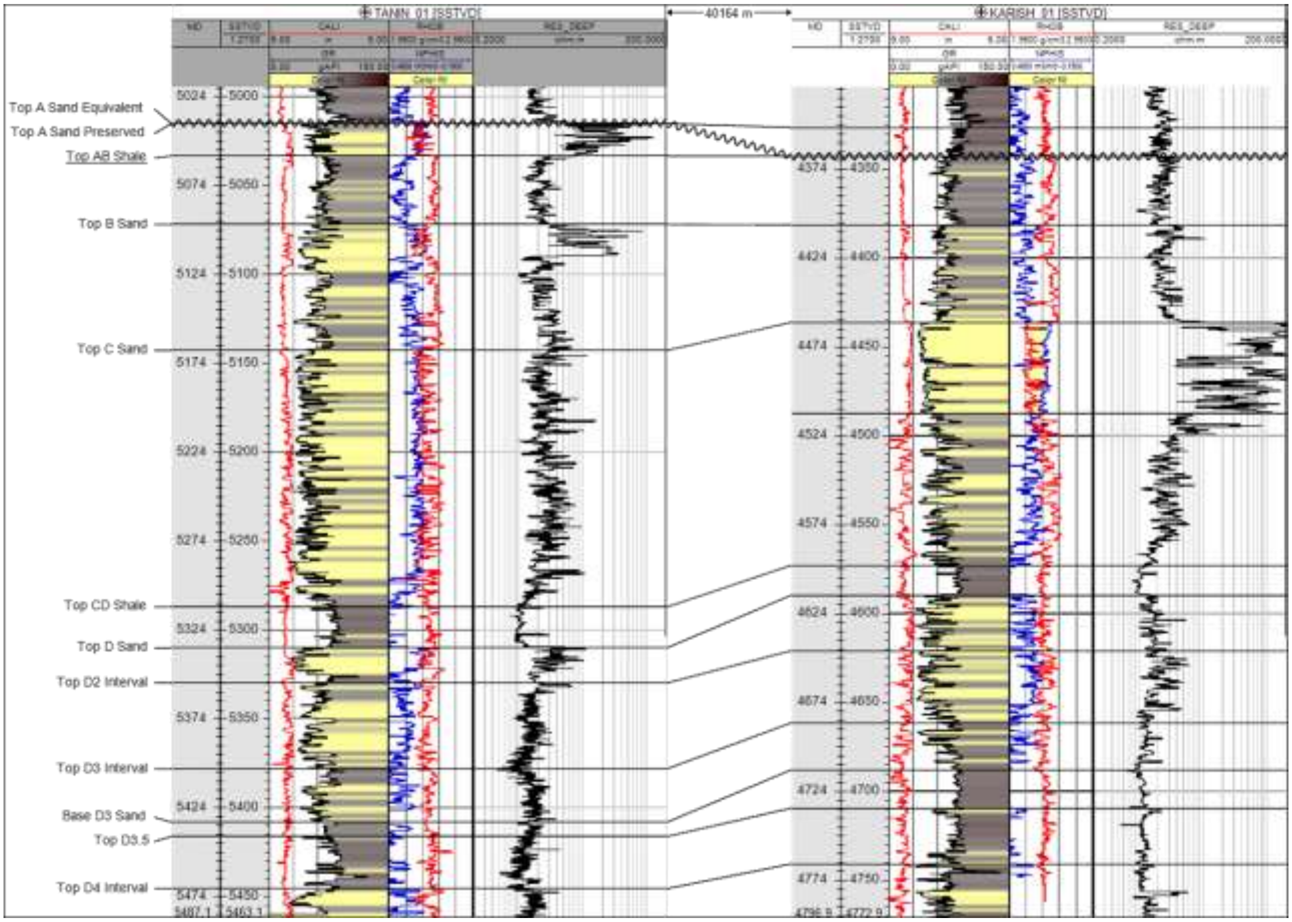


Figure 4-5 – Correlation of the Karish-1 and Tanin-1 wells

4.3.3 Model Zonation

The model zonation has been designed to reflect the high confidence of not only the major stratigraphic units, but the detailed intra-unit correlation, which has been made possible by the comprehensive data acquisition program completed by Energean during the 2019 DrillMAX campaign. The zonation has utilised a correlation which is considered to best reflect the reservoir flow units. All zones are modelled as conformable and have been generated using the minor stratigraphic formation tops shown in **Table 4-2**.A total of 29 zones have been modelled and are shown in **Table 4-3** and **Table 4-3 - Zonation Scheme for the Karish geological model**

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Major Stratigraphic Unit	Zones (Minor Stratigraphic Units)	Description
A Sands	Above A	Non-Net scour infill with donwflank prospectivity
B Sands	B4 Shale	Hertoegeneous net reservoir unit. Conventional and thinly bedded turbidite dominated by mudstones
	B3 Sand	
	B3 Shale	
	B2 Sand	
	B2 Shale	
	B1 Sand	
	B1 Shale	
C Sands	Upper C6 Sand	Massive clean turbidte reservoir sands overlain by more distal/marginal heterogenic sand/shale interbeds
	Upper C5 Sand	
	Upper C4 Sand	
	Upper C3 Sand	
	Upper C2 Sand	
	Upper C1 Sand	
	Lower C10 Sand	
	Lower C9 Sand	
	Lower C8 Sand	
	Lower C7 Sand	
	Lower C6 Sand	
	Lower C5 Sand	
	Lower C4 Sand	
	Lower C3 Sand	
	Lower C2 Sand	
	Lower C1 Sand	
CD Shale	CD Shale Upper	Pelagic shale with minor reservoir sand development
	CD1 Sand	
	CD Shale Lower	
D Sands	D1 Sand	Channelised inner fan deposits of limited lateral extent
	D2 Sand	

Table 4-3 - Zonation Scheme for the Karish geological model

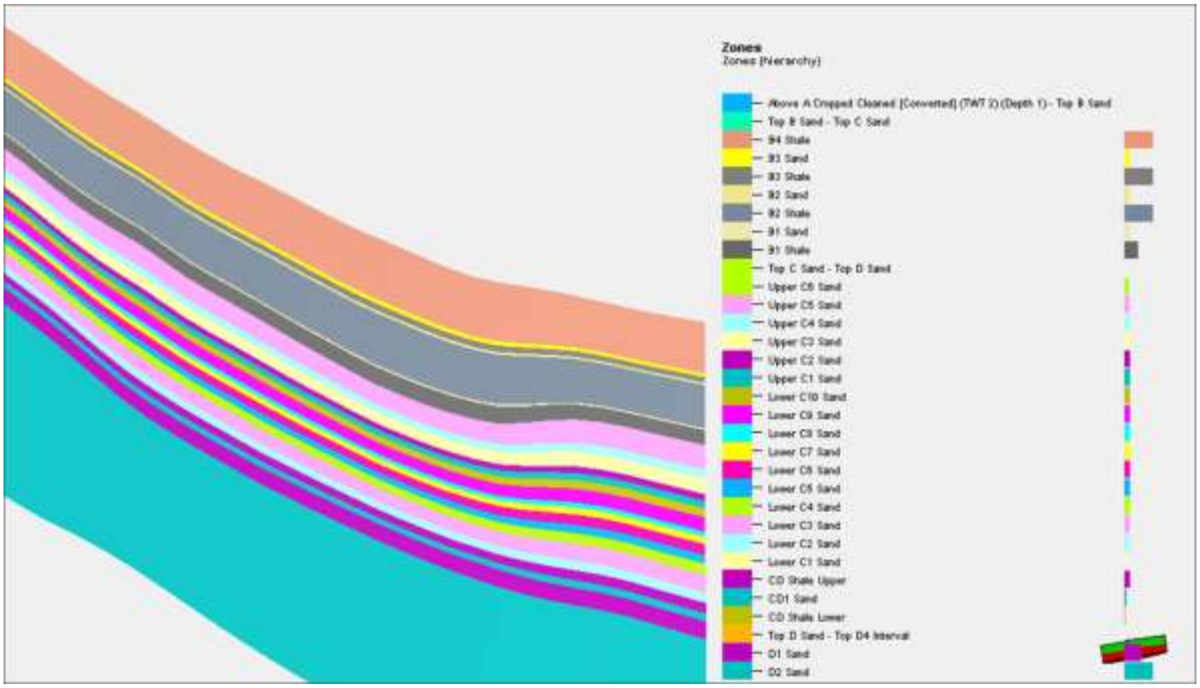


Figure 4-6 – Zonation Scheme for Karish North Geological Model

4.3.4 Model Layering

Using the total porosity log as a QC, different layering numbers were investigated to ensure successful upscaling in terms of preserving the distribution and range of the input data (well log scale), whilst minimising the number of cells for efficient simulation. This was done by visual inspection of the total porosity histogram per zone along with cross-checking the volume weighted statistics per net reservoir unit. Non-net zones were assigned as a single layer to reduce the number of the cells in the geological model as far as practicably possible. The final geological scale static model has 481 layers, and therefore requires upscaling ahead of simulation. All layers are conformable, with the number of layers per zone being shown in **Table 4-4**.

STRATIGRAPHY	METHOD	# LAYERS	CUMULATIVE LAYERS
Above Top B Sand	Proportional	1	1
B4 Shale	Proportional	50	51
B3 Sand	Proportional	10	61
B3 Shale	Proportional	50	111

B2 Sand	Proportional	10	121
B2 Shale	Proportional	50	171
B1 Sand	Proportional	10	181
B1 Shale	Proportional	25	206
Upper C6 Sand	Proportional	10	216
Upper C5 Sand	Proportional	10	226
Upper C4 Sand	Proportional	10	236
Upper C3 Sand	Proportional	10	246
Upper C2 Sand	Proportional	10	256
Upper C1 Sand	Proportional	10	266
Lower C10 Sand	Proportional	10	276
Lower C9 Sand	Proportional	10	286
Lower C8 Sand	Proportional	10	296
Lower C7 Sand	Proportional	10	306
Lower C6 Sand	Proportional	10	316
Lower C5 Sand	Proportional	10	326
Lower C4 Sand	Proportional	10	336
Lower C3 Sand	Proportional	10	346
Lower C2 Sand	Proportional	10	356
Lower C1 Sand	Proportional	10	366
CD Shale Upper	Proportional	10	376
CD1 Sand	Proportional	5	381
CD Shale Lower	Proportional	20	401
D1 Sand	Proportional	30	431

D2 Sand	Proportional	50	481

Table 4-4 – Geological Model Layering & Zonation

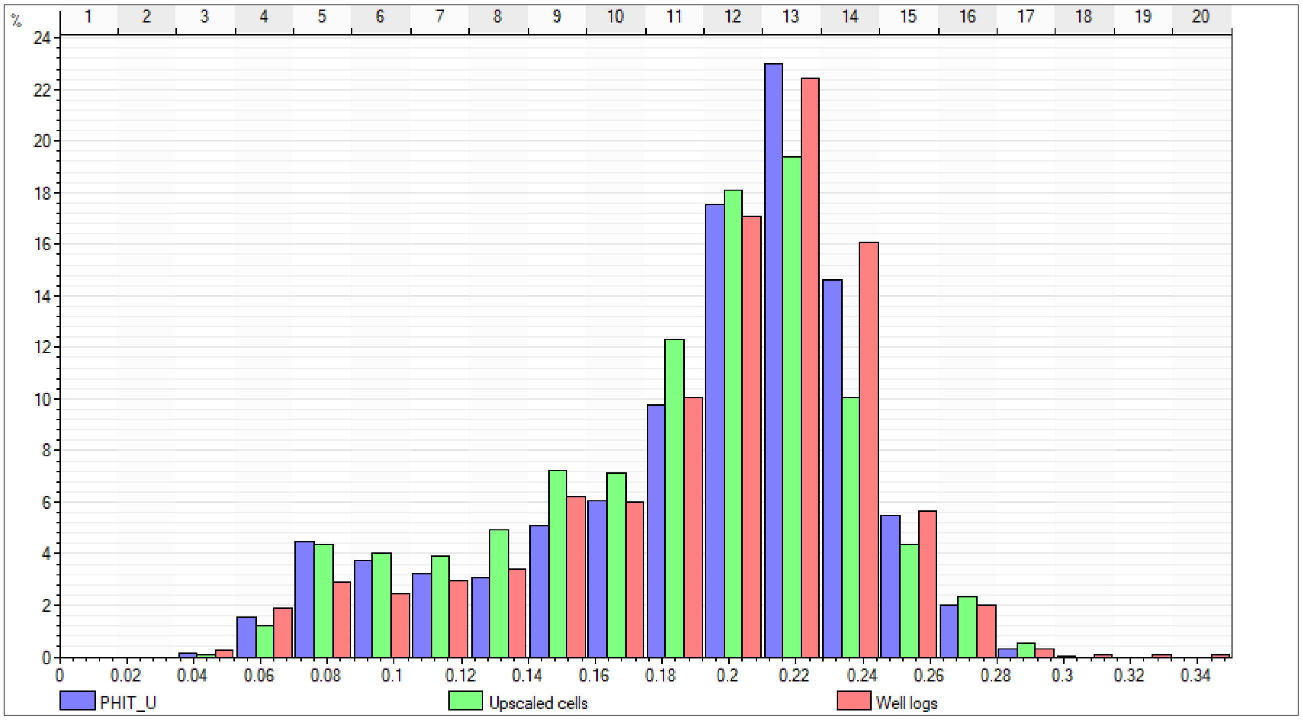


Figure 4-7 – Histogram showing Input Log Data (red) and resulting upscaled property (blue) as a QC of the geological model layering scheme

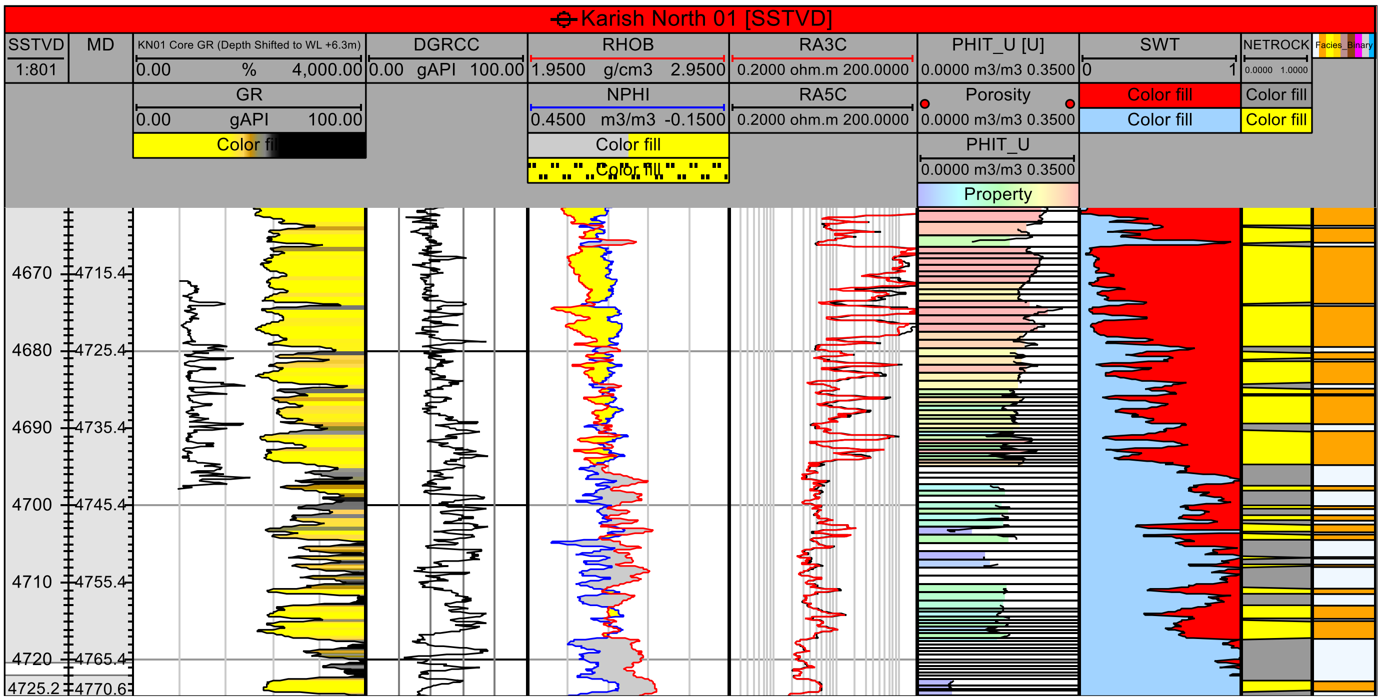


Figure 4-8 – QC of Upscaled Property (solid fill) overlain by calculated Phit (black curve) –Track 5

4.3.5 Gas Water Contact

The Free Water Level (FWL) which is coincident with the GWC has been confirmed at 4512m TVDSS for Karish Main, based on excellent formation pressure data in Karish-1 and Karish Main 02. The Karish Main water leg is approximately 10psi overpressured relative to the regional aquifer

The Karish North FWL is interpreted at 4791m TVDSS, some 279m deeper than the Karish Main GWC. The FWL is defined by the Karish North 01 ST03 LWD pressure data, with a GR correlation pass being used to correct LWD pipe depth under tension to LWD depth pipe under compression. The Karish North 01 well LWD and wireline depths have then been used to correct Karish North 01 ST03 pipe depth (compression) to wireline depth, giving a FWL/GWC at 4791m TVDSS

Based on the Karish North 01 ST03 formation pressures, the Karish North C sands are 57psi overpressured relative to the Levantine regional aquifer pressure. The D sands are approximately 85psi overpressured. The mechanism by which the Karish North accumulation is overpressured relative to the regional aquifer pressure is poorly understood. Structural compartmentalisation is considered unlikely, whilst contamination of the Karish North and Karish-1 bottom-hole water samples does not allow for accurate identification of salinity differences. The different pressures observed between the Karish North C sands and Karish North D sands can most likely be explained by the relatively small three-way dip closure at Top CD Shale in Karish North acting as a local intra-reservoir seal.

4.4 Facies Model

4.4.1 Facies Log

Given the binary nature of the Karish North 01 and Karish Main 01 core, a simple sand/shale approach has been used to generate a lithology log (facies log) as the input to the facies model.

A Vshale cut-off of >0.4 and total porosity <0.10 has been used to assign shale, with net sand being any values out with the cut-off. This results in a facies model which is consistent with the cored intervals, but which is limited in accuracy by the resolution of the conventional logging tools.

The Tamar B sands across the Karish Main and Karish North structures are thinly bedded in nature, with Halliburton's XRMI showing good evidence for thinly bedded pay below the resolution of conventional tools. Further, this thinly bedded pay which without the benefit of XRMI would be classified as non-net has been proven to be produceable via the KN01 mini-DSTs. In order to capture the thinly bedded pay, Task Fronterra have reprocessed the XRMI raw data and carried out structural and sedimentological analysis of the resulting image log. A subsequent interpretation of the net sand thickness has been made, resulting in binary low-mid-high case net sand flags. The mid case sand flag has been used to modify the input facies log across the B sand to capture the likely increase in NTG of the thinly bedded B sands.

4.4.2 Upscaling of Facies Log

Upscaling was performed using the 'most of' methodology.

Only those wells with a full penetration of the gas bearing reservoir have been upscaled. The Karish North 01 ST01 well has not been upscaled as its proximity to the Karish North 01 motherbore results in conflicting data.

4.4.3 Methodology

The methodology used for facies modelling is Sequential Indicator Simulation (SIS) with variogram ranges being utilised from bathymetrically unconstrained outer submarine fan deposits (Paleocene) of the Central North Sea.

The geological model presented in the Karish Main and Tanin FDP (2017) used an interpreted TST map per stratigraphic unit as a proxy for net sandstone distribution. This same methodology has not been applied for two reasons: 1) The excellent well control from crest to flank allows excellent control on the facies model. The Karish North 01 well and sidetracks show the Tamar sands to be perfectly correlatable and of consistent thickness over large distances (>700m) and therefore a proxy for net sand distribution is not required. 2) the seismic interpretation does not show string spatial variation in TST away from points of well control in the same way that Karish Main does at A and B sand level.

4.4.4 Facies Proportions

The facies proportions have been defined per zone by the proportions seen in those wells that have been upscaled. It is important to note that the facies proportions have been set as well log scale and not from the upscaled data. Given the relative coarse layering adopted for the geological model within the main reservoir unit (C Sand), using upscaled cells to define facies proportions would result in a facies model that is not consistent with the facies proportions observed in the well data

4.5 Petrophysical Models

4.5.1 Porosity Models

Both a net total and net effective porosity model were generated. The net total porosity has been used for all volumetrics. Both porosity models are constrained by the facies model (Section 4.4). Non-net facies (mudstone) have been modelled with zero porosity. A later dynamic sensitivity to porous and therefore permeable mudstones will be run.

4.5.2 Petrophysical Log Editing

The generated facies logs (Section 4.4.1) are essentially a binary product with net and non-net reservoir. Prior to upscaling the input CPIs into the geological model, porosity values (both total and effective) within the non-net facies (Facies Code 0) were unassigned (nulled). The output of the geological model should be net total porosity and net effective porosity, given the facies model and subsequent net to gross model remove any bulk volume associated with non-net facies.

This was achieved in the well log calculator using:

PHIE = if (Facies=1, PHIE, if (Facies<1, u, PHIE))

PHIE = if (Facies=1, PHIT, if (Facies<1, u, PHIT))

4.5.3 Upscaling of Porosity Logs

The porosity logs have been upscaled arithmetically as line data with a bias to facies.

Only those wells with a full penetration of the gas bearing reservoir have been upscaled. The Karish North 01 ST01 well has not been upscaled as its proximity to the Karish North 01 motherbore results in conflicting data. Upscaling the Karish North 01 ST01 well data would have resulted in a more optimistic porosity model, with the calculated net porosity being higher in KN01 ST01 than the KN01 motherbore. The discrepancy in the porosity values of these two wells is still being resolved, but is thought in part, to be due to unreliable density measurements in KN01 ST01.

4.5.4 Data Analysis

Data Analysis for the net effective and net total porosity models consisted of defining the distribution for the normal score transform for the net sand facies (Facies Code 1) per zone. Importantly the distributions were set to match the porosity range, mode and distribution of the input data at well logs scale, rather than the default upscaled logs. This ensures that the resulting effective and total porosity models are entirely consistent with the observed porosity in the input dataset and are not homogenous due to the significant upscaling (**Figure 4-9**).

Incorporating the thinly bedded B sands into the petrophysical model is problematic, owing to a lack of data, due to log resolution limitations. To model porosity in the thinly bedded B sands, the data analysis and resulting distribution of Lower C sand net reservoir has been used to model the B sands that are identified on the XRMI log and not triple combo. Whilst the Lower C sand reservoir is lower quality than the Upper C sands, and therefore this approach could be deemed pessimistic, the Lower C sand bed thickness and conceptual depositional environment (marginal, off-axis turbidite sheet sands) is most analogous to the B sand conceptual model.

4.5.5 Net Total Porosity Property

The property modelling for net total porosity was carried out for both Karish and Tanin using Gaussian Random Function Simulation, using the same variogram settings and seed points as the facies models, resulting in a net total porosity model that is entirely consistent with the facies model. The porosity values for non-net facies (Facies Code 0) were set as zero. The average net total porosity distribution is shown in **Figure 4-9**.

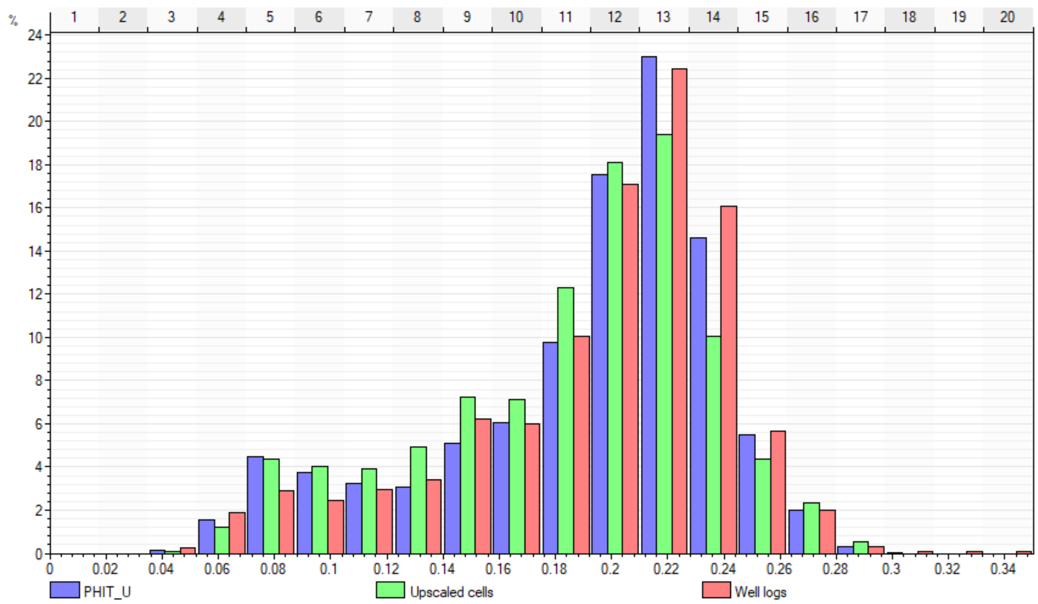


Figure 4-9 – Net Total Porosity Property Distribution

4.5.6 Permeability Model

The Karish North permeability model has been generated using the overburden corrected (0.94) air permeabilities from all available Karish cores i.e., KN01 (Upper C Sand), KM01 (Lower C Sand) and KM02 (Upper C Sand). The Kphi transform has been derived from an exponential line fit of the core data and is described in Section 3.4.9. The transform is used for net reservoir sands in all reservoir units.

No Klinkenberg correction has been used given the reservoir quality, gas slippage in the high quality Tamar sands is considered minimal.

This transform has been applied directly to the net total porosity model (non-net facies assigned zero permeability) using the property calculator. Application of the KPhi transform to the PHIT log and collocated cokriging against the porosity model was not required due to the very high correlation coefficient for the KPhi linear regression.

4.5.7 Water Saturation Model

Direct use of calculated (Archie) Sw in the thinly bedded reservoir (B Sands and Lower C sands) is considered to under-calculate true Sgas. It is considered that the log based water saturations are discounted by bed boundary effects and associated thin bed issues and hence do not give an accurate representation of the hydrocarbon saturation found in the various facies found in Karish North and Karish Main. As a result, a capillary pressure method, combining elements of other data has been generated from the initial Special Core Analysis (SCAL) data from Karish North and Karish Main. This is currently a work in progress, awaiting delivery of the final SCAL data, in particular porous plate data, after delivery of which the after which the water saturation model will be revised.

Based on the available mercury injection capillary pressure data (MICP), a J-Function has been generated (**Figure 4-10**) that can be used with some confidence across the Karish North and Karish Main reservoirs to estimate the true water saturation values present in the cores as determined by routine and special core analysis methods.

Initial data analysis suggests that the overall porosity/permeability relationship is fairly simple and follows an almost linear trend (**Figure 4-11**), which allows for single relationship to be generated. There is also a reasonable correlation between the Dean Stark water saturation values, as well as end point centrifuge capillary pressure water saturation values and permeability (**Figure 4-12**). In addition, the relationship between permeability (**Figure 4-14**), and to a lesser extent porosity (**Figure 4-13**), and water saturation is also fairly simple. This allows for the generation of a simple relationship taking into consideration rock quality to be made from the data available to date.

These methods do not take into consideration height above the FWL, but serve to show where there is a disconnect between log based Sw calculations and direct Sw values generated from various core analysis measurements. This gives confidence that a robust SQRT(K/PHI) relationship to Sw, exists that can be moved forward in a saturation height relationship based on capillary pressure data (MICP initially, and Centrifuge and Porous Plate data subsequently) and also model height above a FWL relationships.

The J-Function used to model Sw for the geological model assumes a water gradient of 0.435psi/ft and a gas gradient of 0.146psi/ft, taken from the Karish North 01/Karish North 01 ST01 RDT data.

Capillary Pressure is calculated using:

Pc = HAFWL (ft) x 0.289

A continuous J log can then be calculated:

J = (Pc / (485 x Cos(140))) x (SQRT(Perm/Poro)

Assuming IFT (mercury-air) = 485 d/cm and Contact Angle (Reservoir) = 140 deg (0.7660).

The equations can then be combined to give

Sw = 10 ^ (A x Log10 ((HAFWL*0.289) / (IFT x Cos(theta)) x (SQRT(Perm/Poro))) B),

From the Karish MICP dataset A = -0.5466 and B = -0.1503

The resulting match to the calculated Sw in the Upper C sands is excellent. As expected, for the Lower C sands and B sands the Saturation Height Function (SHF) derived Sw is lower than the calculated Sw, due to intentional compensation for thin bed effects (**Figure 4-10**). This is evidenced by the delta between SHF derived and calculated Sw in general being lower in the thicker beds.

The water saturation modelling will be revisited once the SCAL data has been received, particularly from the KM01 Lower C sand core. The SHF employed in the current geological model gives a large transition zone for the average porosity class (**Figure 4-15** and

Figure 4-16) than would be expect from a Darcy sand. At time of writing, it is felt that the MICP data yields conservative estimates of hydrocarbon saturations.

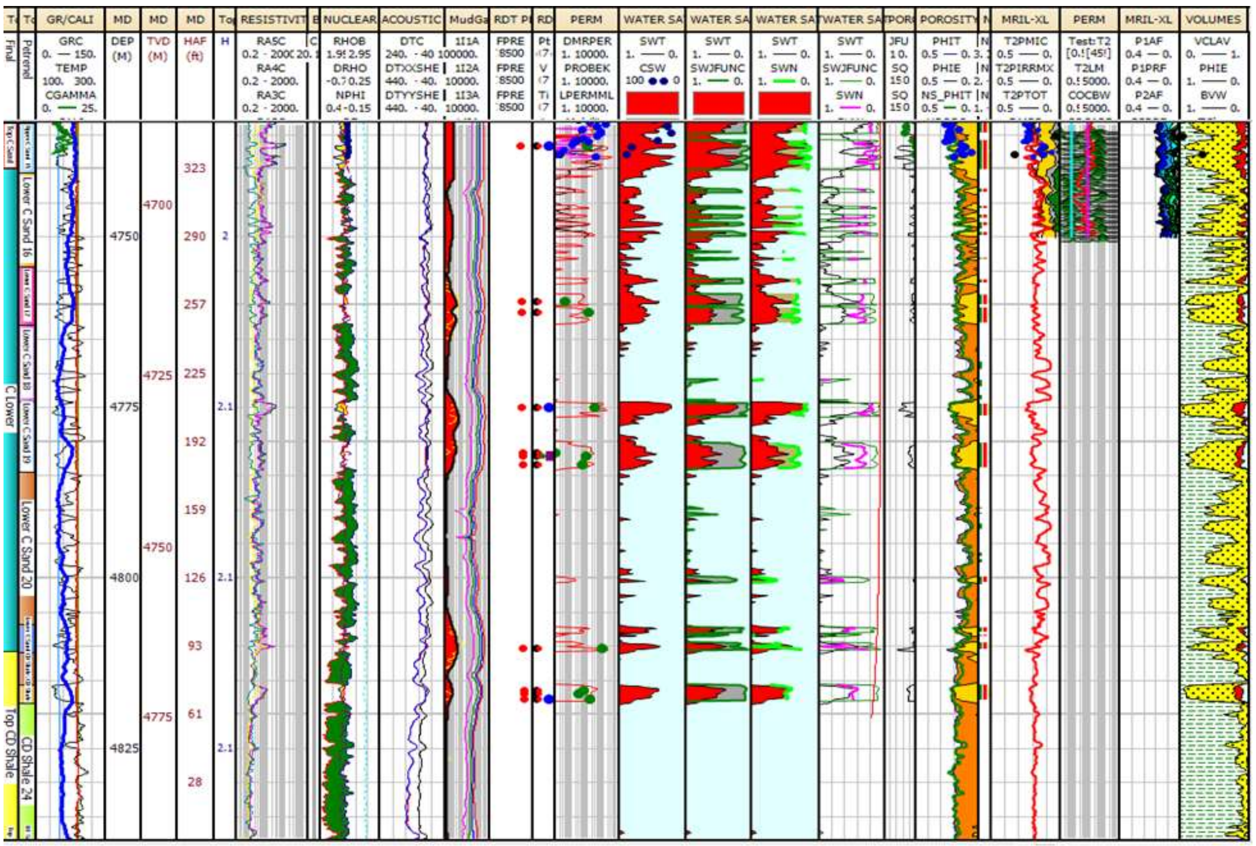


Figure 4-10 – Comparison of Calculated Water Saturation (Swt) and modelled Sw (Swn) from Saturation Height Function

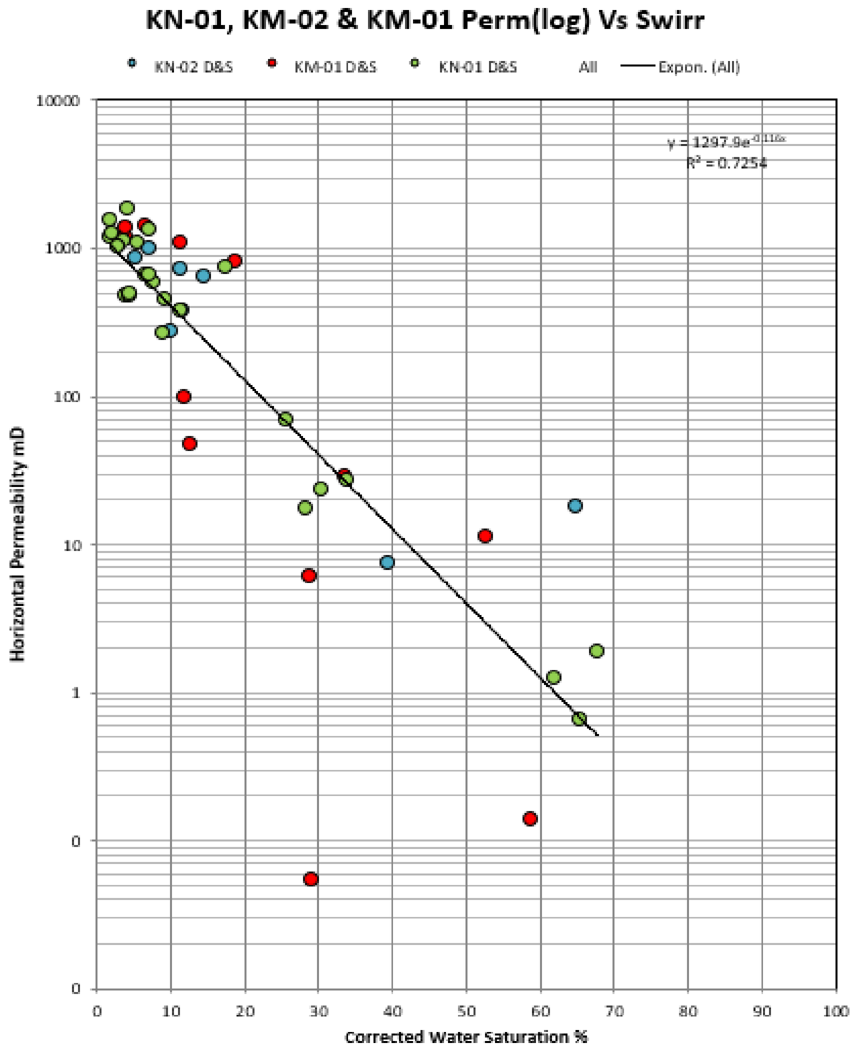


Figure 4-11 – Correlation of Dean Stark water saturation values with Ambient Air Permeability

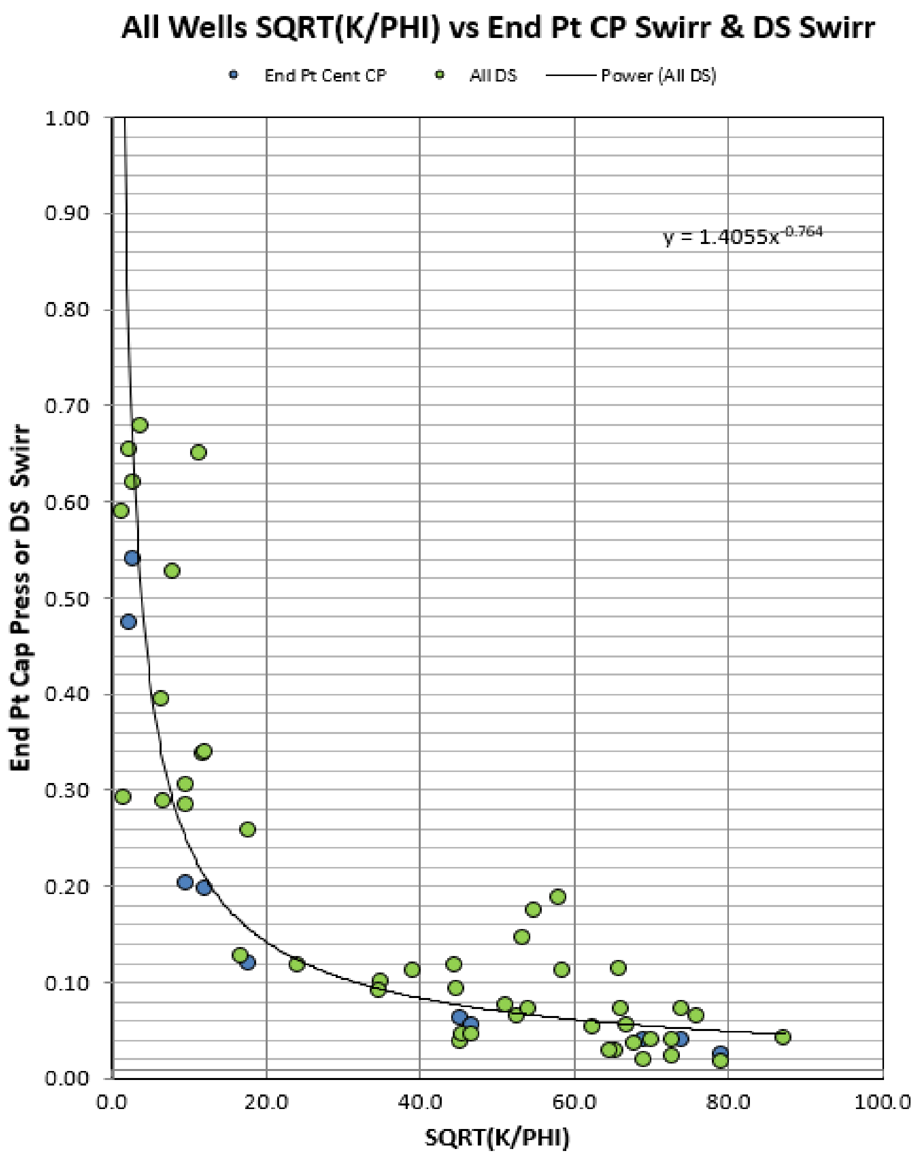


Figure 4-12 – Correlation of end point centrifuge capillary pressure water saturation values and permeability

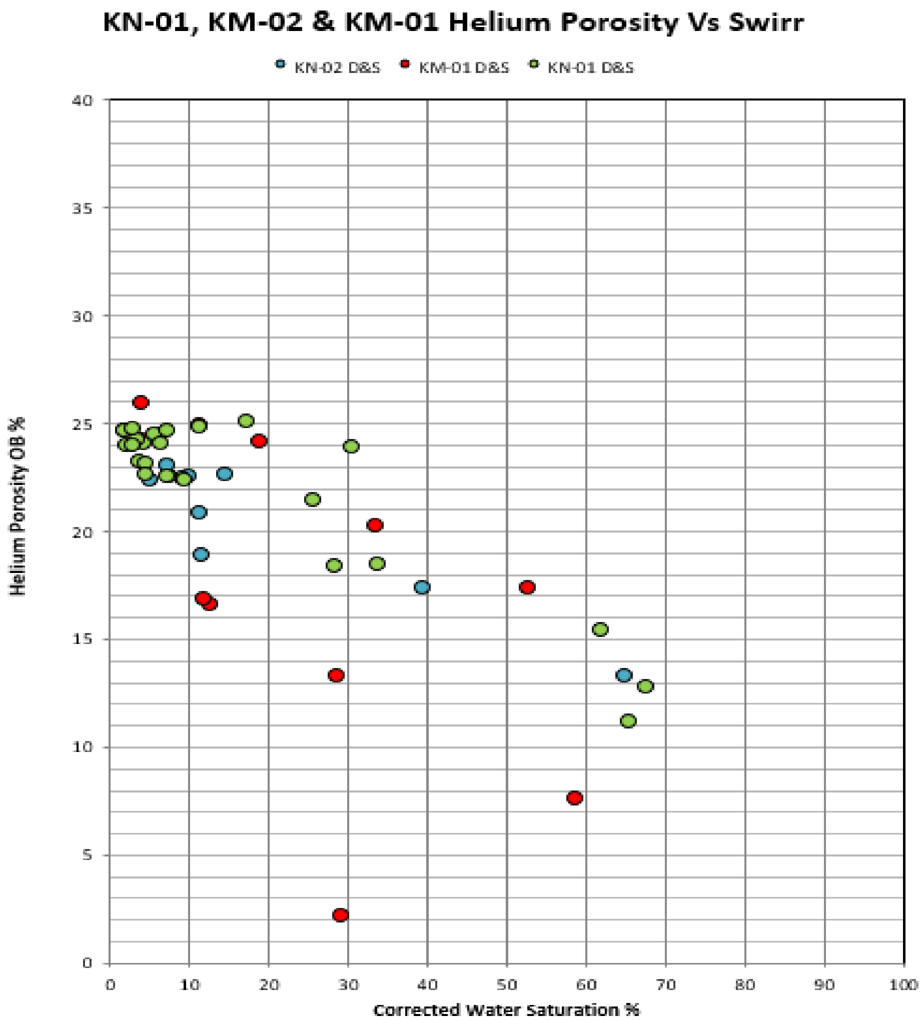


Figure 4-13 – Correlation of Helium Porosity with correct Dean Stark water saturation values

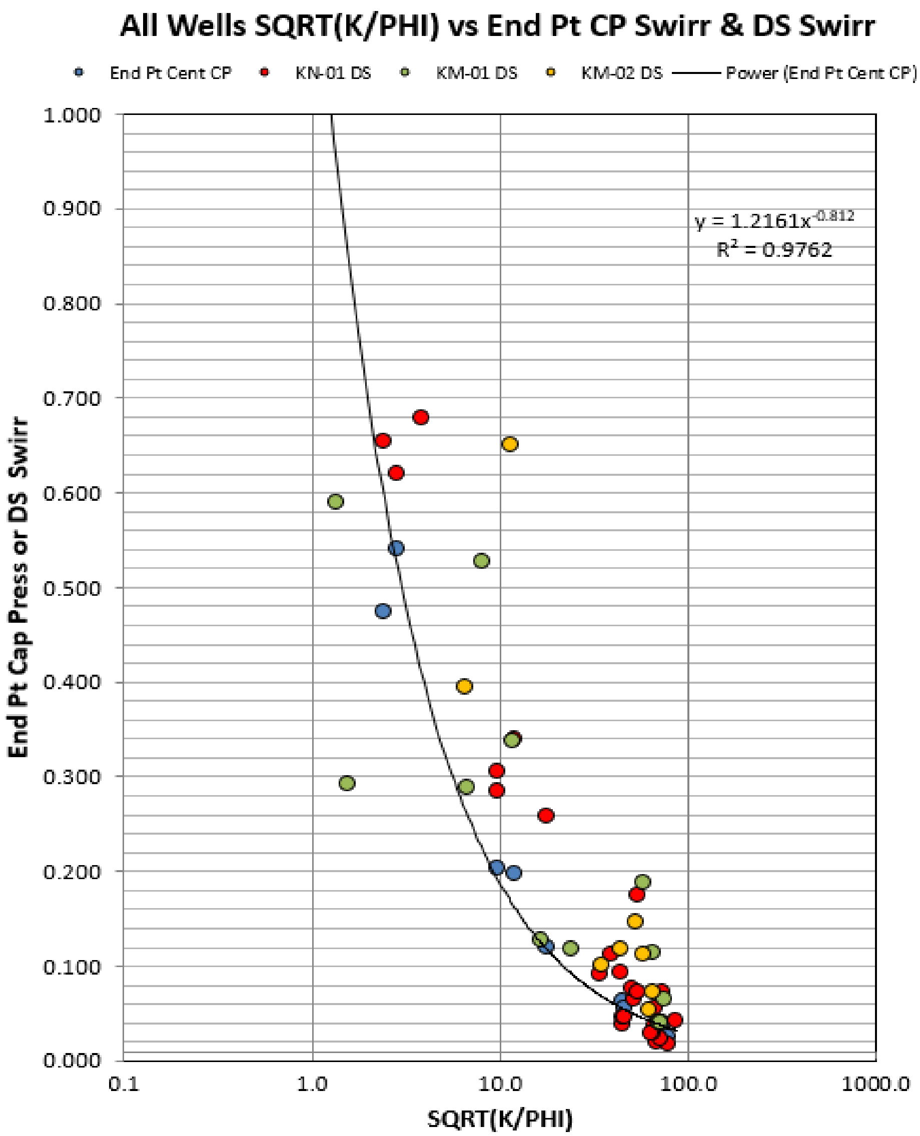


Figure 4-14 – Correlation of Helium Porosity/Permeability with correct Dean Stark water saturation end point centrifuge capillary pressure water saturation

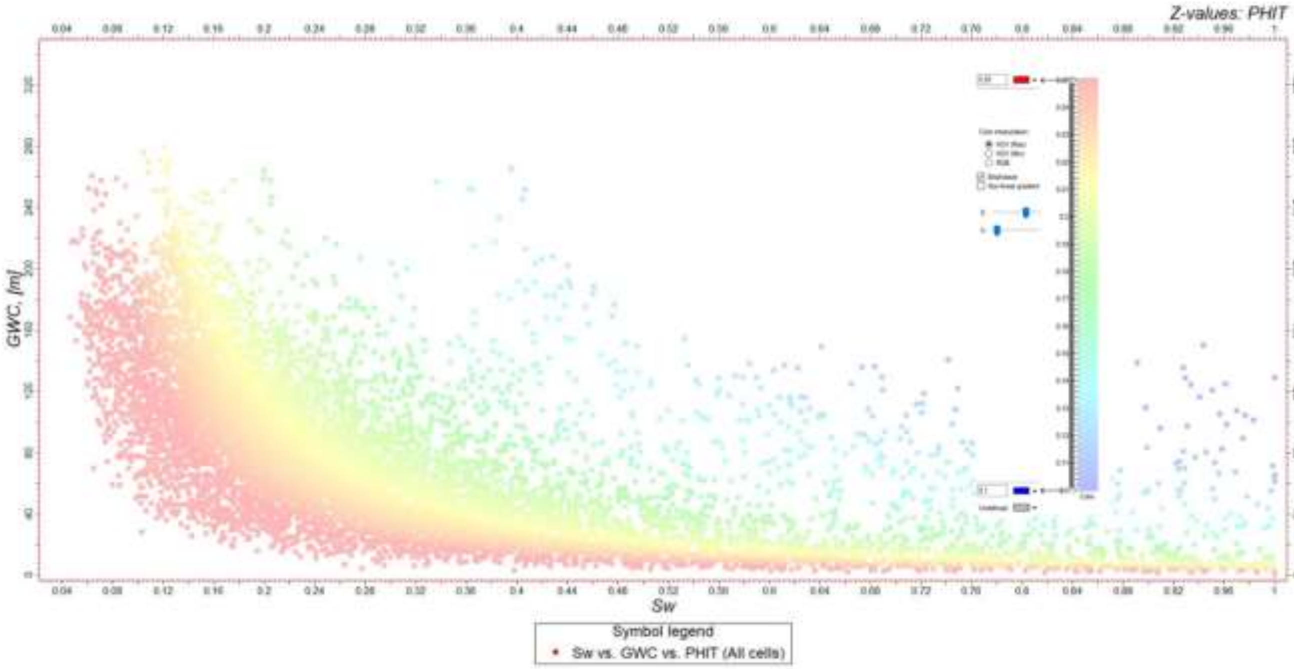


Figure 4-15 – Cross Plot of Sw v Height Above Contact coloured coded by Phit

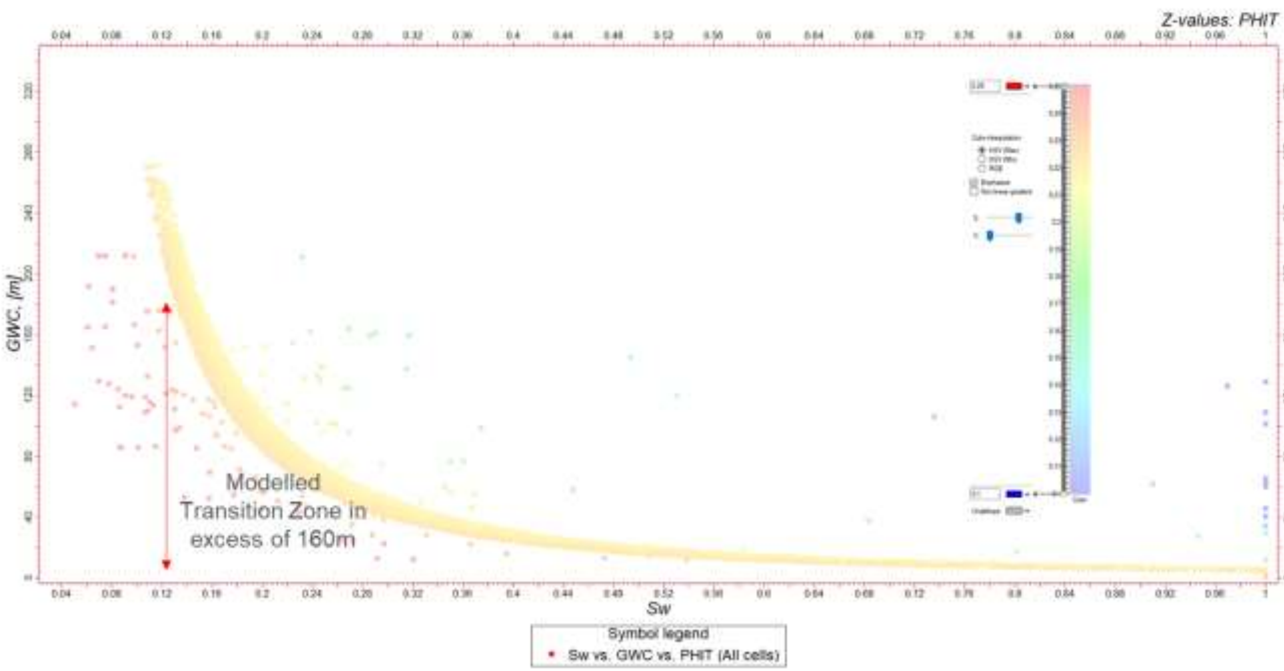


Figure 4-16 – Cross Plot of Sw v Height Above Contact for average porosity class (0.22)

5 Volumetric Assessment

5.1 Summary of Karish North Reference Case Geological Model

Table 5-1 summarises the Gross Rock Volume, petrophysical properties and fluid properties for the Karish North reference case deterministic geological models.

5.1.1 Karish North Reference Case Geological Model

KARISH NORTH					
	GRV	NTG	Net PHIT	Net Sgas	Bg
	MMm^3	Decimal	Decimal	Decimal	SCM/RCM
B Sands	2204	0.155	0.169	0.555	372
C Sands - Upper	705	0.855	0.221	0.727	372
C Sands - Lower	565	0.418	0.170	0.499	372
CD Shale	97	0.197	0.209	0.558	372
D Sands	232	0.371	0.202	0.466	372

Table 5-1: Karish North Reference Case Geological Model Average Petrophysical Properties per structure and per reservoir unit

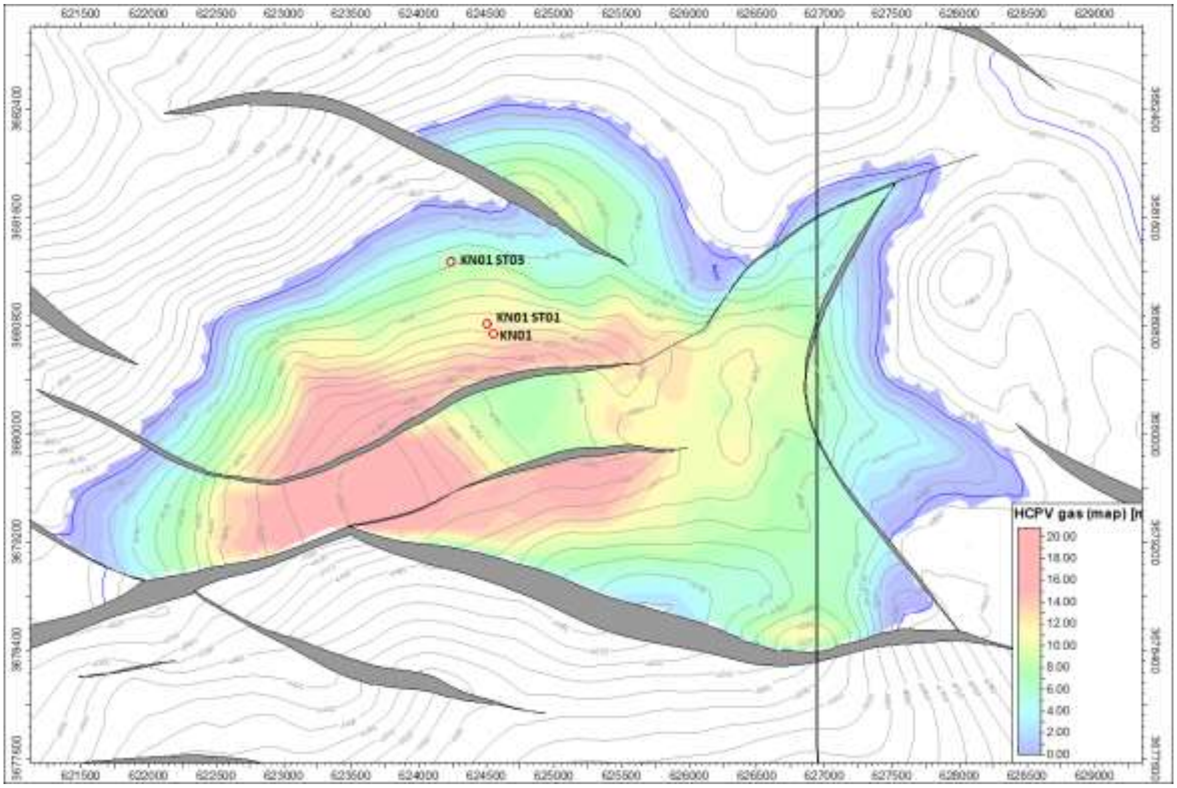


Figure 5-1 – Karish North Reference Case Geological Model Hydrocarbon Pore Thickness Map (m)

KARISH NORTH						
	GRV (MMm³)	Net Volume (MMm³)	Pore Volume (MMm³)	HCPV (MMm³)	GIIP	
					BCM	bscf
B Sands	2204	341	57.8	32.1	11.9	421
C Sands - Upper	705	603	133.2	96.9	36.0	1271
C Sands - Lower	565	236	40.1	20.0	7.5	264
CD Shale	97	19	4.0	2.2	0.8	29
D Sands	232	86	17.3	8.1	3.0	106
Total	3802	1285	252	159	59	2091

Table 5-2: Karish North Reference Case Geological Model In Place Volume per Reservoir Unit

KARISH NORTH		
	GIIP	
	BCM3	bscf
KN North Crest	17.0	601.5
KN North East Crest	3.9	137.7
KN Graben	11.6	409.3
KN West Slope	0.7	25.8
KN East Crest	21.4	757.1
KN East Slope	54.7	159.6
Total	109.4	2091.0

Table 5-3: Karish North Reference Case Geological Model In Place Volume per sub-structure

5.2 Energean In-Place Volumetric Assessment: Probabilistic Range

5.2.1 Methodology

A probabilistic range of geological models has been constructed for Karish North to determine the range of in place volumes within each structure of the field

The models were constructed using the Petrel 2016 workflow manager to write a probabilistic workflow. Some 1300 realisations of the Karish North field were run. This has the advantage over conventional Monte Carlo simulation that any given outcome can be reconstructed, inspected and simulated if required. It also allows the areal distribution of Hydrocarbon Pore Volume to be determined which has many advantages for development well planning.

5.2.2 Karish North Input Parameters

5.2.2.1 Gross Rock Volume

The uncertainty in gross rock volume is well constrained owing three penetrations of the Karish North reservoir from crest (KN01/KN01ST01) and flank (KN01 ST03). Statistical analysis of variations in the seismic velocities was conducted, using the Karish Main wells as further constrained, to give a standard deviation (1std) map of depth uncertainty i.e. uncertainty in depth conversion (

Figure 5-2).

The 1 standard deviation of depth error has been used to probabilistically model variable GRV and capture error in the velocity model. It has been assumed that 3 stds covers the full range of uncertainty, with 66% of the outcomes falling between zero error and 1 standard deviation (+/-)

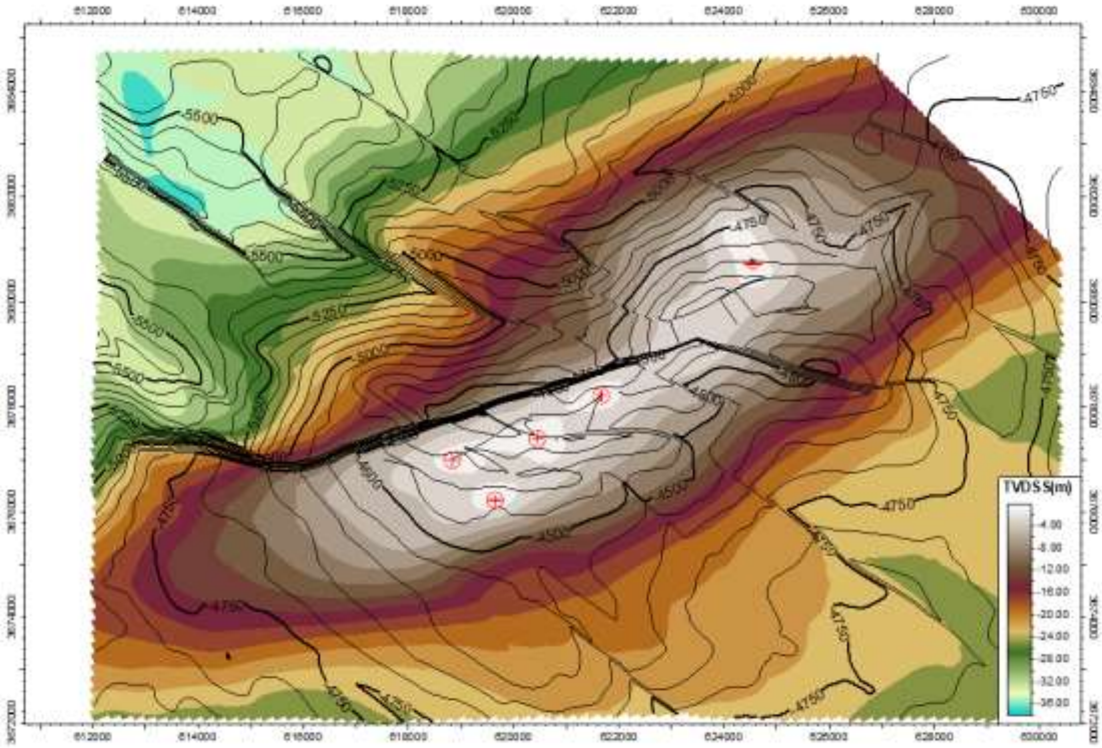


Figure 5-2 – Velocity Model Depth 1 Standard Deviation Error Map

5.2.2.2 Gas Water Contact

5.2.2.2.1 Depth Error in Measurement of Gas Water Contact

The GWC has been determined to be at 4791m TVDSS with little depth error (+/- 5m TVD). This is estimated by looking at the compounded depth error in all the wells where there has been a complete penetration of the hydrocarbon column, namely:

- Karish North 01
- Karish North 01 ST01
- Karish Main 01
- Karish Main 02

These wells all benefit from both WD and Wireline, with both conveyance methods providing useful constraints for the depth uncertainty.

The areas of depth uncertainty that are addressed in the context of the Karish North GWC are:

- Wireline Depth vs. LWD (Pipe) Depth
- Depth error between different wireline runs with different FE tools
- Geodetic (MWD) survey error
- Pipe tally error

- Pipe Under Tension vs. Pipe under Compression Depth

In addition, the results from the analysis are applied to the KN01 ST03 LWD data to address the issue of the Karish North GWC depth uncertainty. For reference, the shift applied to pipe depth (in tension) to wireline depth for the pipe conveyed Geotap data is 3.68m i.e. assumes pipe depth shallow to wireline.

5.2.2.2.1 Sources of Depth Uncertainty

5.2.2.2.1.1 Wireline Depth vs LWD (Pipe) Depth

All of the wells analysed have the benefit of LWD data (pipe conveyed) and a minimum of 3 wireline runs. The depth discrepancy between wire and pipe conveyance is given in Table 5-4

	Reference Depth	Pipe/WL Run 1A	Pipe/WL Run 1B	Pipe/WL Run 1C	Pipe/WL Run 1D	Pipe/WL Run 1E
Karish North 01	Top C Sand	Run1A 0.2 Shallow to LWD	LWD 5.7m shallow	LWD 5.7m shallow	**No GR for RDT**	
	GWC (4791m TVDSS)	Run1A 0.2 Shallow to LWD	LWD 5.2 m shallow	LWD 5.2 m shallow	**See note below**	
Karish North 01 ST01	Top C Sand	LWD 5.2m shallow	LWD 5m shallow	LWD 5.1m shallow		
	GWC (4791m TVDSS)	LWD 5.5 m Shallow	LWD 5.3 m Shallow	LWD 5.15m shallow		
Karish Main 01	Top C Sand	LWD 4m shallow	LWD 4m shallow	LWD 4m shallow	**No GR for RDT**	
	GWC (4512m TVDSS)	LWD 5.2m shallow	LWD 5.2m shallow	LWD 5.2m shallow	**See note below**	
Karish Main 02	Top C Sand	LWD 6.2m shallow	LWD 6.2m shallow	LWD 6.2m shallow	**No GR for RDT**	LWD 6.2m shallow
	GWC (4512m TVDSS)	LWD 6.4m shallow	LWD 6.4m shallow	LWD 6.4m shallow	**See note below**	LWD 6.4m shallow

Notes:
Run 1A AST/XRMI in KN-01 poor depth control, used Run1B as main depth control and subsequently shifted Run1A to be on depth with Run1B
MRIL Run 1C in KN-01 only short section
over C Sand GWC not measured
In KN-01 Run1B used as depth reference
and for KN-01 ST01 tie in
For KN-01, KM-01 and KM-02, RDT runs no GR run, each pre test/sample/mini DST individually located on depth using GR with reference to Run 1B
For KN-01 ST01 a GR log was acquired before RDT testing R1A and used as
depth control, depth correlated to KN-01 Run 1B

Table 5-4: Observed Depth Shifts between Wireline and LWD Depth, Karish Lease, Energean Operated Wells

A number of conclusions can be drawn from comparison of Wireline to Pipe Depth (Table 5-4):

- The maximum absolute TVD error is 6.4m at the GWC in Karish Main 02. Energean believe that the vast majority of the error here is in the LWD error and not Wireline depth error. The Karish-1 discovery well (Noble Energy Operated) found a FWL, defined wireline conveyed RCI at 4512m TVDSS. Karish Main 02 has the benefit of wireline conveyed RDT (Run 1E) which also found the FWL at 4512m TVDSS. Both sets of formation pressures show Karish-1 and Karish Main 2 to be in the same hydraulic compartment. In addition, the recent Karish Main 01 and Karish Main 02 well tests showed no interference between these two wells – indeed a drawdown was seen on the permanent bottomhole gauges in Karish Main 01 whilst Karish Main 02 was on production, demonstrating connectivity (**Figure 5-3**). It should be noted that Karish-1 is in the same Karish Main segment as the Karish-1 discovery well. Therefore, two independent wireline measurements of the FWL, in two wells which are known to be in dynamic communication, have yielded the same estimate of GWC TVD.

- Wireline depth is always deep to LWD across all wells and all runs
- The incremental wireline to pipe error between Top C sand reservoir and the GWC is small (typically <1m)

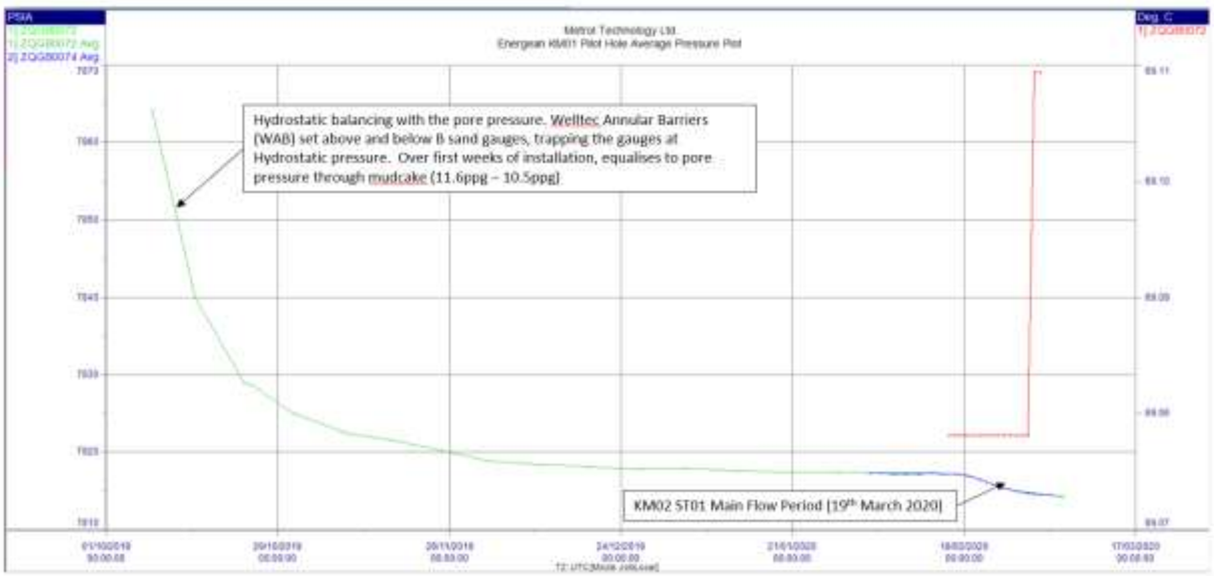


Figure 5-3 – Drawdown on Karish Main 01 permanent wireless gauges (B sands) during Karish Main 02 well test (Upper C sands)

The depth shift (pipe in tension to wireline) that has been applied to KN01 ST03 is 3.68m. Relative to other known depth shifts, in wells with more simple trajectories, this correction is small, and could therefore be considered conservative with respect to TVD of the GWC.

5.2.2.2.1.2 Depth error between different wireline runs with different FE tools

Wireline runs do not give an estimate of TVD, but when using wireline data in combination with MWD data it is important to rule out any MD error.

All tools in any given well were run on the same cable, which rules out any discrepancy being introduced by different rigs or different cables.

The only conceivable remaining error is the degree of cable stretch owing to either 1) the weight of different toolstrings or 2) the different degrees of hold-up due to differing tool geometries.

Table **5-5** shows the difference in WL depth from consecutive runs in the same well.

Karish North 01 wireline Run 1A is spurious in terms of depth, and is known to be such given the consistency between the other 3 wireline runs in this well.

Table 2 demonstrates that with the exception of Karish North 01 WL Run 1A, that the depth error between consecutive wireline runs is <35cm.

5.2.2.2.1.3 Geodetic (MWD) Survey Error

All of the MWD surveys from the Energean operated wells were subject to SAG correction, which accounts for the offset of the pipe relative to the centre of the hole (pipe typically lying on the low side of the well). The SAG correction is small given the wells are low inclination.

In addition to the SAG correction, the final geodetic surveys also correct for pipe stretch. It should also be noted that the KN01, KN01ST01 and KN01ST03 wellbores were all drilled with the same rig, and importantly using the same pipe. Any error in the correction of pipe stretch across all of these wells should be consistent.

Once SAG correction and pipe stretch has been accounted for, it is important to recognise that any TVD depth error in the MWD geodetic survey is equiprobable i.e. the error in TVD is equally likely to be deep as it is to being shallow to reality. This error results from inadequacies in taking surveys at the end of each stand (for Karish North this is every 40m) along with magnetic survey error.

For the Energean wells, Sperry (MWD Service provider) have been asked to provide the Survey Ellipse of Uncertainty (EOU). The Ellipse of Uncertainty concept is shown in **Figure 5-4**. The EOU has 3 values 1) a major axis addressing the major lateral positioning error and the azimuth of the error resulting predominantly from fluctuations in the earth's local magnetic field 2) the minor axis quantifying the smallest lateral error and its azimuth and 3) the vertical error.

For the purpose of this document, the vertical error is the only dimension of interest. The vertical error quoted in the EOU is the vertical error to 2 standard deviations (95%) confidence, assuming a normal distribution with the mean/mode being zero. Being a normal distribution, the vertical error in the EOU (i.e. TVD) is equally likely to be a positive or negative value. That is to say, the survey is as likely to predict true depth as shallow as it is to predict true depth as deep.

	Reference Depth	WL Run 1A/WL Run 1B	WL Run 1A/WL Run 1C	WL Run 1A/WL Run 1D	WL Run 1A/ WL Run 1E	WL Run 1B/ WL Run 1C	WL Run 1B/ WL Run 1D	WL Run 1B/ WL Run 1E	WL Run 1C/ WL Run 1D	WL Run 1C/ WL Run 1E	WL Run 1D/ WL Run 1E
Karish North 01	Top C Sand	R1A 6.1m shallow to R1B	R1A 6.1m shallow to R1C	No GR for RDT		On depth	No GR for RDT		No GR for RDT		
	GWC (4791m TVDSS)	R1A 5.7m shallow to R1B	R1A 5.7m shallow to R1C	See note below		On depth	See note below		See note below		
Karish North 01 ST01	Top C Sand	Run1B 0.2m Shallow	Run1C 0.1m shallow			Run1B 0.2m Shallow					
	GWC (4791m TVDSS)	Run1B 0.2m Shallow	Run1C 0.35m shallow			Run1B 0.2m Shallow					
Karish Main 01	Top C Sand	On depth	On depth	No GR for RDT		On depth	No GR for RDT		No GR for RDT		
	GWC (4512m TVDSS)	On depth	On depth	See note below		On depth	See note below		See note below		
Karish Main 02	Top C Sand	On depth	On depth	No GR for RDT	On depth	On depth	No GR for RDT	On depth	No GR for RDT	On depth	No GR for RDT
	GWC (4512m TVDSS)	On depth	On depth	See note below	On depth	On depth	See note below	On depth	See note below	On depth	See note below

Notes:

Run 1A AST/XRMI in KN-01 poor depth control, used Run1B as main depth control and subsequently shifted Run1A to be on depth with Run1B

MRIL Run 1C in KN-01 only short section over C Sand GWC not measured

In KN-01 Run1B used as depth reference and for KN-01 ST01 tie in

For KN-01, KM-01 and KM-02, RDT runs no GR run, each pre test/sample/mini DST individually located on depth using GR with reference to Run 1B

For KN-01 ST01 a GR log was acquired before RDT testing R1A and used as depth control, depth correlated to KN-01 Run 1B

Table 5-5: Observed Depth Shifts between consecutive Wireline runs in the same well, Karish Lease, Energean Operated Well

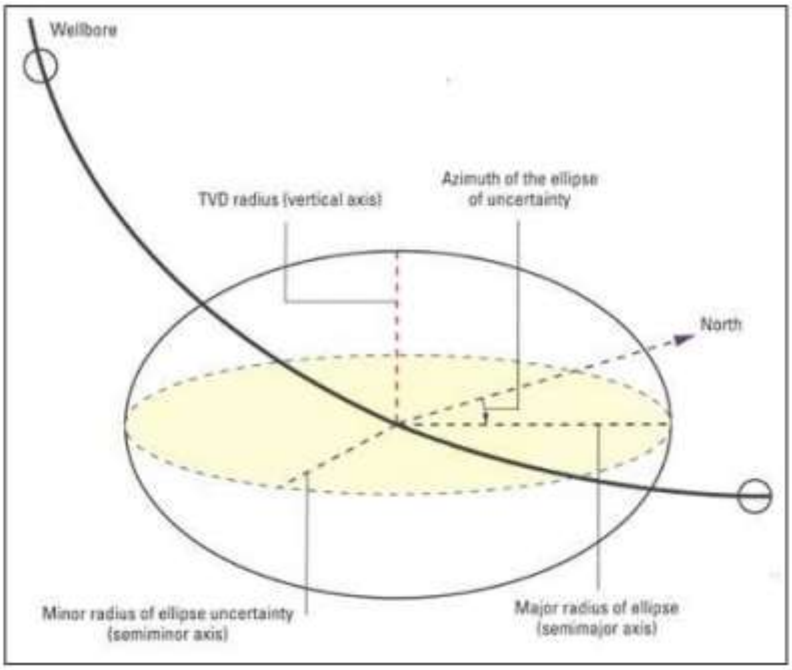


Figure 5-4 – Ellipse of Uncertainty Concept for MWD Surveys

This is an important concept, because if we wish to introduce depth error into data by way of geodetic survey error, it is only technically robust if we introduce a range of depth errors centred around the best technical case. Energean consider the best technical case for the KN01 ST03 case to be 4791m TVDSS. If we wish to introduce a depth error associated with the MWD survey for the purpose, then it is of paramount importance that we model a normal distribution with a mean GWC of 4791m TVDSS.

For the purpose of running probabilistic volumes to generate P10-P90 estimate (80 percentiles), one standard deviation is used as the end member i.e. 68% (68 percentiles) of confidence.

	EOU (vertical metres) at Top 4791m TVDSS	
	1σ	**2σ**
Karish North 01	6.87	13.74
Karish North 01 ST01	6.75	13.49
Karish North ST03	6.76	13.51

Table 5-6: Karish North Wells Ellipse of Uncertainty Vertical Error from KB to 4791m TVDSS (GWC)

It should also be considered that the depth error to just below 13.3/8" shoe in all wells is the same, given that all wells were drilled as sidetracks from the Karish North 01 motherbore, with kick-off depths below 3702m MD. When defining the depth error in the data, the aim should be to quantify the uncertainty in the hydrocarbon column across the Karish North structure. It is therefore proposed, that instead of using the 1.std values from Table 5-6, what should be considered as the uncertainty in the hydrocarbon column thickness (~ GWC uncertainty) is the residual error in the well below the kick-off point, the shallowest of which was 3702m MDBRT. These values are shown in Table 5-7.

	EOU (vertical metres) at Top 3702m TVDSS		EOU (vertical metres) at Top 4791m TVDSS		Residual Vertical Depth Error @ 4791m TVDSS	
	1σ	**2σ**	**1σ**	**2σ**	**1σ**	**2σ**
Karish North 01	4.67	9.33	6.87	13.74	2.21	4.41
Karish North 01 ST01	4.67	9.33	6.75	13.49	2.08	4.16
Karish North ST03	4.67	9.33	6.76	13.51	2.09	4.18

The depth error modelled on the GWC was 4791m TVDSS +/- 2.2m.

Table 5-7: Karish North Wells Residual Vertical Error from K/O Depth to 4791m TVDSS (GWC)

5.2.2.2.1.4 Pipe Tally Error

To rule out any possibility of pipe tally error, an exercise was undertaken to correlate arbitrary GR markers at the kick-off depth of each of the sidetracks to check for consistency between the motherbore and resulting sidetracks. Correlation of arbitrary markers at ~ equal TVD confirms that there is no pipe tally error.

The correlation of KN01 ST01 to KN01 is shown in **Figure 5-5**. To confirm no pipe tally error in KN01 ST03, the correlation of KN01 to KN01 ST02 needs to be confirmed and then the correlation of KN01 ST02 to KN01 ST03 (**Figure 5-7**), given KN01 ST03 was a sidetrack from KN01 ST02 (sidetrack around fish).

No issue was found with the pipe tally – this can therefore be ruled out as a possible source of TVD error.

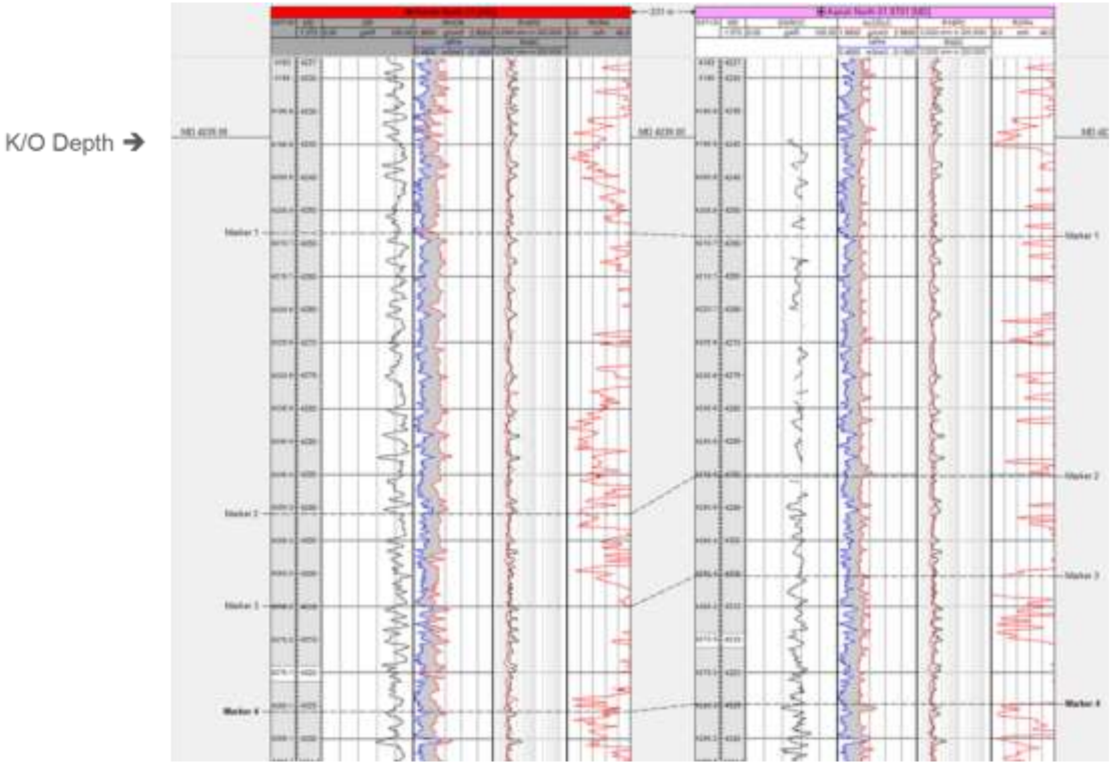


Figure 5-5 – KN01/KN01 ST01 Arbitrary Correlation of GR Markers at K/O Depth of 4239m MDBRT

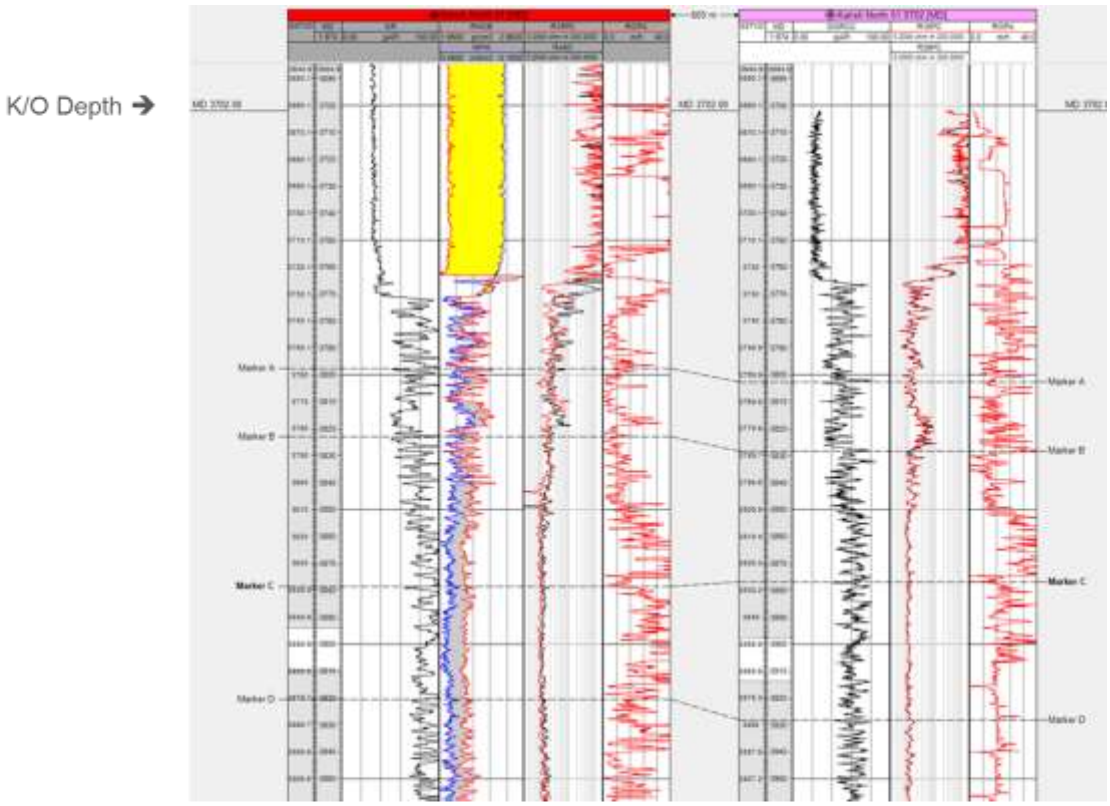


Figure 5-6 – KN01/KN01 ST02 Arbitrary Correlation of GR Markers at K/O Depth of 3702m MDBRT

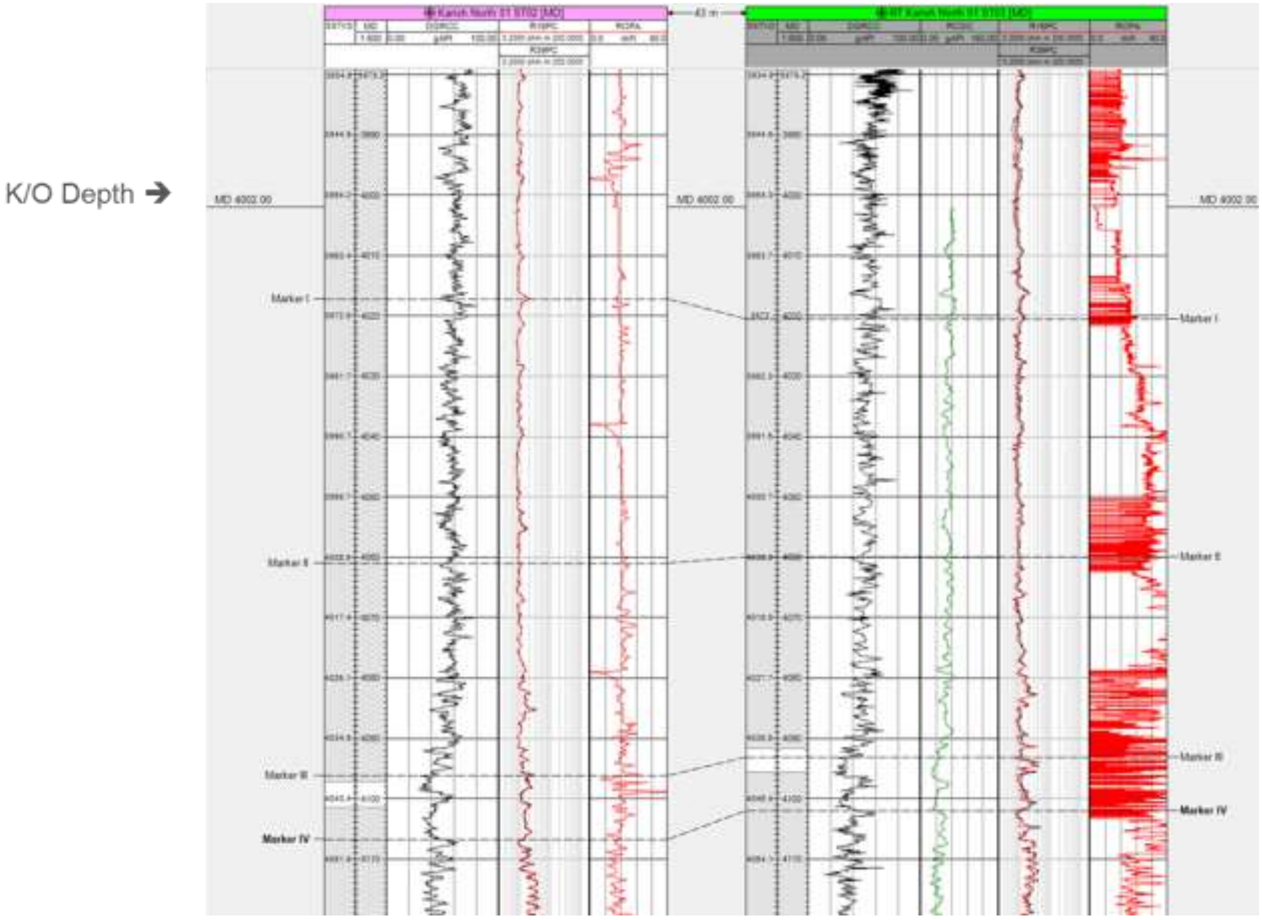


Figure 5-7 – KN01 ST02/KN01 ST03 Arbitrary Correlation of GR Markers at K/O Depth of 4002m MDBRT

5.2.2.2.1.5 Pipe Under Tension vs. Pipe under Compression Depth

The main objective of the Karish North 01 ST03 well was to confirm the depth of the GWC, given KN01 and KN01 ST01 only found GDTs. A velocity model could not be constructed that could explain the proven Karish North seismic DHI at 4780m TVDSS. The KN01 and KN01 ST01 GDT could not therefore be coincident with the GWC.

Due to the KN01 ST03 trajectory being unfavourable for wireline conveyance, Sperry's GeoTap tool was used to record Formation Pressures.

The KN01 ST03 well was drilled to TD, with Gamma Ray and Resistivity. During this period, the drill pipe was in compression. At final TD, a 20m correlation pass (GR) was conducted (logging up) to quantify the depth error between the pipe in compression (logging down) and pipe in tension (logging up). This was important to quantify as the GeoTap pressures were taken with the pipe in tension. The GR pass therefore ensured that 1) the depth of pressure station was known and 2) better quality sands could be targeted for reliable pretests. The difference in depth (**Figure 5-8** and **Figure 5-9**) was found to be 2.2m (tension being deep to compression).

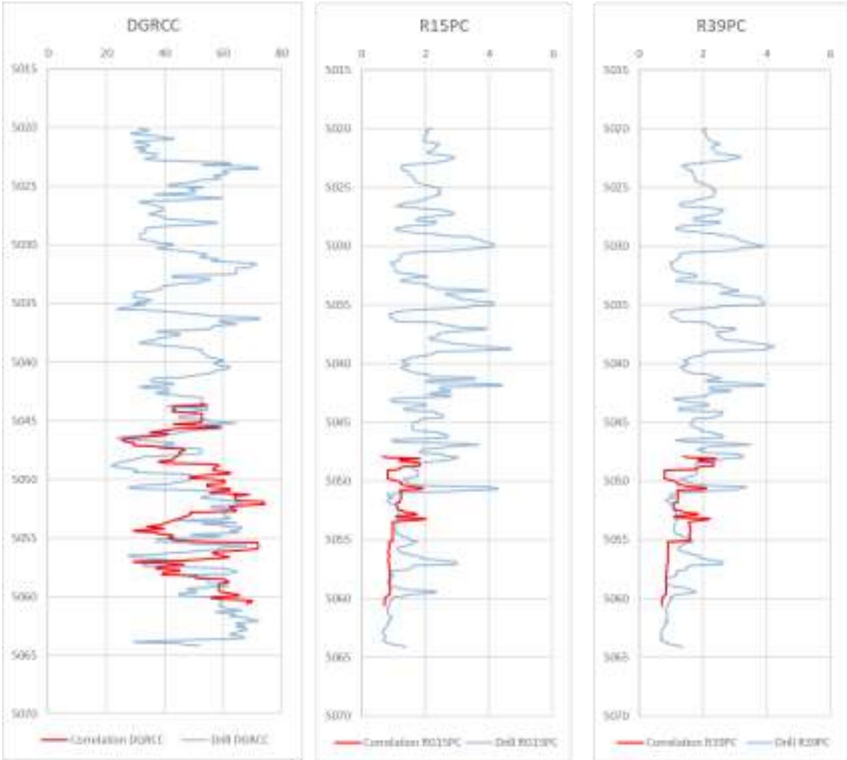


Figure 5-8 – GR with pipe in compression (blue track – logging down) overlain by GR from pipe in tension (red track – logging up). No depth shift applied

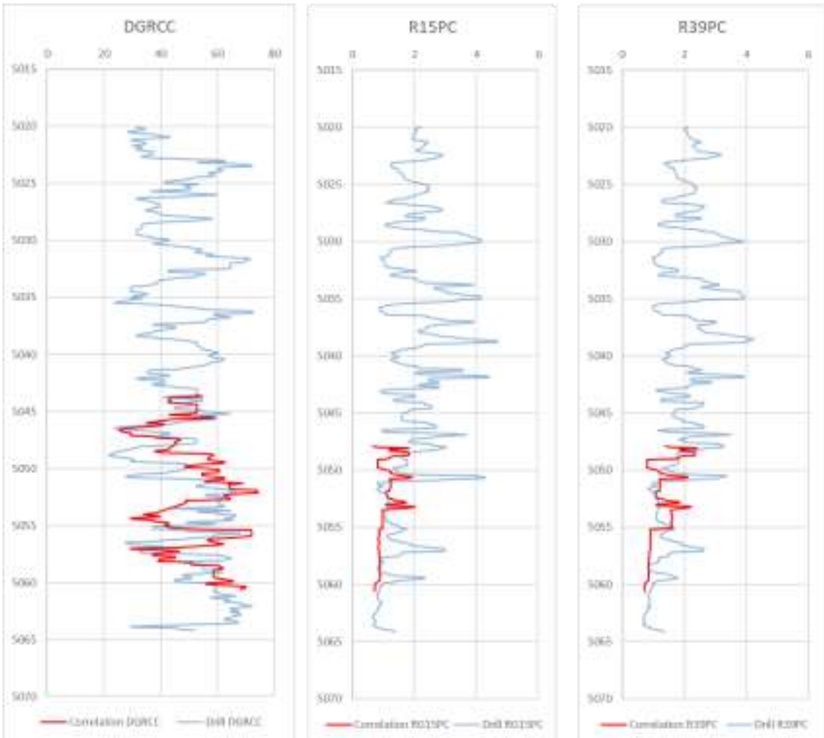


Figure 5-9 – GR with pipe in compression (blue track – logging down) overlain by GR from pipe in tension (red track – logging up). 2.2m depth shift applied to correlation pass

5.2.2.2.2 GWC Depth Error Conclusions

Given the excellent reservoir quality, the Karish north GWC is considered to be coincident with the FWL.

When considering the Karish North FWL (KN01 ST03), it is important to correct the pipe depth in tension to pipe depth in compression. Therefore, the GeoTap formation pressure TVD needs to be moved 2.2m shallower.

Further, to correct pipe depth to Wireline depth to be consistent with the depth reference (KN01 Run 1B), the data needs to be shifted 5.68m deeper (Table 5-4). Therefore, the correction that needs to be applied to the GeoTap depths (pipe conveyed) and the resulting FWL (4787.5m TVDSS) is 3.48m (5.68m minus 2.2m). Therefore, the wireline depth of the FWL in Karish North is 4791.0m TVDSS.

The remaining sources of error are:

- Wireline Depth vs. LWD (Pipe) Depth
- Depth error between different wireline runs with different FE tools
- Geodetic (MWD) survey error
- Pipe tally error

Wireline Depth to Pipe Depth has been shown to be a maximum of 6.4m. The assumption used for KN01 ST03 wireline depth is 5.68m relative to pipe in compression. In all cases, across all wells, the WL depth has always been shown to be deep to pipe depth. The smallest difference between wire and pipe depth is 4.0m (Table 5-4). With the KN01 ST03 FWL being recorded on pipe (tension) at 4787.5m, and therefore 4785.3m (pipe compression), and the minimum WL to pipe correction being 4.0m, the shallowest possible GWC for Karish North is 4789.3m TVDSS (wireline depth). This is only 1.7m shallower than Energean carry as the base case. Employing the maximum wireline to pipe depth shift (6.4m), the GWC could be at 4791.9m TVDSS.

The maximum depth error between different wireline runs with different FE tools has been shown to be 0.35m. This error is so small, it is suggested that this is not considered in defining the possible range of GWCs.

The Geodetic (MWD) survey error should be considered from the kick-off points of the wells. The Karish North well dataset has a significant advantage of having an entirely consistent depth error to at least 3702m MDBRT, and therefore any depth error between the Karish North wells (KN01/KN01ST01/KN01ST03) is the residual MWD error from the kick-off point the GWC. 1std of the error has been demonstrated to be +/-2.2m TVDSS. This would result in a GWC range of 4788.8-4793.2 mTVDSS, centred around the best technical case of 4791m TVDSS.

No Pipe Tally Error has been proven.

5.2.2.2.3 Robustness of the Karish North GWC Interpretation

The Karish North RDT/Geotap Dataset is excellent data showing repeatable fluid gradients (**Figure 5-10**). The plot shown in **Figure 5-10** has been depth shifted by 3.68m to wireline depth. The single pressure taken in the CD Shale is entirely consistent with the CD Shale and D sand pressure points acquired in KN01 ST01 (20 psi overpressured relative to C sands). This therefore provides a good QC that the pressure data from the GeoTap is reasonable. Further, the repeatability of all fluid gradients provides further QC of the data. Sands within the CD Shale have also been shown to be isolated from the C sands, and therefore can explain water recovery from the KN01 ST01 CD shale, whether that be formation water or water based mud.

Given the complete lack of any hydraulic barriers e.g. faults between KN01, KN01 ST01 and KN01 ST03, the tramline geology (

Figure 5-11) and the very high correlatability of the Tamar sands, KN01 ST03 is without doubt in the same hydraulic unit as KN01. The FWL identified on the GeoTap data is therefore the same FWL/GWC as in KN01.

The only remaining discussion point with respect to the GeoTap data is the absolute measure of pressure. Whilst the gauge accuracy in both the GeoTap and RDT is <1psi, the logging environment has to be considered. The GeoTap is acquired with the mud pumps on. The logging environment is dynamic, with the circulation imposing an ECD and therefore an increase effective mud weight on the formation – due to continued circulation the mudcake with not be broken down during the pretest to the same degree as the RDT pretests. It is therefore entirely reasonable that an elevated formation pressure can be expected.

Given the good evidence that KN01, KN01 ST01 and KN01 ST03 are in the same pressure compartment, a small (4psi) correction can be made to the GeoTap data to correct GeoTap to RDT (**Figure 5-12**). It should be noted that by correcting formation pressures by a uniform value, the intercept of the fluid gradient is unchanged in terms of TVDSS, and therefore the interpretation of the GWC depth is unchanged .

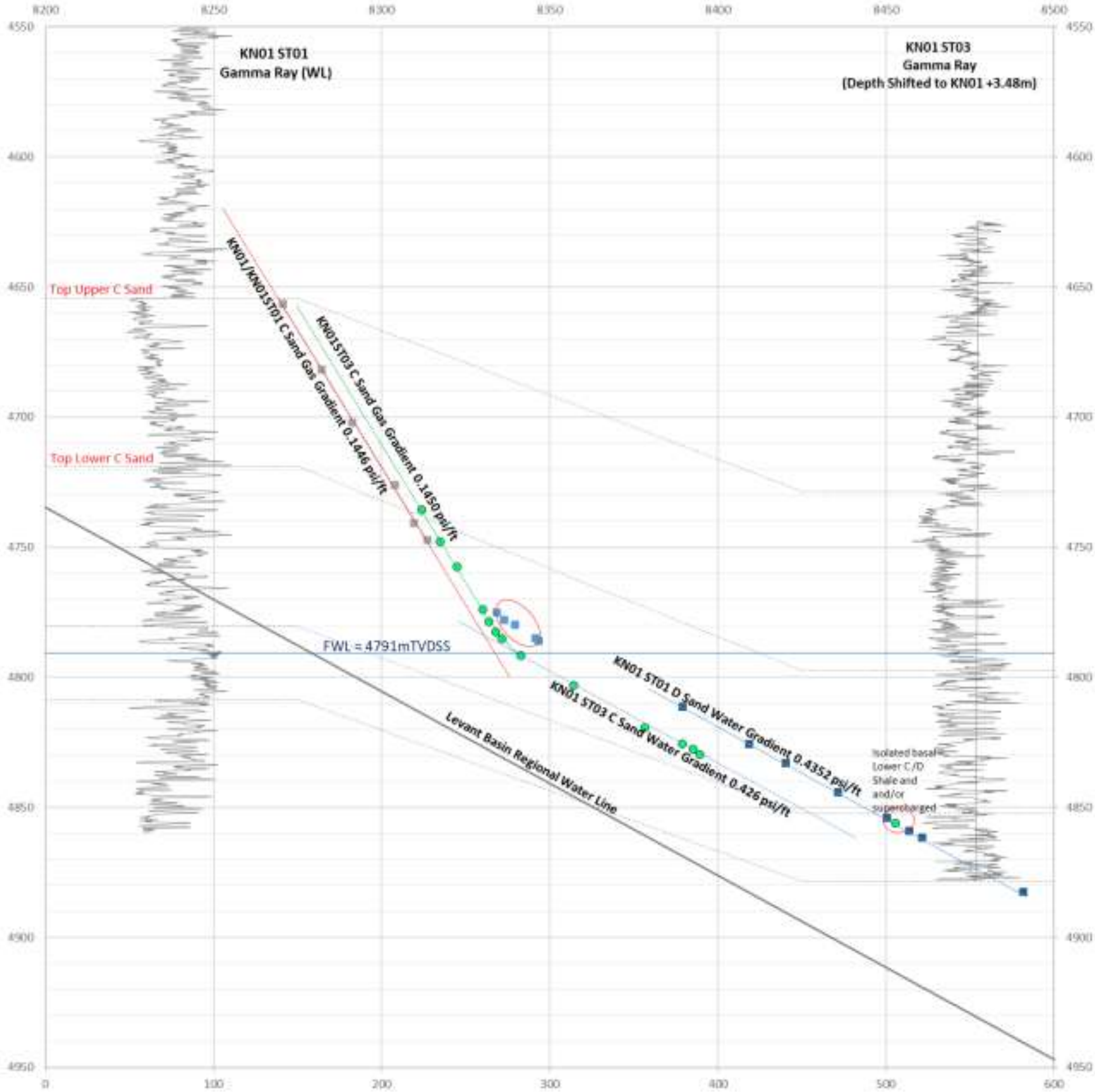


Figure 5-10 – KN01/KN01 ST01 RDT Formation Pressures at recorded (WL) depth. KN01 ST03 corrected to WL depth. GWC interpreted at 4791m TVDSS (C Sands)

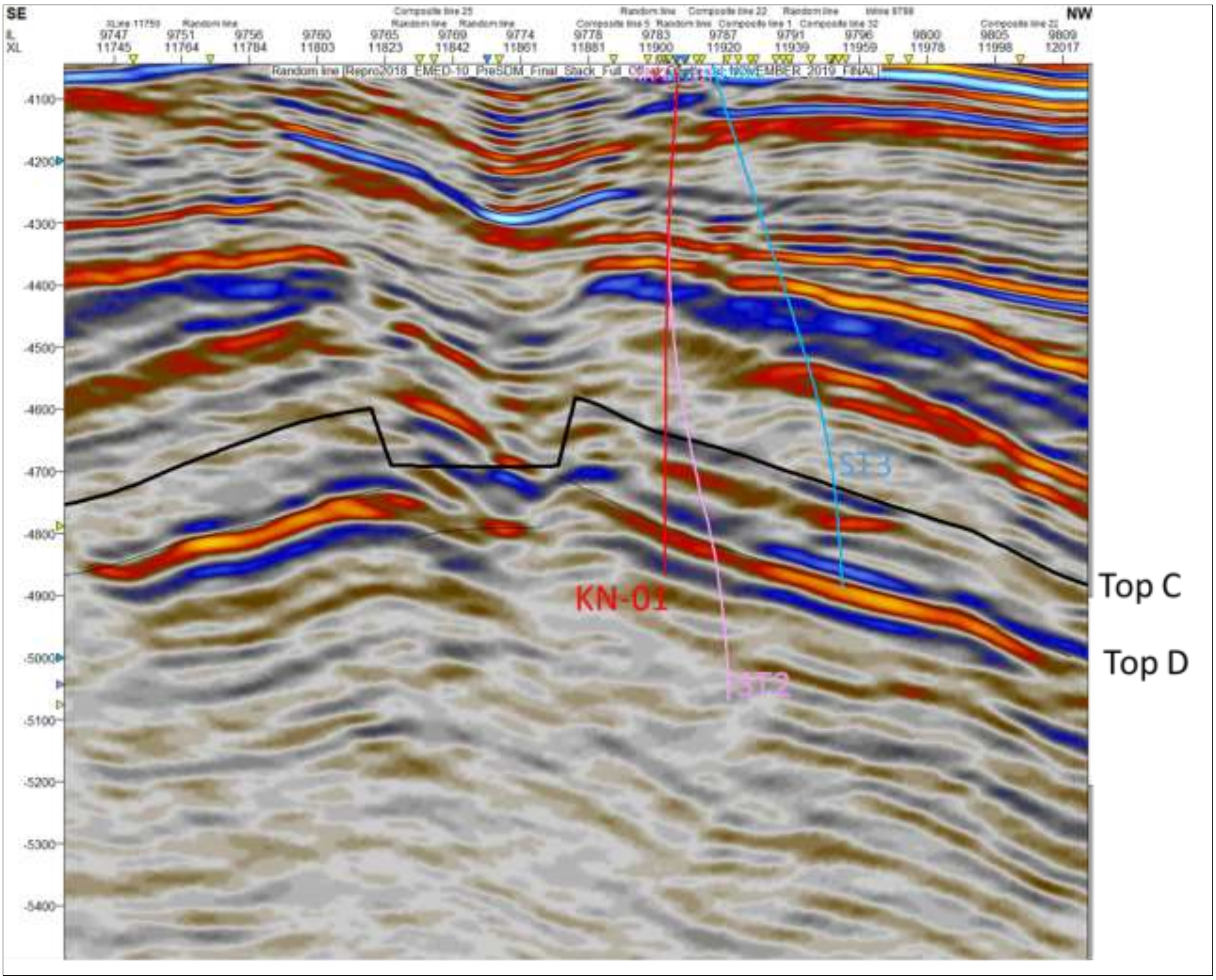


Figure 5-11 – Seismic Section through Karish North 01 and Karish North ST03 showing no apparent faulting and tramline geology, supported by high confidence correlation of Tamar Sandstone FE log

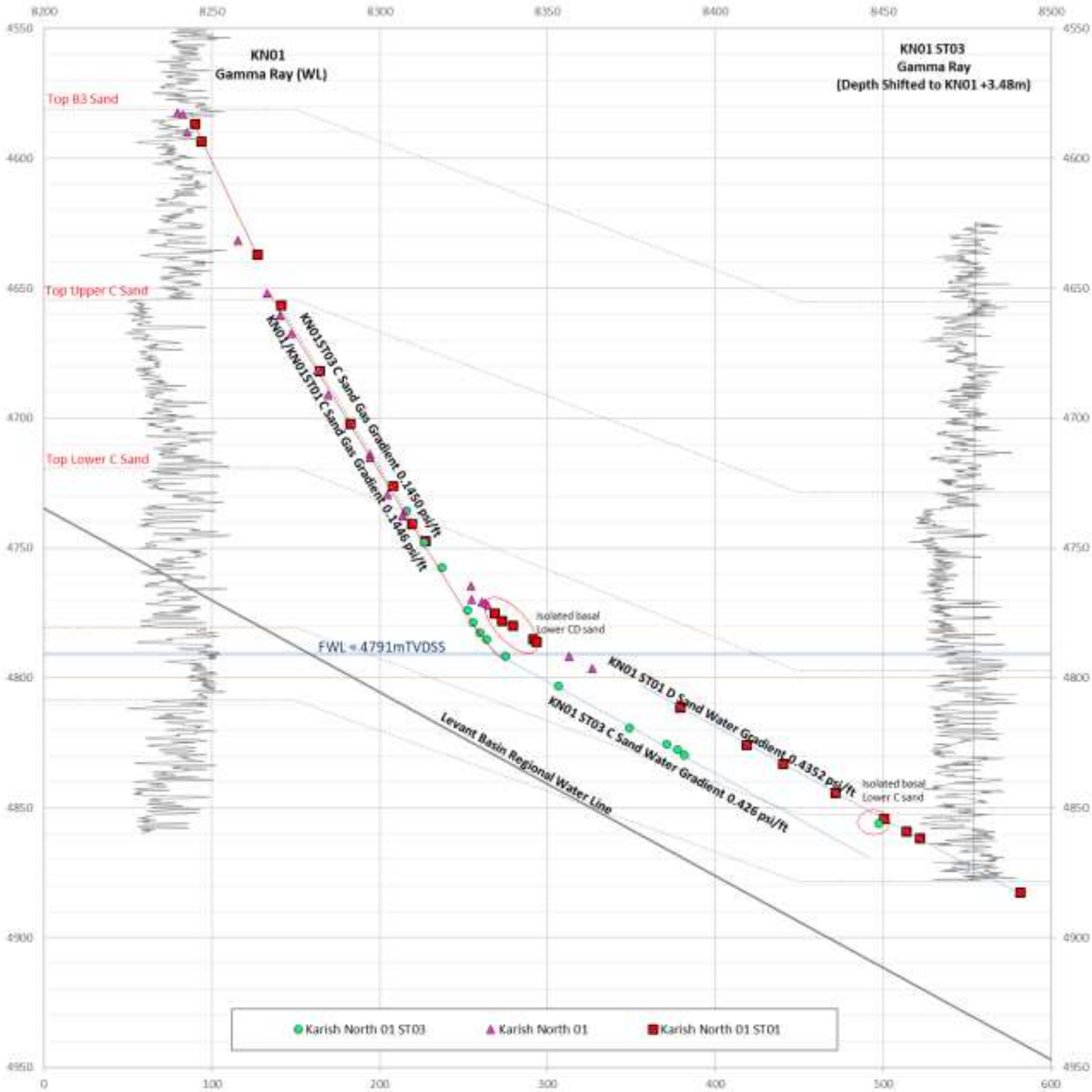


Figure 5-12 KN01/KN01 ST01 RDT Formation Pressures at recorded (WL) depth. KN01 ST03 corrected to WL depth and -4psi. GWC interpreted at 4791m TVDSS (C Sands)– KN01/KN01 ST01 RDT Formation Pressures at recorded (WL) depth. KN01 ST03 corrected to WL depth and -4psi. GWC interpreted at 4791m TVDSS (C Sands)

5.2.2.2.4 GWC Uncertainty Conclusion & Probabilistic Modelling Approach

The KN01 ST03 FWL interpretation is robust with a pipe to wireline depth shift being justifiable. The correction of the formation pressures to RDT data is small (4psi) and is reasonable. The pressure correction does not change the interpretation of the FWL/GWC.

The TVD depth error in the Karish North dataset is small. The most significant depth errors are

1) pipe to wireline correction (between 4.0 and 6.4m) giving a depth error of 2.4m for wireline depth.

2) Residual Survey error, quantified at 2.2m (1 std)

Compounding these errors (2.2m+2.4m) which should be considered a very conservative approach, gives **a** GWC range of 4786.4m (P100) to 4795.6m (P1), with a most likely (P50) GWC at 4791m, which has been captured in the Petrel workflow manager as a normal distribution where 1 std is 1.6m

5.2.2.3 Net Porosity

Two parameters have been set for the uncertainty in porosity: 1) the uncertainty in the calculation of porosity and 2) the uncertainty in the average net total porosity away from well control.

Given the significant gas effect on the neutron porosity log, particularly over clean gas bearing sandstones, both the methodology and the net pay cut-offs are uncertain. Energean carried out a sensitivity analysis on the uncertainty in the calculation of porosity which showed the uncertainty to be +/- 5%(P90-P10) and a Pmin-Pmax of +/-10%. on average for all reservoir units, which was applied in the probabilistic workflow. Whilst it could be argued that statistics are available for each individual reservoir unit, and there a porosity uncertainty per unit could be applied, the model has 29 zones, of which 28 zones contain net reservoir. Varying a single parameter (uncertainty in the calculation of porosity) multiple times results in a convergence around the mode, with the mode assumption being zero. Detailing a parameter multiple times therefore fails to capture the true range of uncertainty within the reservoir. The uncertainty range was applied as a uniform distribution given all methods of calculating average porosity in the sensitivity analysis are valid.

Capturing the uncertainty in the average net total porosity away from well control i.e. how representative the reservoir is away from the point of well control was modelled as a separate parameter, which is independent of the accuracy in the petrophysical calculation of net total porosity. The range of uncertainty modelled was +/-0.5 p.u. with a uniform distribution. The range of uncertainty was determined using geostatistical bootstrapping of all Karish Main and Karish North wells to test the dependency of the average porosity on the sample interval. The determined range is small, highlighting the continuity and predictable of net reservoir properties across the Karish Lease owing to the depositional environment. Furthermore, it is important to note that the modelling attempts to capture the range of *average* net porosity values in determining the pore volume uncertainty and *not* the absolute range of porosity.

5.2.2.4 Net-to-Gross

The NTG of the Upper C sand is 90%, and therefore only a small lowering of the NTG was considered (normal distribution 1std = 0.03) to capture 1) predictability of the net total porosity in all Karish Lease penetrations of the Upper C Sand reservoir and 2) the limited additional net reservoir upside in an very high NTG reservoir

The NTG of the Lower C sand and D Sand which have more thinly bedded reservoir have been modelled as a normal distribution with 1std = 0.08, with increases and decreases being allowed. The min/max uncertainty of the Lower C sand and D Sand was therefore +/-25% in order to capture the uncertainty associated with resolving thinly bedded reservoirs.

For NTG of the B Sand where a wider range is modelled. The B sands in Karish North and Karish Main are thinly bedded making the calculation of net pay problematic owing to the limited resolution of induction resistivity logs, and the inherent bias to mode constructive (shale prone intervals). The microresistivity log interpretation carried out by Task Fronterra for the Karish North 01 well, produced a low-mid-high estimate of NTG and associated net sand flag logs. For the Monte Carlo simulation, these have been modelled using the Swanson's mean approach (30:40:30), sampling the low case flag 30% of the time, the mid case 40% of the time and the high case 30% of the time.

5.2.2.5 Water Saturation

The water saturation methodology has not been varied in the Monte Carlo simulation. This is due to the acknowledged limitations of the employed SHF function in the reference case model, and the acceptance that this will be updated using the SCAL porous plate data, when available. Dependency (inverse relationship) between porosity and Sw therefore results in a natural variation in the water saturation by the Monte Carlo simulation of net total porosity. Whilst using a consistent SHF method and calculation, natural variation in the modelled Sw occurs by variation in net porosity and modelled GWC depth.

5.2.2.6 Probabilistic GIIP

The resulting GIIP range of for each of the Karish North structures (**Figure 5-13**) are presented per stratigraphic unit in **Figure 5-14**–**Figure 5-19**.

The GIIP range for the whole Karish North field is given in Figure **Figure 5-20** and presented as a Cumulative Distribution Function in **Figure 5-21**.
The tornado plot showing the GIIP sensitivity to each static parameter is given in

Figure 5-22.

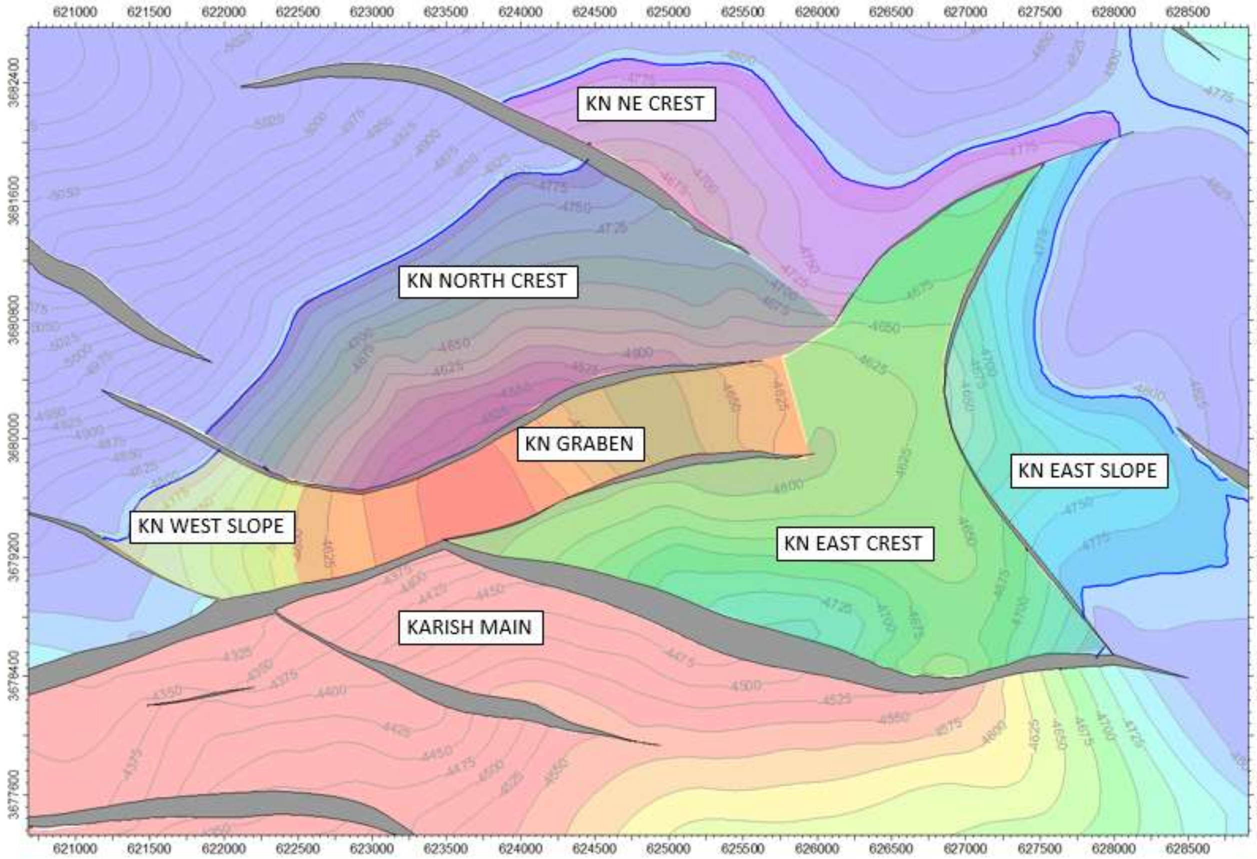
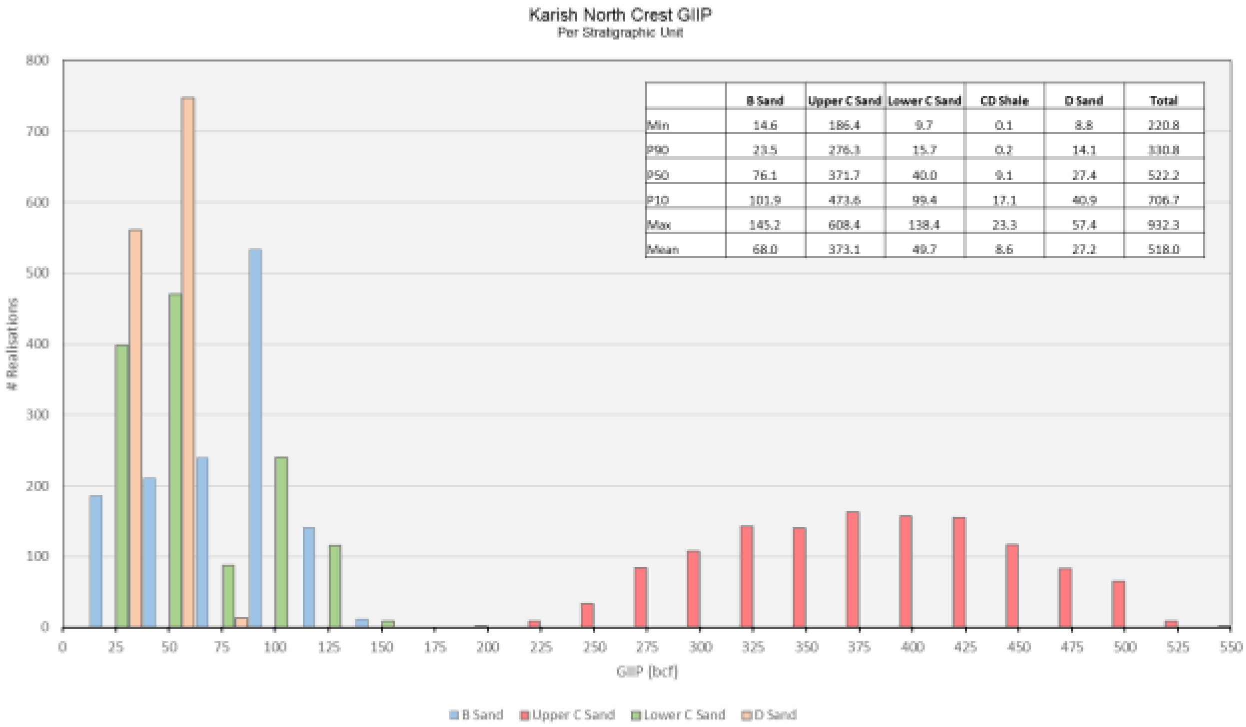
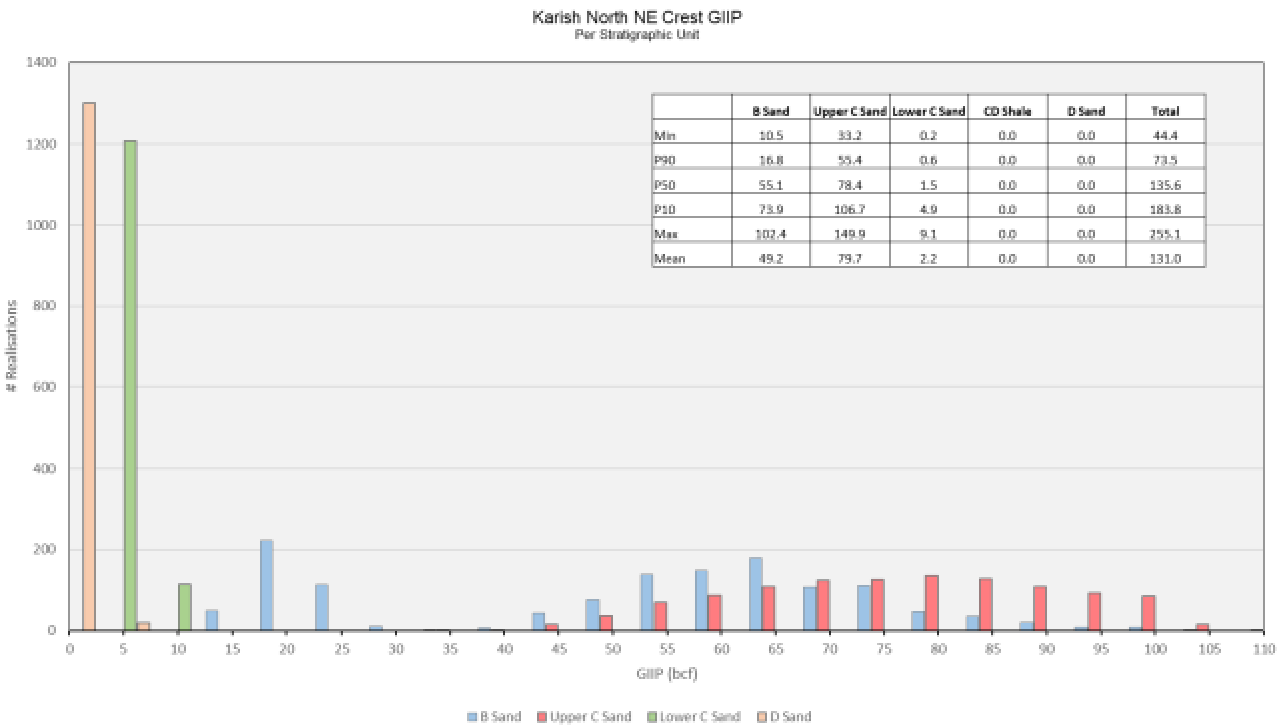


Figure 5-13 – Karish North Structural Components



	B Sand	Upper C Sand	Lower C Sand	CD Shale	D Sand	Total
Min	14.6	186.4	9.7	0.1	8.8	220.8
P90	23.5	276.3	15.7	0.2	14.1	330.8
P50	76.1	371.7	40.0	9.1	27.4	522.2
P10	101.9	473.6	99.4	17.1	40.9	706.7
Max	145.2	608.4	138.4	23.3	57.4	932.3
Mean	68.0	373.1	49.7	8.6	27.2	518.0

Figure 5-14 – Karish North Crest In Place Volume Range



	B Sand	Upper C Sand	Lower C Sand	CD Shale	D Sand	Total
Min	10.5	33.2	0.2	0.0	0.0	44.4
P90	16.8	55.4	0.6	0.0	0.0	73.5
P50	55.1	78.4	1.5	0.0	0.0	135.6
P10	73.9	106.7	4.9	0.0	0.0	183.8
Max	102.4	149.9	9.1	0.0	0.0	255.1
Mean	49.2	79.7	2.2	0.0	0.0	131.0

Figure 5-15 – Karish North NE Crest In Place Volume Range

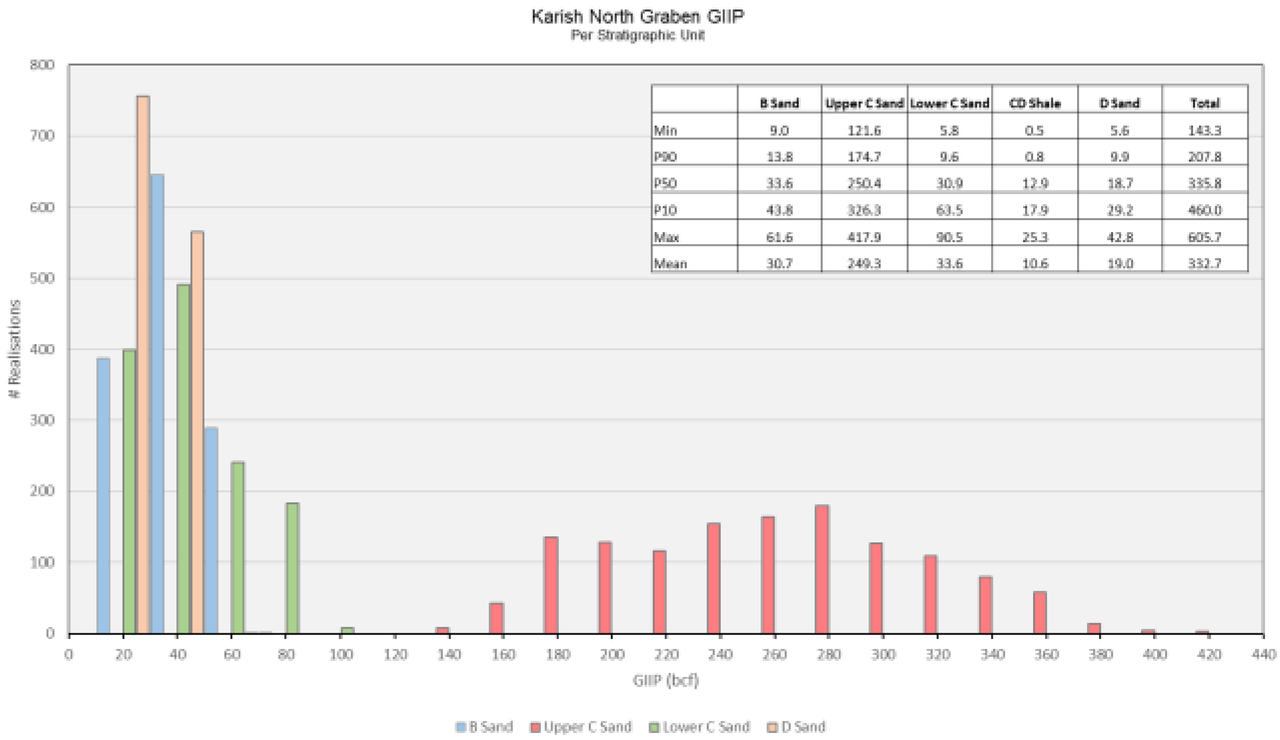


Figure 5-16 – Karish North Graben In Place Volume Range

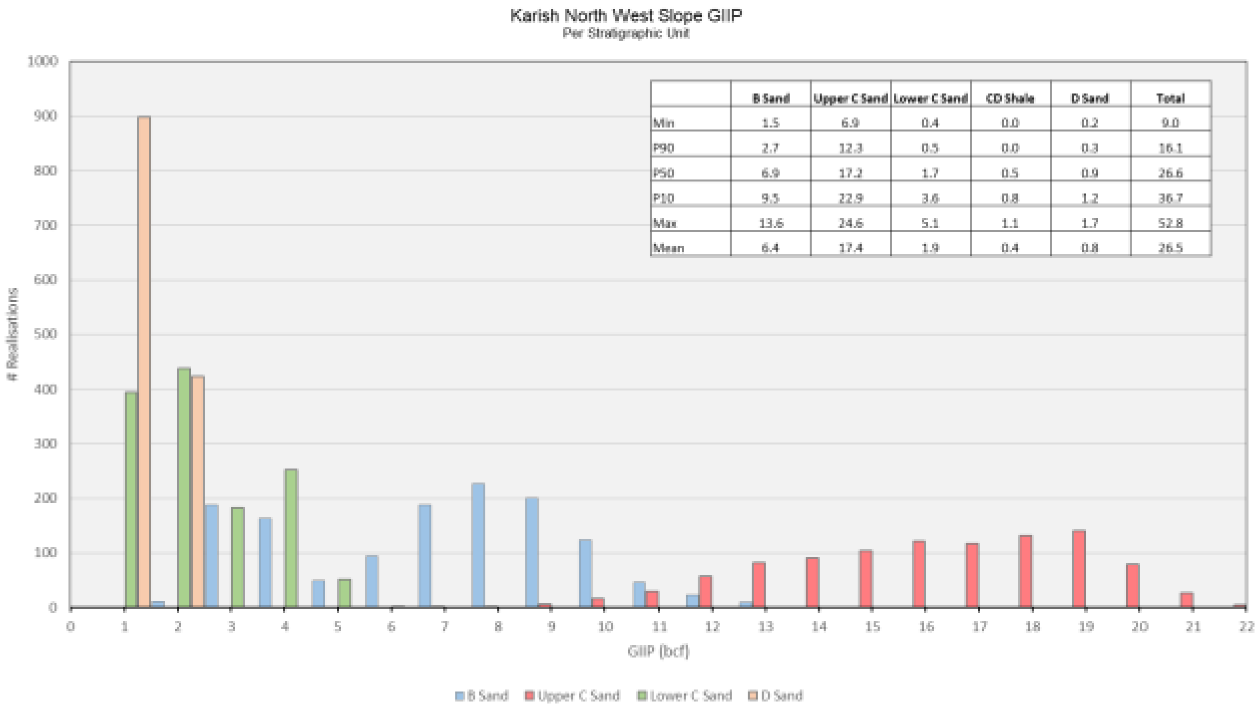


Figure 5-17 – Karish North West Slope In Place Volume Range

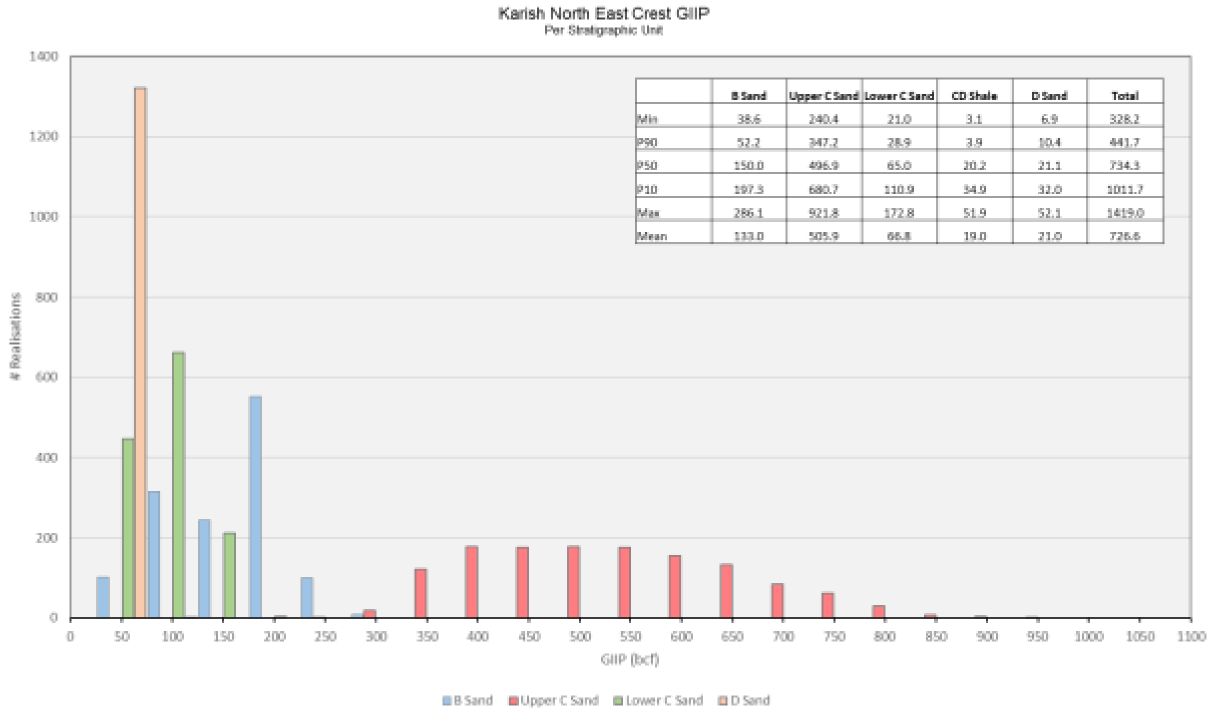


Figure 5-18 – Karish North East Crest In Place Volume Range

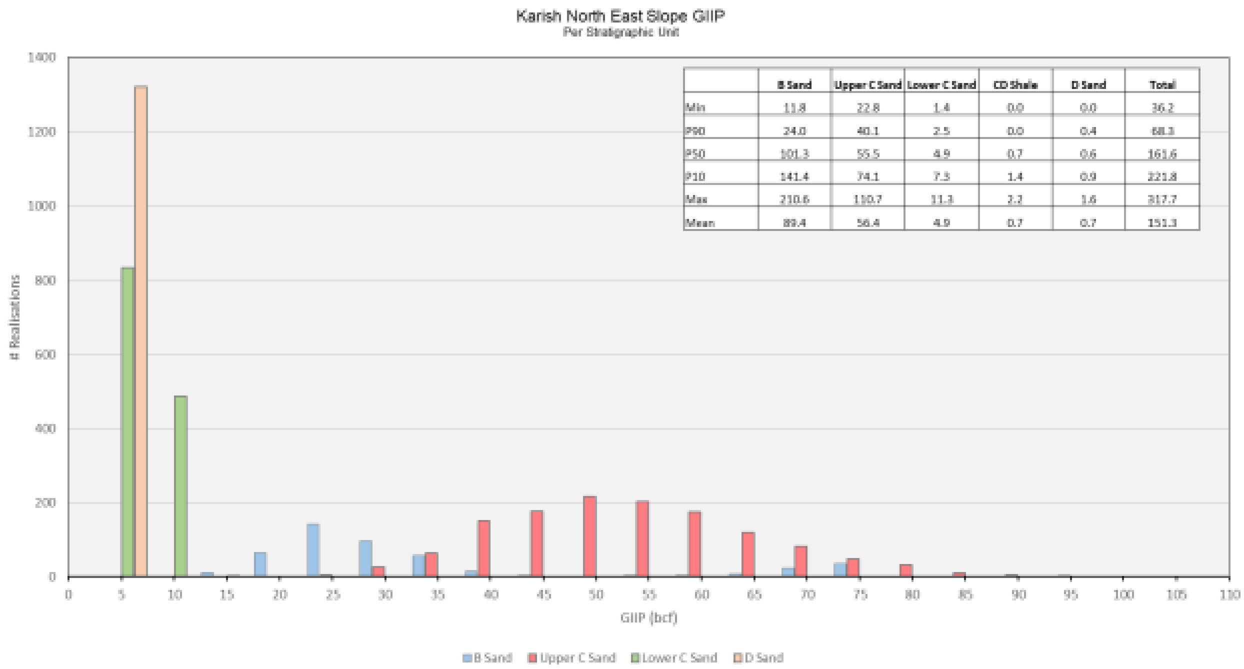


Figure 5-19 – Karish North East Slope In Place Volume Range

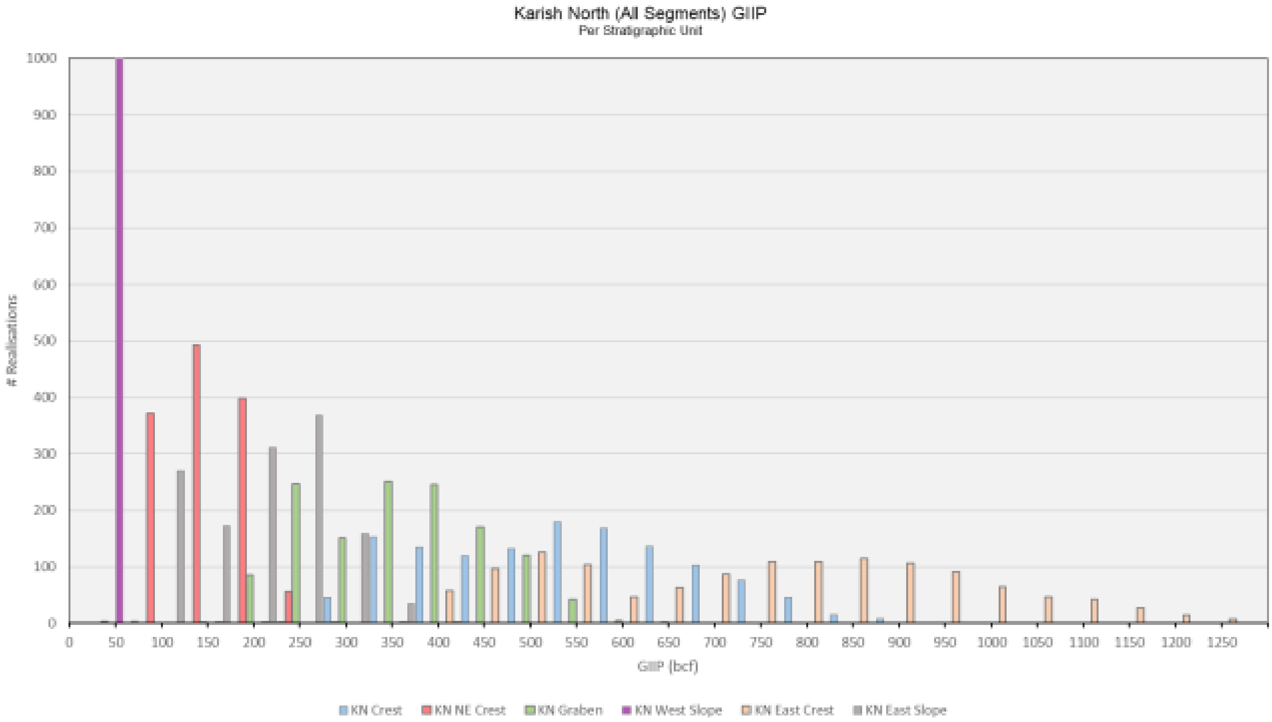


Figure 5-20 – Karish North Total (All Structures) In Place Volume Range

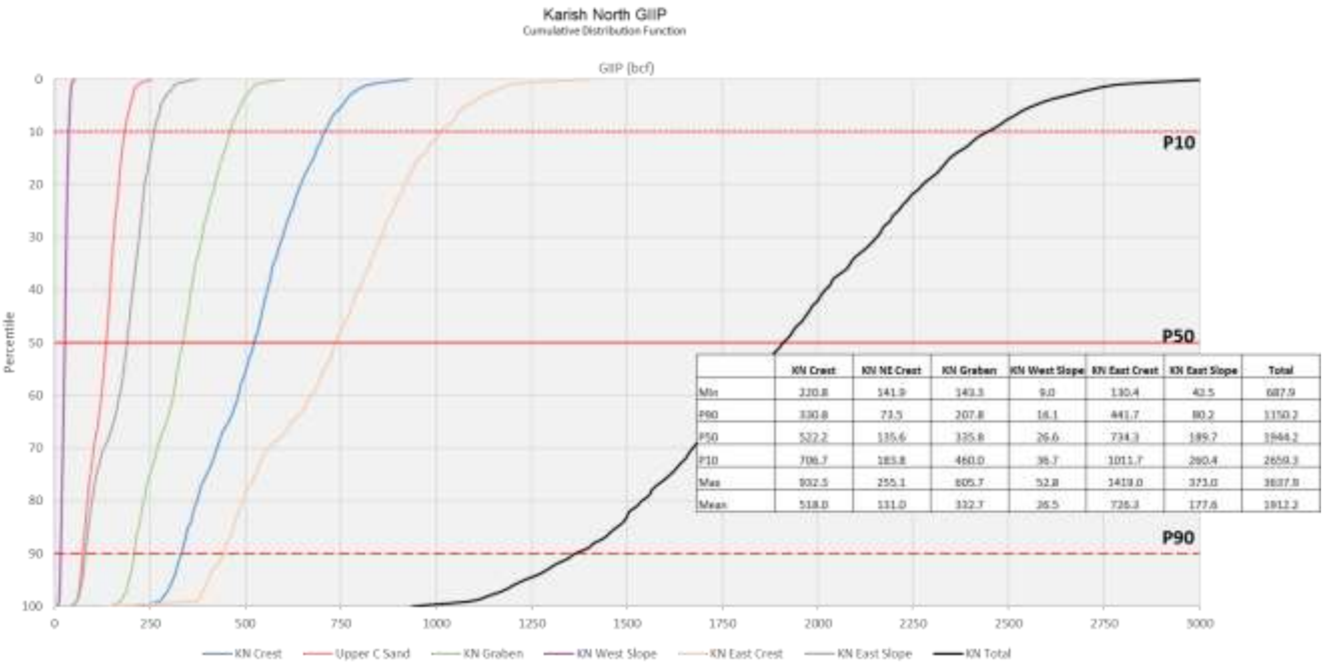


Figure 5-21 – Karish North In Place Volume Range CDFs

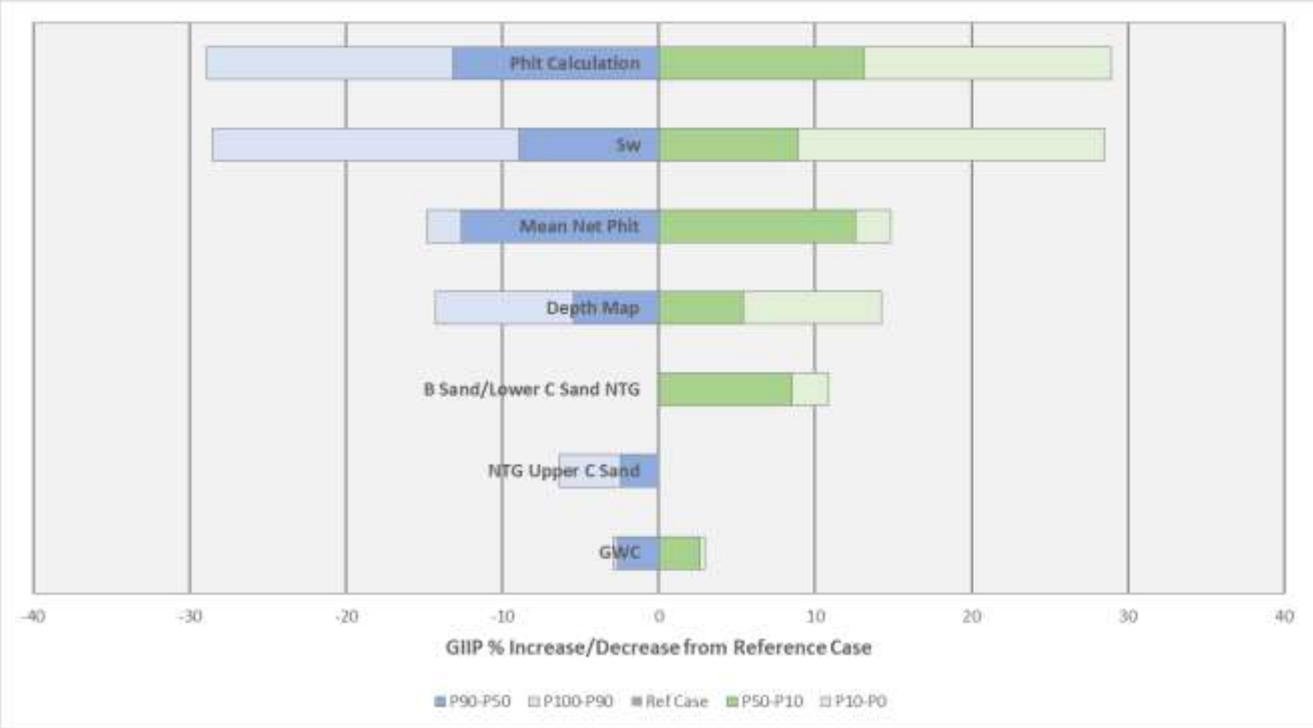


Figure 5-22 – Karish North In Place Volume Tornado Plot

5.3 Volumetrics Comparison with Competent Persons Report (DeGolyer and MacNaughton)

The Operator engaged DeGolyer and MacNaughton, Inc. (D&M) in early 2020 to complete a Competent Person's Report (CPR) for the purpose of estimating the Karish North unrisked Contingent Resources as of 31st March 2020.

5.3.1 Comparison of Methodology

D&M's approach to generating 1C-2C-3C Contingent Resource numbers differs from the approach taken by Energean to modelled volumetric uncertainty. D&M carry base case reservoir properties and assign uncertainty to the existence of accumulations in different substructures of the Karish North field i.e. D&M employ different areal polygons to describe the 1C-2C-3C outcomes as shown in (**Figure 5-23** to **Figure 5-25**). Energean use a Monte Carlo approach for the whole structure do not consider Karish North to have any isolated compartments.

Energean's interpretation of Karish North is broadly aligned with D&M, particularly with respect to the Karish North 01 well having proven the extension of the accumulation to the Karish North East Crest in the 2C case and the identification of significant volumes associated with the B sands.

5.3.2 Comparison of GIIP

A comparison of the D&M Low-Best-High (1C-2C-3C) Contingent Resource GIIP with the Energean P10-P50-P90 GIIP is given in (**Table 5-8**). The volumes compare well, with Energean carrying a similar range of volumetric outcomes, in all cases approximately 200bcf higher than the auditor. The volumes are very close when it is considered that Energean carry a D sand GIIP of 290bcf in the D sands, where D&M rightly do not consider this discovered. The D sand volume will be quantified at a later date as Prospective Resources

		1C	2C	3C
D&M	GIIP (bcf)	968	1735	2577
	GIIP (bcm)	27.4	49.1	73.0
		P90	P50	P10
Energean	GIIP (bcf)	1150	1944	2659
	GIIP (bcm)	32.6	55.1	75.3

Table 5-8: Comparison of D&M 1C-2C-3C GIIP with the Energean P90-P50-P10

The comparison with the reference case geological model (P65) is less favourable (**Table 5-9** to **Table 5-11**), which is predominantly for two reasons 1) differences in GRV, with Energean considering the full areal extent of the Karish North structure, whereas NSAI consider only 68% of the whole structure in the 2C case and 2) D&M do not carry any volumes for the D Sand for any volumetric outcome.

A comparison of the petrophysical properties calculated by D&M and Energean highlight the good agreement in GIIP per unit GRV (Section 5.3.3), and demonstrate that the difference between the Energean Reference Case model (P65) and D&M's 2C GIIP is driven by the change in GRV i.e. assumed areal extent of the accumulation.

D&M 2C GIIP						
	GRV (MMm^3)	Net Volume (MMm^3)	Pore Volume (MMm^3)	HCPV (MMm^3)	GIIP (MMm3)	
					Bcm	bscf
B Sands	1376	339.93	66.3	38.7	15.61	551.0
C Sands	837	512.07	110.0	79.0	33.14	1170.1
CD Shale & D Sands	27	7.683	1.6	1.0	0.39	13.7
Total	2240	860	178	119	49.13	1734.8

Table 5-9: DM 2C GIIP by stratigraphic unit

Energean Reference Case Model						
	GRV (MMm^3)	Net Volume (MMm^3)	Pore Volume (MMm^3)	HCPV (MMm^3)	GIIP (MMm3)	
					Bcm	bscf
B Sands	2204	341	58	32	11.90	421.0
C Sands	1270	839	173	117	43.50	1535.0
CD Shale & D Sands	329	105	21	10	3.80	135.0
Total	3803	1285	252	159	59.20	2091.0

Table 5-10: Energean Reference Case GIIP by stratigraphic unit

Difference (DM - Energean)						
	GRV (MMm^3)	Net Volume (MMm^3)	Pore Volume (MMm^3)	HCPV (MMm^3)	GIIP (MMm3)	
					Bcm	bscf
B Sands	-828	-1	9	7	3.71	130
C Sands	-433	-327	-63	-38	-10.36	-365
CD Shale & D Sands	-302	-97	-20	-9	-3.41	-121
Total	-1563	-425	-74	-41	-10.07	-356

Table 5-11: Difference – D&M 2C GIIP with Energean Reference Case GIIP

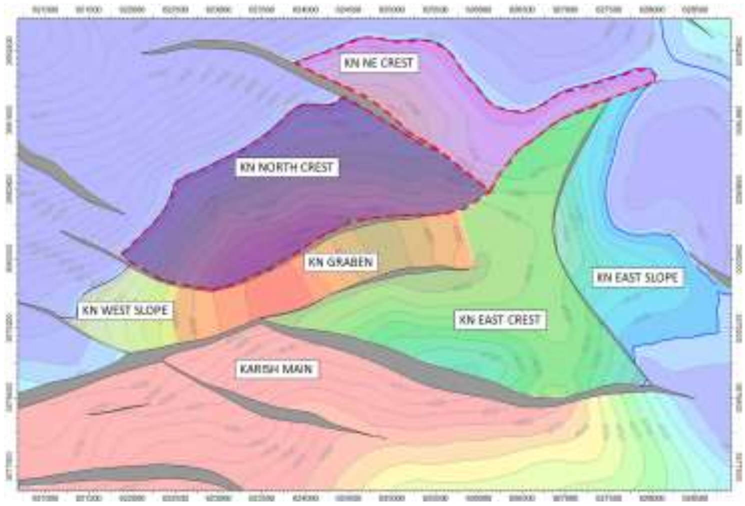


Figure 5-23 – D&M 1C Volume Polygon (red stippled polygon). The 1C volume includes KN North Crest and NE Crest only

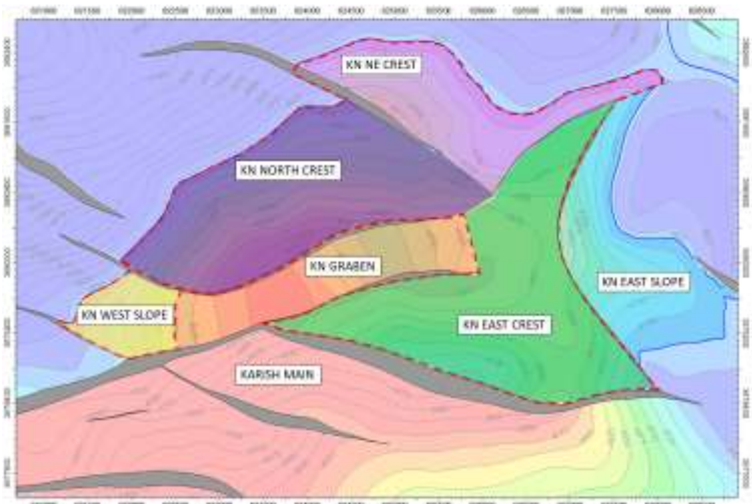


Figure 5-24 – D&M 2C Volume Polygon (red stippled polygon). The 2C volume includes KN East and KN West Slope in addition to the areas included in the 1C polygon

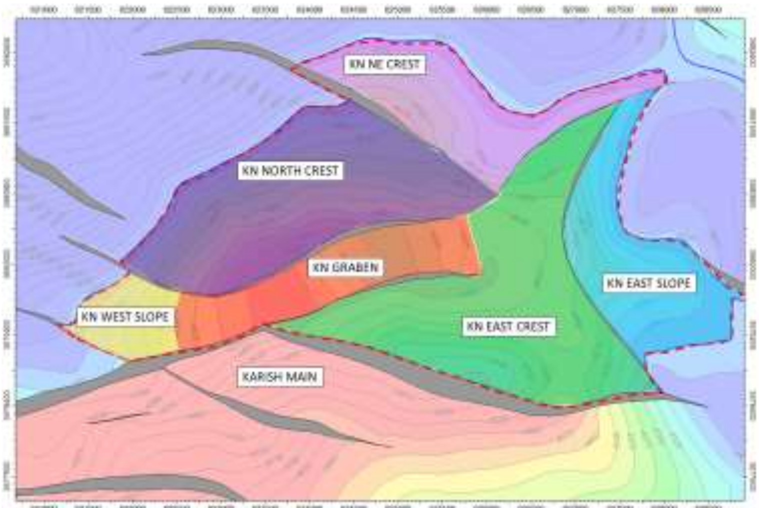


Figure 5-25 – D&M 3C Volume Polygon (red stippled polygon). The 3C volume includes KN East Slope and KN Graben in addition to the areas included in the 2C polygon

5.3.3 Comparison of Petrophysical Parameters

A comparison of D&Ms petrophysical averages and those of the Energean reference case geological model are presented in **Table 5-12** and **Table 5-13**

D&M Petrophysical Parameters				
	NTG	Net Phi	Sw	Bg
	frac	frac	frac	scm/rcm
B Sands	0.38	0.21	0.33	413.59
C Sands	0.61	0.22	0.28	419.25
CD Shale & D Sands	0.29	0.21	0.37	374.36

Table 5-12: D&M Petrophysical Averages per Stratigraphic Unit

Energean Reference Case Petrophysical Parameters				
	NTG	Net Phi	Sw	Bg
	frac	frac	frac	scm/rcm
B Sands	0.15	0.17	0.44	372.00
C Sands	0.66	0.21	0.33	372.00
CD Shale & D Sands	0.32	0.20	0.52	372.00

Table 5-13: Energean Reference Case Geological Model Petrophysical Averages per Stratigraphic Unit

The major difference between Energean's analysis and that of D&M is the NTG of the B Sands. D&M are in good agreement with Energean that the B sand net sand thickness is significantly greater than that which would be calculated from conventional petrophysical analsysis of triple combo data. D&M have undertaken independent thin bed analysis of the processed XRMI data, showing Energean's analysis to be conservative, with the auditor calculating a net sand thickness in good agreement with Energean's high case net sand flag. Furthermore, D&M calculate more favourable net sand properties (Sgas and Phit) relative to the Operator.

The C sand parameters are very comparable, with Energean being more optimistic on NTG, whilst D&M calculate lower Sw. This reflects a difference in the net pay cut-offs applied.

Given the petrophysical properties between D&M and Energean are similar, with D&M generally being slightly more optimistic, applying the D&M 1C/2C/3C volumetric polygons to the Energean Reference Case Geological model provides a useful comparison of the Energean and D&M volumetrics.

5.3.4 Application of Auditor Areal Polygons to Energean Reference Case Geological Model

A comparison of volumes when applying D&M's areal volumetric polygons to Energean's geological mdoel is given in **Table 5-14**. The comparison shows that, in all cases, for the same GRV, D&M consistently calculate a larger GIIP. This indicates that Energean's approach to defining Karish North volumes is conservative with respect to petrophysical properties.

	1C	2C	3C
D&M	968	1735	2577
Energean	731	1530	2091

Table 5-14: Application of the D&M 1C/2C/3C Volumetic Polygons to Energean Reference Case Geological for comparison to D&M Volumetric Range

6 Reservoir Engineering

This section details the information incorporated in the dynamic reservoir simulation model and outlines the physical properties of the containment system, as they relate to fluid flow performance, i.e. rock compressibility, permeability, shales etc. and the reservoir temperature/pressure limits of the system and how they impact on the fluid PVT properties. It then describes how the model is constructed and the effect of different reservoir development scenarios on field performance.

6.1 Compressibility

To estimate the effect of a gradual increase in hydrostatic stress over the 400 – 4000 psi net confining stress range, six plugs were identified to cover the range of core porosity measurements seen in the KN01 routine core analysis (RCA) measurements. Summarising the measurements, pore volume reduction over the 400 – 4000 psi varied from 3.96 to 7.55%, averaging 6.13%. Uniaxial compression for the samples decreased by an average of 15 psi^{-1} ($x10^{-6}$) over the pressure range. Pore volume reduction fitted well with quadratic regression analysis and uniaxial compression, maintaining linearity across the pressure range.

Further pore volume compressibility measurements are planned on the Upper C Sand and Lower C Sand from wells KM-02 and KM-01 respectively, which are analogues for Karish North properties. As with Karish North sample selection, these will be selected based on the range of core porosity data seen in the wells.

6.2 Reservoir Pressure

Estimates of reservoir pressure and temperature are based on data acquired by the RDT tool detailed in sections 3.2 which was run in KN01 & KN01-ST01 and the Geotap LWD which was run in KN01-ST03.

One of the major drivers for drilling KN01-ST02 & KN01-ST03 is that the gas water contact was not identified on a pressure versus depth plot of the RDT pressure points in either KN01 or KN01-ST01, see **Figure 6-1**. It can be seen that the intersection between the C sand gas gradient and the D sand water gradient results in a Free Water Level (FWL) of 4767 m TVDSS above locations in the C sand where single phase gas samples were acquired in KN01-ST01, resulting in a Gas Down To (GDT) of 4779 m TVDSS. In such a high quality reservoir it seemed unlikely that there existed a transition zone of >10m, so it was hypothesized that the D sands were over-pressured compared to the C sands in Karish North. Once the Geotap pressures were acquired showing the pressure of the water leg in the Karish North C sands it was seen that the D sands were indeed over-pressured compared to the C sands (see **Figure 6-2**).

A small discrepancy between the gas gradient in KN01-ST03 and that acquired using the RDT tool in KN01/KN01-ST01 is noted. It is not thought to be caused by barriers within the C sands, but more by comparing pressure acquired by an LWD Geotap tool with the wireline run RDT tool. From **Figure 6-2** it can be seen that the GWC has been defined as 4791 m TVDSS based on the intersection of the C sand gas and water gradients from the KN01-ST03 well.

In terms of reservoir datum pressure, the C Sand pressure extrapolated to 4512 m TVDSS (the Karish Main GWC) based on the observed gas gradient of 0.146 psi/ft is estimated at 8201.4 psia, or 566.6 barg. The KN01-ST03 formation pressures show that the C Sand water leg is recorded with an ~45psi over pressure relative to the Karish Main aquifer.

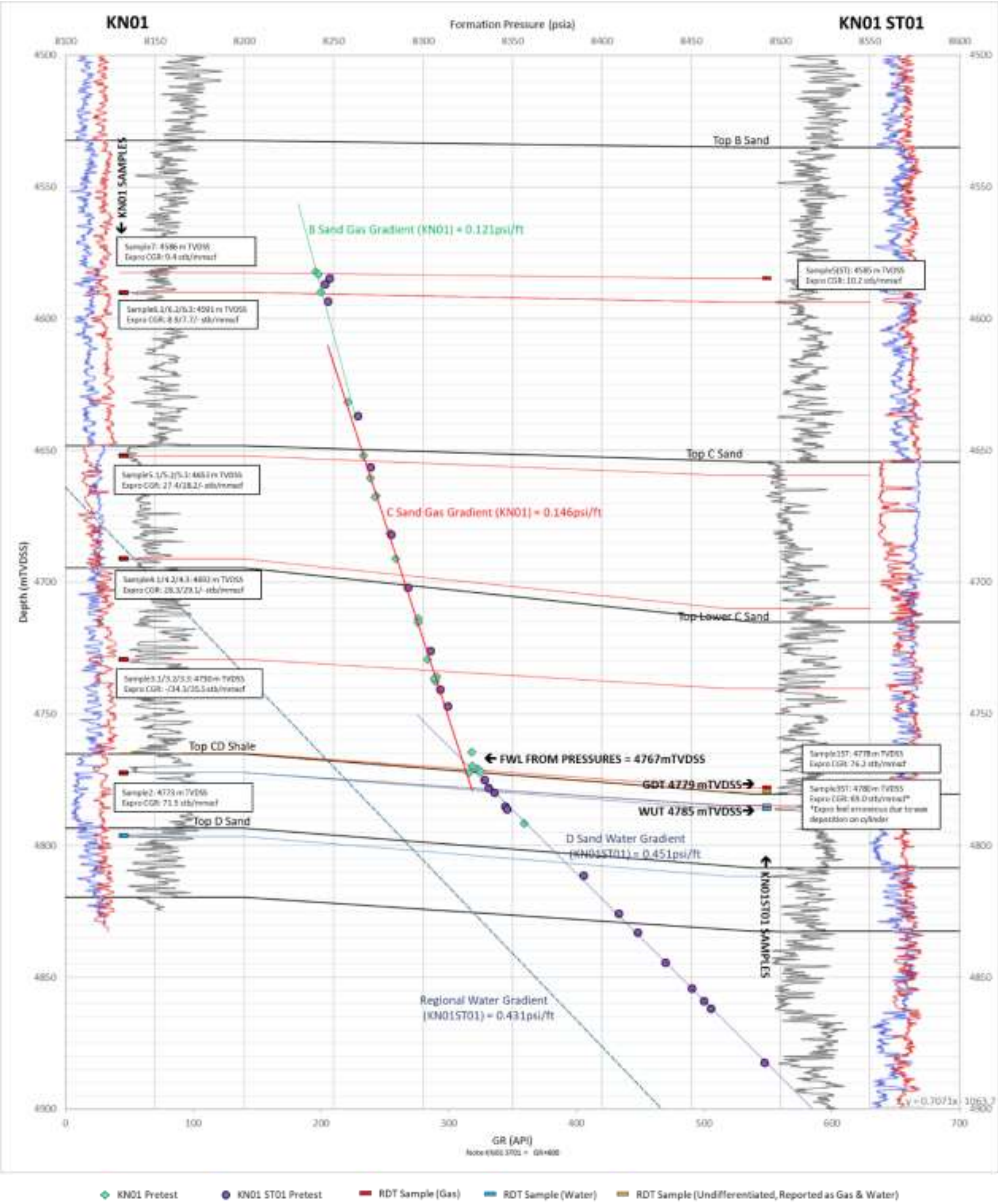


Figure 6-1 – Pressure versus Depth for KN01 & KN01-ST01 Showing Sample Locations & Properties

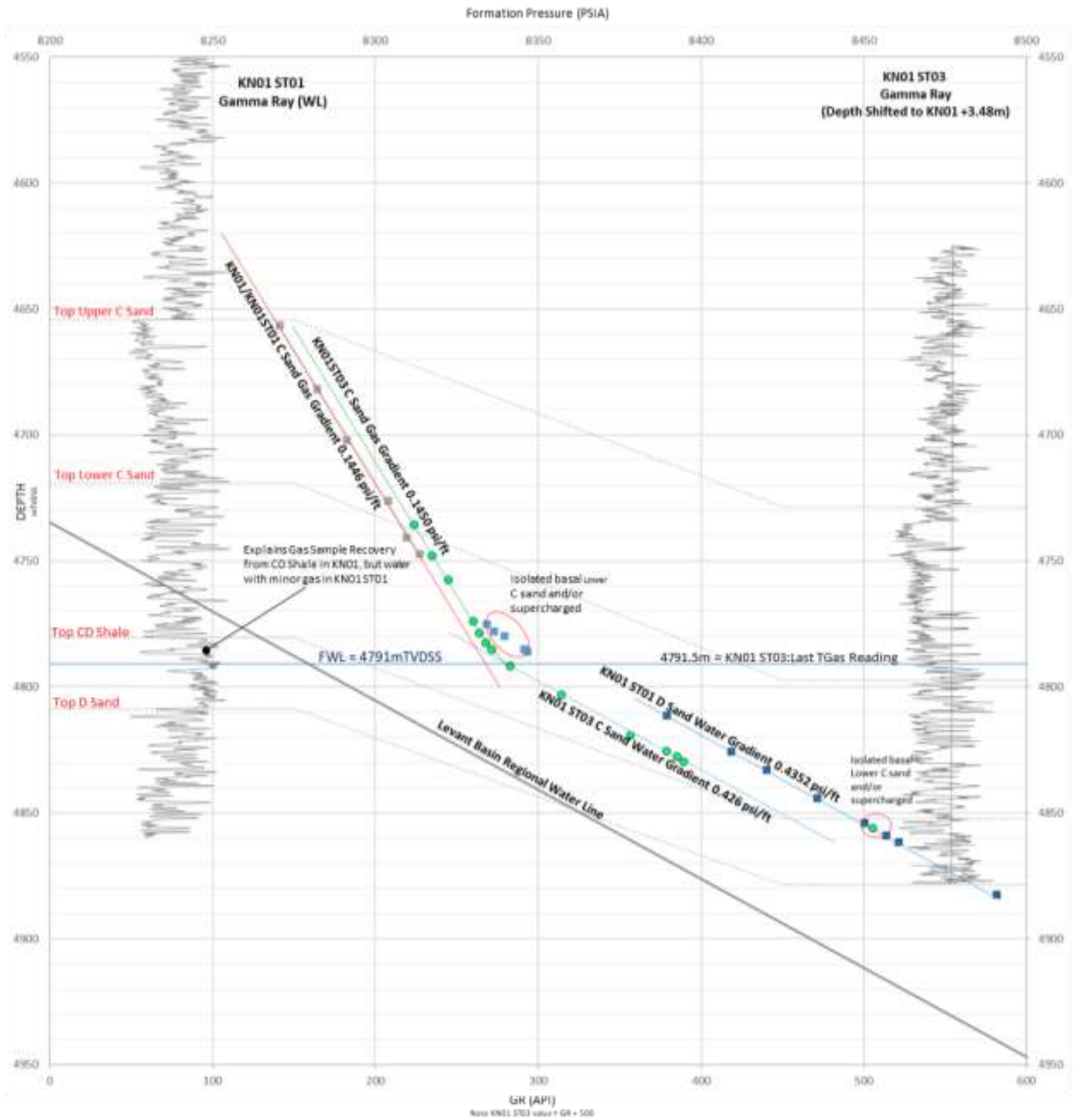


Figure 6-2 – Pressure versus Depth for KN01-ST03 and KN01-ST01

6.3 Reservoir Temperature

The pre-drill prognosed reservoir temperature for Karish North was estimated at 78.8 degC at a depth of 4774m TVDSS (the interpreted GWC based on the location of the seismic “flat spot”). During the RDT runs on KN01 and KN01-ST01 the Pre-Test temperatures were significantly below those anticipated pre-drill. It is thought this is due to wellbore cooling, with the near wellbore sands targeted by these tests being exposed to the cooler drilling fluids, in the case of KN01 for several days. Therefore, the hottest of the RDT points, which is from a water sample in KN01 and supported by water samples in KN01-ST01 has been selected to define the Karish North Reservoir temperature. This point read a fluid temperature entering the RDT tool of 78.4 degC at 4796.3 m TVDSS. The temperature gradient applied is that defined by the Karish-1 temperature points and is

0.0322 degC/m. **Figure 6-3** below details the available data for Karish North compared to the Karish-1 data. Larger data points indicate fluid temperatures obtained at the end of physical fluid sampling stations, which are anticipated to provide more accurate reservoir temperature readings than those obtained from the pre-test for the pressure points.

The temperature of Karish North defined at the datum depth of 4512 m TVDSS (the GWC for Karish Main) is therefore estimated at 69.2 degC using a temperature gradient of 3.2 degC per 100m change in vertical relief.

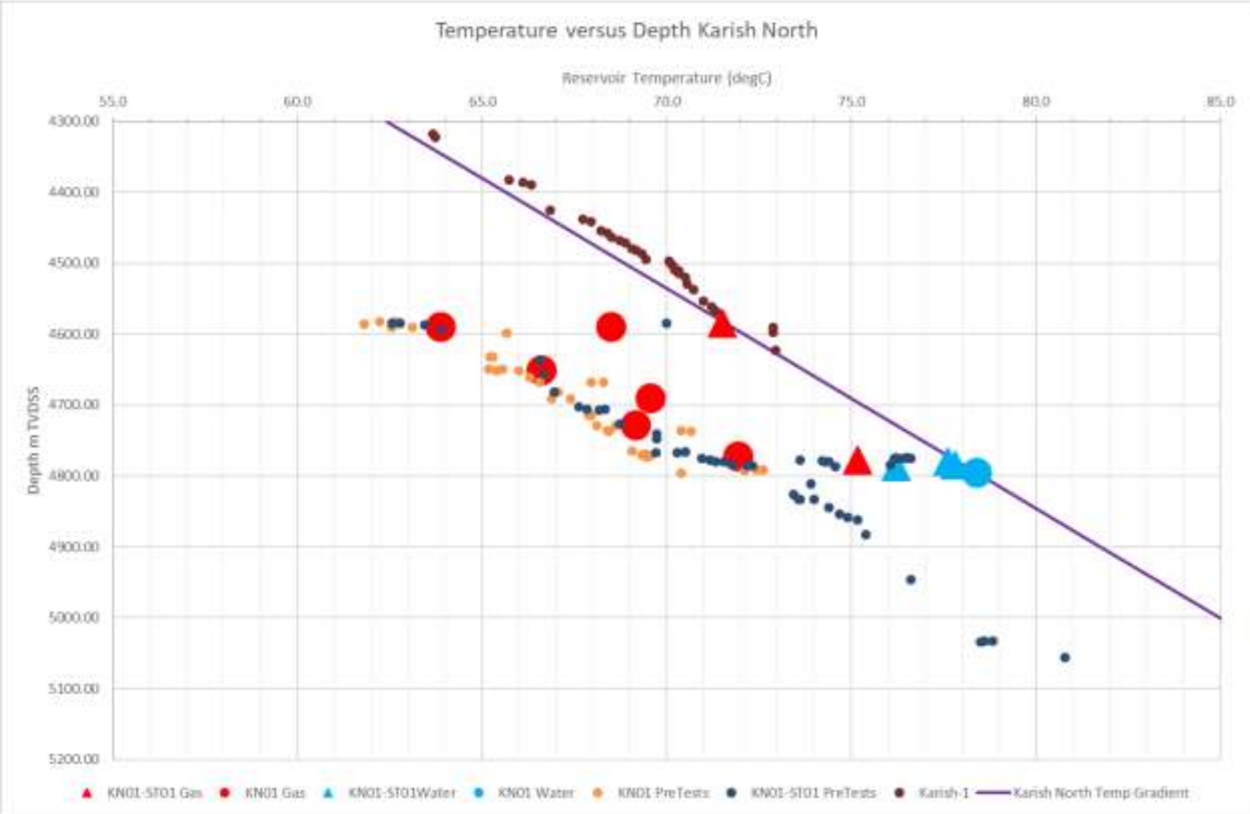


Figure 6-3 – Karish North Temperature Data compared with Karish-1

6.4 Aquifer Description

The aquifer is the prolific Tamar Sandstones seen across the Levantine Basin. Based on the initial formation pressures in Myra, Aphrodite, Tanin and Karish a strong, regionally connected aquifer is assumed. Early production data from the Tamar field also supports a strong aquifer model. The base case assumption is that the Karish North aquifer size is >100 times larger than the Karish North accumulation.

The Karish North 01 ST03 formation pressures show a C Sand water leg that is approximately 45 psi overpressured relative to the Karish Main aquifer. One explanation for this could be compartmentilisation of the Karish North aquifer. This is considered to be a very low probability due to the complete lack of a fault network that can isolate Karish North from the wider Levant Basin. The relative Karish North aquifer is more likely to be due to a dynamic system, which has not yet reached equilibrium.

The full extent of the aquifer is difficult to quantify, owing to the proximity to the edge of the Israeli Economic Development Zone and therefore lack of access to seismic data beyond the northern extent of the Karish Lease. Mapping the Tamar sands to the northern extent of the available seismic data shows the aquifer pore volume to be a minimum of 7x larger than the Karish North hydrocarbon interval pore volume. At the northernmost extent of the seismic data, the Tamar C sands still have a thickness of approximately 160m TST. As a low case scenario, the aquifer pore volume cannot reasonably be expected to be any less than 20x the Karish North accumulation pore volume.

The modelled aquifer size has therefore been modelled as a low of 20x the Karish North pore volume and a most likely of 100x.

6.5 PVT Modelling

Downhole fluid samples were acquired in both KN01 and KN01-ST01. A full analysis of these samples has been performed at Expro Reading.

Figure 6-1 shows the location of the samples and their flash Condensate Gas Ratios (CGRs) based on the gas composition defined from cryogenic distillation of the gas. This clearly shows a variation in fluid properties with depth. Once the KM02 samples were also acquired and analysed it was seen that Karish Main also exhibits a variation of fluid properties with depth, although its gas is leaner than that observed in Karish North.

At each depth where hydrocarbon samples were acquired in KN01, a full suite of analysis has been performed, including constant composition expansion, constant volume depletion, separator flash and wax properties. Further wax analysis is ongoing with KAT laboratories. **Table 6-1** defines which analyses were performed on each sample.

Sample Number	Cylinder Number	Sample Depth m MD		Sampling Pressure psia	Temperature °C	Sample Description ethod Number	Sample Transfer from Bottomho	Gas Thermal Restoration	Sample Validation - Bottomho	Cryogenic Distillation	Separator Test	Constant Composition Expansion	Constant Volume Depletion	Water Flash	Wax Content	Water Analysis	Gas Chromatography of Gases	Gas Chromatography of	Wax Appearance Temperat	Wax Disappearance (Dissoluti
							Analysis Requirement													
1	3119-M1-F	4841.98	D Sand	8363	70.4	Bottomhole Wate	✓							✓		✓	✓			
2	2404-M1-F	4818.01	C-D Shale	8326	70.4	Bottomhole Gas	✓	✓	✓	✓	✓	✓	✓				✓	✓		
3.1	1952-M1-F	4775.00	Middle of Lower C Sand	8298	69.3	Bottomhole Gas	✓	✓												
3.2	6111-M1-F	4775.00	Middle of Lower C Sand	8298	69.3	Bottomhole Gas	✓	✓	✓	✓		✓			✓		✓	✓	✓	✓
3.3	0577-M1-F	4775.00	Middle of Lower C Sand	8298	69.3	Bottomhole Gas	✓	✓	✓	✓	✓	✓	✓		✓		✓	✓	✓	✓
4.1	6119-M1-F	4736.71	Bottom of Upper C Sand	8281	67.9	Bottomhole Gas	✓	✓	✓	✓							✓	✓		
4.2	4192-M1-F	4736.71	Bottom of Upper C Sand	8281	67.9	Bottomhole Gas	✓	✓	✓	✓	✓	✓	✓		✓		✓	✓	✓	✓
4.3	1999-M1-F	4736.71	Bottom of Upper C Sand	8281	67.9	Bottomhole Gas	✓	✓							✓				✓	✓
5.1	1187-M1-F	4697.59	Top of Upper C Sand	8264	65.0	Bottomhole Gas	✓	✓	✓	✓	✓	✓	✓		✓		✓	✓	✓	✓
5.2	1968-M1-F	4697.59	Top of Upper C Sand	8264	65.0	Bottomhole Gas	✓	✓	✓	✓					✓		✓	✓	✓	✓
5.3	4182-M1-F	4697.59	Top of Upper C Sand	8264	65.0	Bottomhole Gas	✓	✓												
6.1	5694-M1-F	4635.70	B Sand	8242	62.1	Bottomhole Gas	✓	✓	✓	✓	✓	✓					✓	✓		
6.2	5623-M1-F	4635.70	B Sand	8242	62.1	Bottomhole Gas	✓	✓	✓	✓							✓	✓		
6.3	1914-M1-F	4635.70	B Sand	8242	62.1	Bottomhole Gas	✓	✓												
7	1918-M1-F	4630.90	B Sand	8040	61.8	Bottomhole Gas	✓	✓	✓	✓							✓	✓		
1 (ST)	4439-M1-F	4850.49	Bottom of Lower C Sand	8338	73.6	Bottomhole Gas	✓	✓	✓	✓					✓		✓	✓	✓	✓
2 (ST)	5081-M1-F	4859.70	C-D Shale	8348	74.9	Bottomhole Wate	✓							✓		✓	✓			
3 (ST)	1724-M1-F	4852.11	Bottom of Lower C Sand	8349	75.6	Bottomhole Gas/	✓	✓	✓	✓				✓		✓	✓	✓		
4 (ST)	6102-M1-F	4858.23	C-D Shale	8346	75.7	Bottomhole Wate	✓							✓		✓	✓			
5 (ST)	1916-M1-F	4635.99	B Sand	8242	69	Bottomhole Gas	✓	✓	✓	✓					✓		✓	✓	✓	✓

Table 6-1 – PVT Analysis Performed on Karish North Fluids by Expro

Once the fluid properties were known it was possible to define a Fluid Modelling strategy for the field and characterise the fluids for use in the subsurface, well, surface network and process simulation models. Given that the fluid properties vary with depth it was decided that the reservoir model would assign PVT regions representing the individual sampling locations, this would allow Energean to understand the effect of the richer fluids on the overall gas properties, and in particular the CGR and liquid yield that could be obtained from Karish North during production. It also allows Energean to assess various completion strategies to understand if higher quantities of heavier fluids can be obtained by completing the wells with longer OHGPs (Open Hole Gravel Packs) than were used in Karish Main.

Therefore, the reservoir simulation model output not only details rates, pressures and temperatures, but it also details the expected composition of the gas produced for the well for each time step and provides a composition that will vary over time as a result of mixing of reservoir fluids and liquid drop-out within the reservoir and near wellbore region. In order to aid transfer of reservoir model outputs to the flow assurance and process modelling work, it was decided that the fluid characterisation utilised for the reservoir simulation model should be the same as the characterisation used in the well, network and process models. It was therefore decided that the Fluid Characterisation would cover both Karish North and Karish Main Fluid properties and allow for the interaction of Karish North and Main fluids in the surface networks and processing to be modelled and the impact of processing capacities and pressure drops to be calculated.

Assured Flow Solutions, a consultancy specialised in flow assurance prepared a number of different characterisations using several Equation of State (EoS) models that honoured the data to a greater or lesser extent. The final fluid characterisation that has been utilised for modelling purposes used the "Peng-Robinson 78" Equation of State with tuned Penelux Volume shift and characterises the fluid using 5 pseudo components and 22 standard components.

Initially, the EoS was tuned based on analysis from all reservoir zones in both KM02 & KN01. However, in matching Sample 2 from KN01, which was acquired in the C-D shale and has the highest CGR of all the samples, we reduced the accuracy of the match to the KM02 and Upper C sand samples in KN01. It was therefore decided to exclude KN01 Sample 2 from the tuning process as it was felt more important to honour the Upper C Sand samples from KN01 as this zone contains >75% of the overall gas in place in Karish North.

In order to provide an input PVT region covering the base of the Lower C sand and C-D Shale in Karish North for simulation purposes a composition has been derived using the final Fluid Characterisation that matches the properties of this sample. The properties of the five new pseudo components are defined in red in **Table 6-2 – Karish Main and Karish North Fluid Characterisation using Peng-Robinson 78 EoS with Penelux Volume ShiftTable 6-2** below. All Binary Interaction Parameters for Hydrocarbon Components are set to zero. With this characterisation most sample properties are matched to within 5% and all within 10% of the observed experimental value calculated by Expro.

Karish Main & Karish North Fluids Common Pseudos (Without CD-Shale) - Component Properties [PR78] (with Tuned Volume Shift)																
Component	Molecular Weight	Specific Gravity	Ideal Liquid Density (kg/m3)	Carbon No.	Tc (°K)	Pc (bars)	w	Vc (m^3/kmol)	Tb (°C)	T of Melt (°C)	H of fusion (J/mol)	Parachor ((dyne/cm) ¼cm³/mol)	S of fusion (J/mol/K)	Cp of fusion (J/mol/K)	VS PR 1 (m3/mol)	VS PR 2 (m3/mol /K)
NITROGEN	28.01	0.28			126.19	33.97	0.04	0.089414	-195.80	-209.85	360.00	60.10		8.94	-3.65E-06	
CO2	44.01	0.84			304.13	73.79	0.22	0.094119	-53.15	-56.57	8652.30	72.20		13.80	-1.01E-06	
METHANE	16.04	0.15			190.56	46.00	0.01	0.098628	-161.52	-182.48	9284.00	72.60		9.76	-3.37E-06	
ETHANE	30.07	0.37			305.33	48.73	0.10	0.145560	-88.60	-183.30	2860.00	110.00		19.15	-3.58E-06	
PROPANE	44.10	0.52			369.85	42.49	0.15	0.200000	-42.10	-181.70	3526.00	150.80		31.89	-7.22E-06	1.05E-08
ISOBUTANE	58.12	0.56			407.85	36.41	0.18	0.259067	-11.73	-159.42	4610.00	191.70		17.86	-9.63E-06	1.11E-08
N-BUTANE	58.12	0.58			425.16	37.97	0.20	0.255102	-0.50	-138.30	4664.00	190.30		25.11	-9.19E-06	1.38E-08
ISOPENTANE	72.15	0.62			460.45	33.78	0.23	0.306000	27.88	-159.90	5147.00	229.40		32.19	-1.07E-05	1.74E-08
NEOPENTANE	72.15	0.60			433.75	31.95	0.20	0.303000	9.48	-16.39	3096.00	229.00		-6.67	-1.30E-05	1.77E-08
N-PENTANE	72.15	0.63			469.70	33.67	0.25	0.310986	36.06	-129.68	8401.00	231.00		39.52	-9.73E-06	2.16E-08
I-HEXANE	86.18	0.66			497.50	30.11	0.28	0.366400	60.26	-153.60	6268.00	269.46		53.46	2.45E-06	-1.88E-08
HEXANE	86.18	0.66			507.82	30.19	0.30	0.369566	68.73	-95.32	13080.00	271.00		43.54	-4.21E-06	1.13E-08
METHYLCYCLOPENTANE	84.16	0.75			532.79	37.86	0.23	0.319000	71.81	-142.42	6929.00	243.97		37.92	1.23E-06	-1.93E-08
BENZENE	78.11	0.89			562.16	48.99	0.21	0.259000	80.09	5.45	9920.00	206.00		1.34	-2.79E-06	3.50E-09
CYCLOHEXANE	84.16	0.78			553.56	40.71	0.21	0.308000	80.73	6.45	2677.00	240.70		14.63	-5.80E-06	3.74E-09
METHYLCYCLOHEXANE	98.19	0.77			572.19	34.72	0.23	0.368000	100.93	-126.57	6751.00	281.81		47.54	4.54E-06	-2.84E-08
TOLUENE	92.14	0.87			591.79	41.05	0.26	0.316000	110.63	-95.00	6636.00	246.00		45.03	3.94E-07	8.10E-10
ETHYLCYCLOHEXANE	112.22	0.79			609.15	30.41	0.25	0.430000	131.80	-111.31	8334.10	320.07		43.07	1.24E-05	-2.34E-08
ETHYLBENZENE	106.17	0.87			617.20	36.07	0.30	0.374000	136.20	-94.95	9184.00	283.86		48.21	1.12E-05	-2.79E-08
M-XYLENE	106.17	0.87			617.05	35.36	0.32	0.376000	139.12	-47.95	11565.00	284.00		39.88	5.23E-06	-2.46E-09
P-XYLENE	106.17	0.86			616.20	35.12	0.32	0.379000	138.37	13.25	16804.00	284.00		19.82	5.49E-06	-2.10E-09
O-XYLENE	106.17	0.88			630.30	37.31	0.31	0.369000	144.43	-25.20	13609.00	283.00		24.43	3.45E-06	-3.88E-09
C7-8	100.68	0.74	0.89	7.48	539.67	32.32	0.33	0.399505	105.79	-96.38	10618.50	252.06	60.07	93.25	-1.05E-05	-6.32E-09
C9-11	133.91	0.78	0.94	9.90	604.35	27.97	0.44	0.530664	164.75	-45.79	18164.70	336.88	79.89	110.89	-1.54E-05	-7.30E-09
C12-19	199.68	0.83	1.00	14.58	702.10	22.00	0.63	0.798859	260.39	5.56	33204.50	503.74	119.14	145.47	-2.46E-05	-3.59E-08
C20-29	321.39	0.88	1.06	23.34	828.50	16.60	0.92	1.316300	382.19	47.00	61390.30	812.23	191.76	208.31	-4.14E-05	-9.86E-08
C30+	477.70	0.92	1.11	34.49	942.06	13.43	1.17	2.011660	486.62	71.62	98265.60	1208.25	285.01	286.81	-6.00E-05	-1.73E-07

Table 6-2 – Karish Main and Karish North Fluid Characterisation using Peng-Robinson 78 EoS with Penelux Volume Shift

Fluid Composition - Common Pseudos KM&KN Fluids without CD-Shale							
	Karish Main Fluids				Karish North Fluids		
	D Sand	LC Sand	C Sand	Top C Sand	LC Sand	C Sand	B Sand
NITROGEN	0.678	0.608	0.597	0.595	0.834	0.861	0.72
CO2	0.096	0.094	0.093	0.08	0.15	0.298	0.066
METHANE	89.423	94.079	95.196	95.319	88.143	89.411	94.482
ETHANE	2.869	1.697	1.426	1.388	4.09	3.666	2.02
PROPANE	1.983	1.064	0.832	0.83	1.971	1.726	0.949
ISOBUTANE	0.611	0.312	0.242	0.235	0.53	0.47	0.241
N-BUTANE	0.678	0.334	0.252	0.245	0.593	0.525	0.245
ISOPENTANE	0.369	0.194	0.149	0.144	0.33	0.303	0.149
NEOPENTANE	0.006	0.003	0.002	0.002	0.005	0.004	0.002
N-PENTANE	0.24	0.121	0.091	0.087	0.214	0.193	0.082
I-HEXANE	0.224	0.118	0.088	0.083	0	0	0
HEXANE	0.114	0.058	0.043	0.04	0.321	0.274	0.116
METHYLCYCLOPENTANE	0.12	0.066	0.052	0.049	0	0	0
BENZENE	0.019	0.005	0.002	0.002	0.101	0.084	0.037
CYCLOHEXANE	0.108	0.052	0.038	0.036	0	0	0
METHYLCYCLOHEXANE	0.19	0.096	0.073	0.069	0	0	0
TOLUENE	0.027	0.007	0.003	0.002	0.134	0.098	0.038
ETHYLCYCLOHEXANE	0.033	0.017	0.013	0.013	0	0	0
ETHYLBENZENE	0.022	0.012	0.009	0.009	0.021	0.016	0.007
M-XYLENE	0.0265	0.01	0.006	0.0055	0.043	0.0305	0.0125
P-XYLENE	0.0265	0.01	0.006	0.0055	0.043	0.0305	0.0125
O-XYLENE	0.021	0.009	0.006	0.006	0.032	0.023	0.009
C7-8	0.65	0.321	0.248	0.238	1.013	0.828	0.356
C9-11	0.614	0.317	0.241	0.231	0.604	0.485	0.2
C12-19	0.669	0.315	0.233	0.229	0.606	0.499	0.193
C20-29	0.149	0.068	0.048	0.046	0.174	0.141	0.053
C30+	0.034	0.013	0.011	0.011	0.048	0.034	0.01
*All BIPs between H/Cs are 0							

Table 6-3 – Fluid Compositions for Karish Main and Karish North Reservoir Zones using Fluid Characterisation defined in Table 6-2

6.6 Mini-DST Results

The Halliburton Reservoir Description Tool (RDT) was used to perform four mini-DSTs in KN01 at the locations detailed in **Table 6-4**.

Test#	MD m	TVDSS m	Zone	Kh mD.ft	K mD
69.0	4635.7	4590.3	B Sand	552	130
72.0	4630.9	4585.5	B Sand	228	82
79.0	4713.4	4668.0	Upper C Sand	806	107
82.0	4782.3	4736.8	Lower C Sand	667	60

Table 6-4 – Mini-DST Locations in KN01

The Halliburton RDT tool uses its oval pad to pump out of the formation for several minutes before allowing the formation pressure to build-up. The pressure build-up may then be analysed using pressure transient analysis to calculate permeability thickness. This analysis is sensitive to the assumed bed thickness. As can be seen from **Table 6-4** and **Figure 3-3**, the permeabilities derived from the mini-DST are an order of magnitude lower than those derived from core. Recent information gained during the KM02 well clean-up operations suggests that permeabilities are more in line with those observed from the core, therefore core results have been utilised in populating the geological model.

6.7 Well Performance

Well models were constructed using the Petroleum Experts Prosper nodal analysis package for each of the retained completion options to enable an understanding of the impact of each design on well deliverability across the field life (see section 7.2.3.1.2).

Inflow performance parameters used were as follows in **Table 6-5**.

	B Sands	Upper C Sands	Lower C Sands	
Permeability[1]	275	900	77	mD
Porosity	18.1	23.7	18.3	%
NTG	0.092	0.899	0.252	
Initial Reservoir Pressure	567	569.5	571.3	Barg
Initial Reservoir Temperature	70.8	73.4	75.9	DegC
GOR (Gas Oil Ratio- wellbore)	112000	32309	28145	scf/stb
Formation Interval	115	45	70	m
Gravel Pack Thickness[2]	1.1875	2.475	2.475	in
Drainage Area	6250000			m^2
Sw Connate	22			%
Gravel Pack Permeability	350000			mD
Inflow Performance Model	Petroleum Experts 5 (suitable for wet gas)			

Table 6-5 – Prosper Modelling Inflow Performance Parameters

The PVT entered into the model was the Peng-Robinson Equation of State described in 6.5 above. The composition entered matched the Top of the Upper C Sand in KN01. In Prosper the Equation of State is converted into Black Oil properties for use in the Petroleum Experts 5 inflow relationship. Therefore, for well models incorporating inflow from zones other than the Upper C the GOR and reservoir conditions are also entered which allows Prosper to prepare Black Oil Properties for these alternative zones of interest, which are used in calculating inflow performance.

In terms of Vertical Flow Performance, the conceptual completions referred to in section 7.2.3.1.2 were reflected in the individual well models utilizing IDs and material roughnesses provided by Halliburton.

In order to reflect the likely FWHPs imposed on the wells GAP models were constructed of the three main facility concepts to define the range of likely FWHPs for arrival pressures at the FPSO between 210 and 250

[1] Permeability based on Arithmetic Average Permeability for zone reduced by 50% to account for overburden- likely permeability will be measured higher on well clean-up pressure transient analysis

[2] Gravel pack thickness is lower for B Sands as assume CHGP inserted within 9 5/8" Casing

Bara. Note: whilst it will be possible to reduce the arrival pressure further, it is not understood at which pressure is the lowest arrival pressure that the maximum throughput of the FPSO can be maintained, below which there will be an as yet undefined impact on FPSO throughput. As Karish North is anticipated to be in production during the peak demand from signed Gas Sales Agreements it is thought prudent to assume the lowest arrival pressure is 210 Bara.

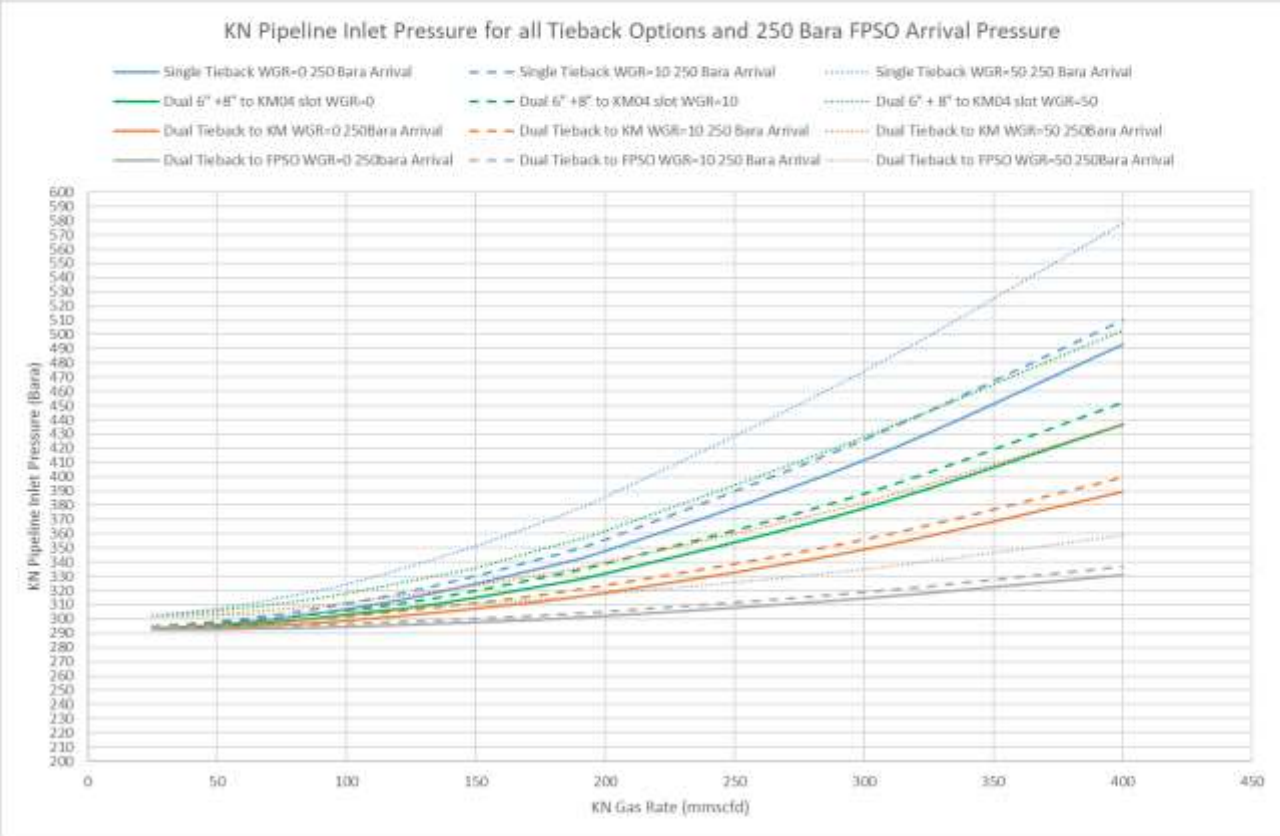


Figure 6-4 – Minimum FWHP for various facility development concepts and flowrates arriving at FPSO at 250 Bara

Using 347.8 barg, the Single Line Tieback FTHP for an FPSO arrival pressure of 250 bara at a Water Gas Ratio (WGR) of 0.1 bbls/mmscf and 200mmscfd and comparing across the range of Reservoir Pressures anticipated during production gives the results shown in **Table 6-6** which shows the impact of reducing the tubing size, which is also shown for different WGRs as reservoir pressure declines in **Figure 6-5** & **Figure 6-6**. Tubing size reduction reduces productivity of the wells.

Reservoir Pressure	KM Design: Upper C 7in Tubing	KM Design: Upper C 5.5in Tubing	KM Design: B Workover 7in Tubing	OHGP Upper/Lower C 7in Tubing	Smart Well B/Upper C 5.5in Tubing
Barg	**mmscfd**	**mmscfd**	**mmscfd**	**mmscfd**	**mmscfd**
569.5	315	228	256	307	101
500	210	148	184	199	71
450	109	74	108	101	41

Table 6-6 – Comparison of Production Performance for different completion concepts for Karish North

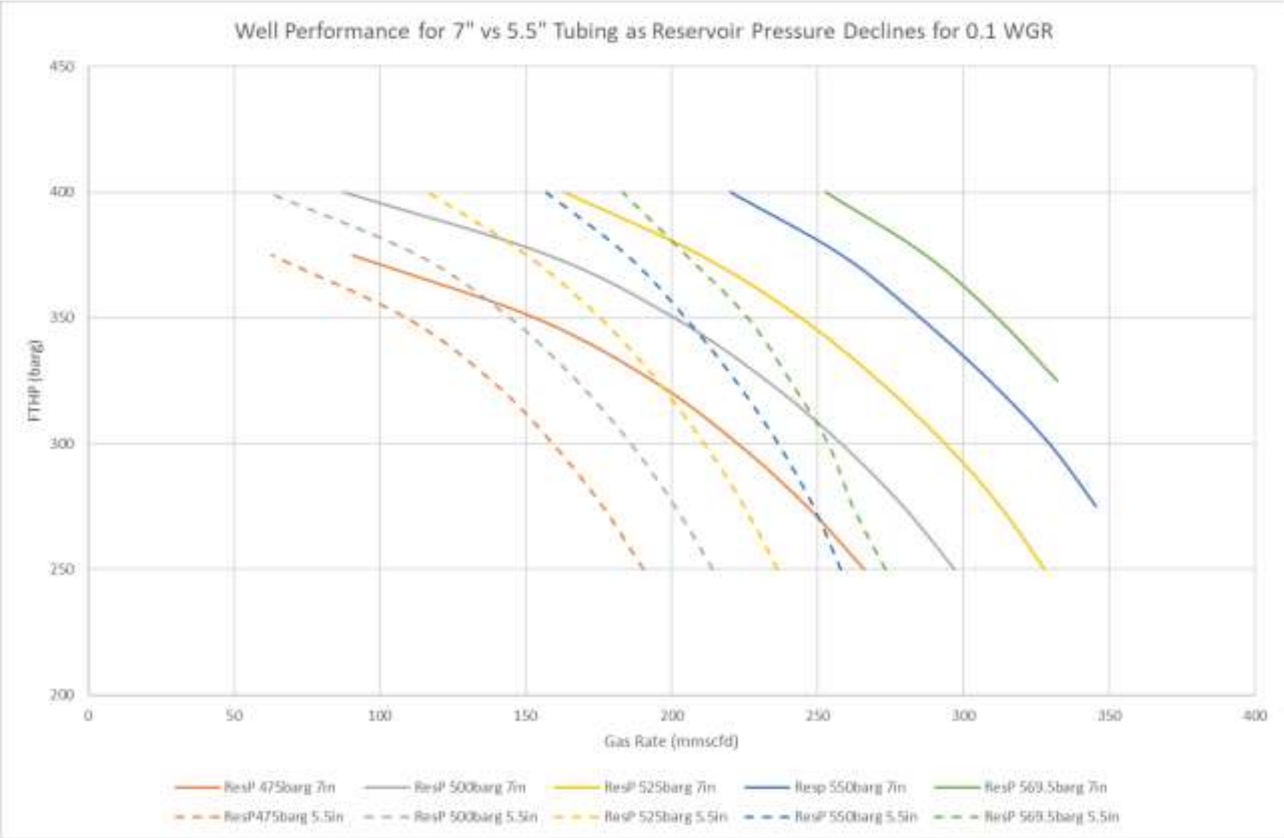


Figure 6-5 – Well Performance for 7" vs 5.5" Tubing as Reservoir Pressure declines for WGR=0.1 bbls/mmscf

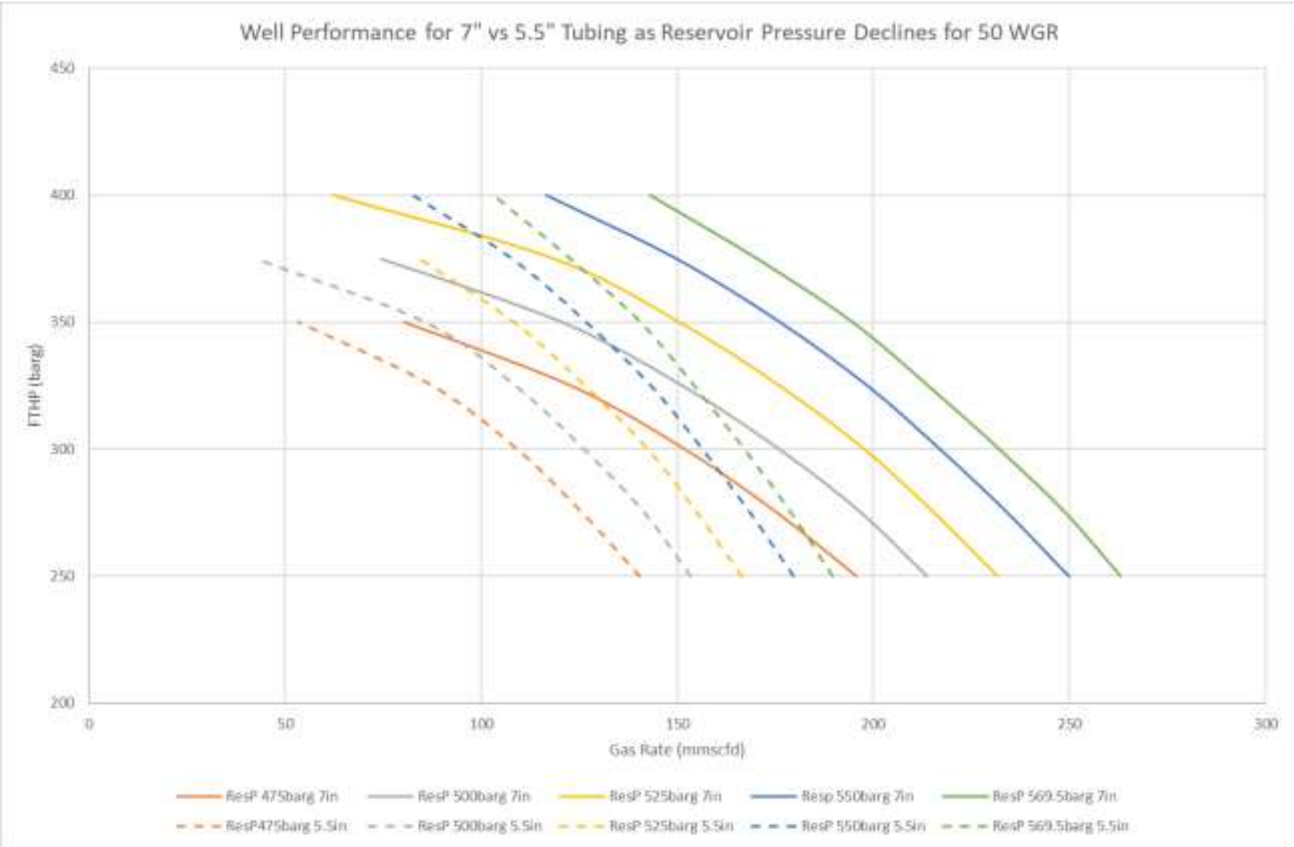


Figure 6-6 – Well Performance for 7" vs 5.5" Tubing as Reservoir Pressure declines for WGR=50 bbls/mmscf

Tubing size can also have an effect on the minimum stable flow of the well. In **Figure 6-7** the PE5 Stability criteria is plotted with both tubing sizes. If PE5 is 1 there is likely to be unstable flow, if it is zero then it is likely to be stable. In the case shown, at 50 bbls/mmscf WGR, the minimum rate at which the well flows stably is similar (~25mmscfd). Therefore, there appears to be no benefit in moving to a smaller tubing diameter. This will be further assessed by reviewing the performance of the recent KM02 welltest and tuning the model to actual conditions.

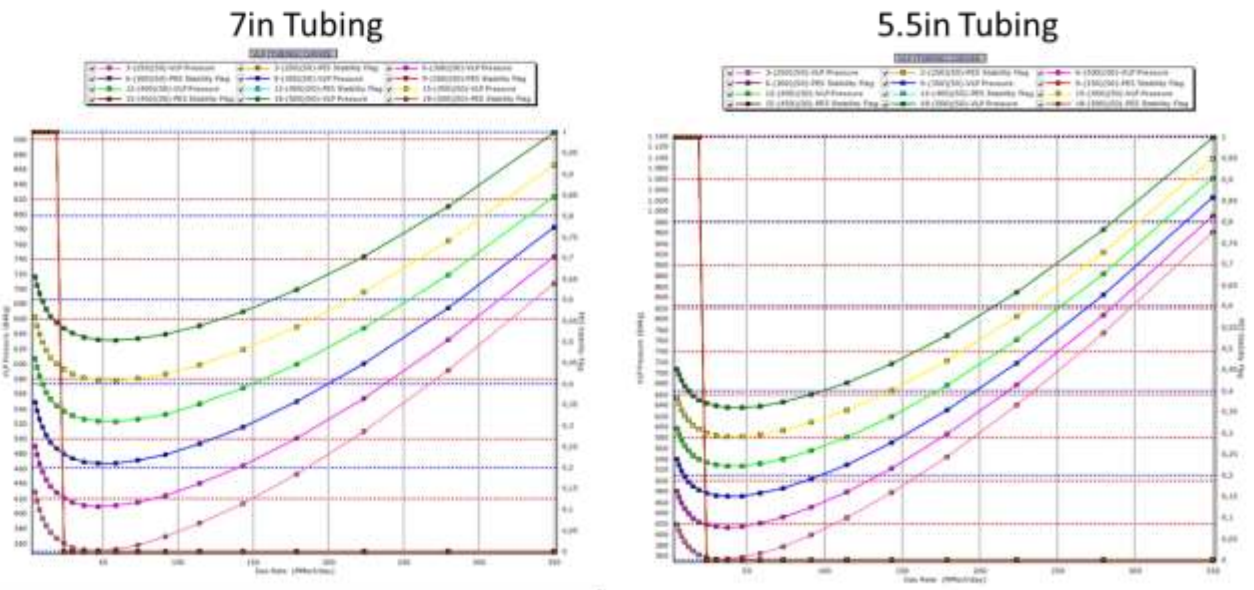


Figure 6-7 – Comparison of Vertical Lift Performance Curves for the Karish Main Completion design with 7" or 5.5" Tubing (WGR=50 bbls/mmscf)

Table 6-5 above also compares the SMART completion well performance against the other retained cases. If the SMART well is compared against the 5.5" Tubing KM Base Case design it can be seen that there is further loss in productivity in the Lower Completion (as both Upper Completions are similar). In general production is approximately half of that of the simpler single zone OHGP design. The reason for this is the reduced flow area available to both the C Sands and the B Sands versus options which develop each zone separately. Section 7.2.3.1.2.3 describes the flow areas and compares those achieved in the SMART well against those achieved in wells with 5.5" or 7" tubing. In considering these it is also important to reflect that the Upper C sand is flowing through a reduced screen size and up a tubing for several hundred metres of a quarter of the normal tubing size, plus the B sand is flowing into an effective aperture even further restricted, and due to the lower reservoir pressure and productivity of this zone it is likely to be backed out to a large extent. **Figure 6-8** below shows how the additional DP applied across the sand screens and tubing/annulus flow effects the Inflow Performance of the wells. Layers 1 & 3 are the inflow performance of the B and C sands at pressures immediately inside their sand screens. Therefore, for a very small reduction in pressure large flow can be induced to flow into the wellbore. However, the overally inflow performance is much poorer. It shows for relatively small gas rates the pressure reduction required to be applied at the top of the two sets of sandscreens. This is because the frictional drop in the sand screens must be applied before calculating the inflow pressure inside the B or C Sand screens.

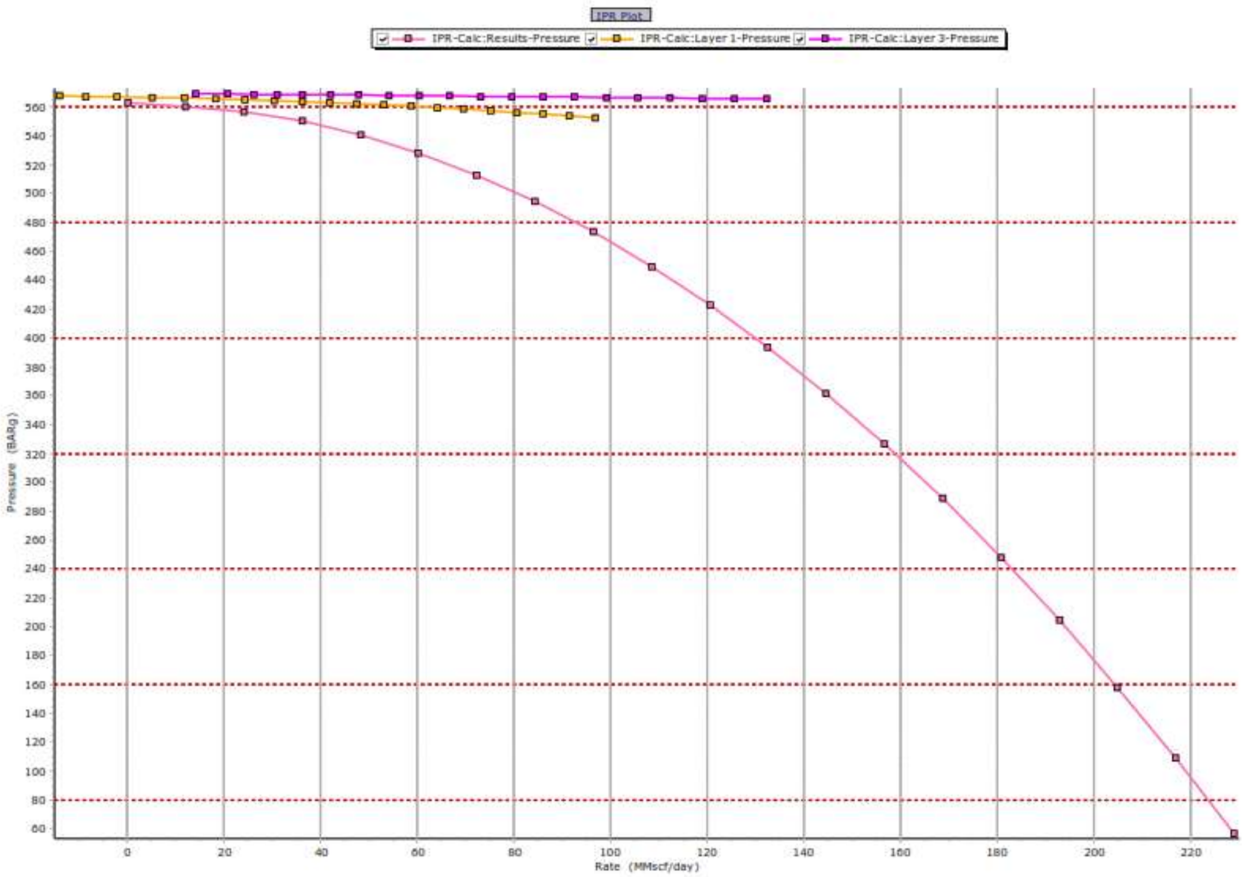


Figure 6-8 – Inflow Performance Relationship of B-Sand (Layer 1) and C Sand (Layer 3) plus full inflow relationship at top of Sand Screens

Finally, **Table 6-6** shows minimal difference between the KM Base Case with 7" tubing completion design with that design where the OHGP is lengthened to produce directly from the Lower C concurrently with the Upper C. Surprisingly, production rates are lower for the longer OHGP, this is likely due to friction and additional back out caused by higher pressure, lower productivity sands increasing the flowing bottom hole pressure witnessed by the Upper C sands.

6.7.1 Predicted Flowing Wellhead Temperature

Work performed for Karish Main on anticipated flowing wellhead temperature demonstrates that a Full Enthalpy Prosper model provides results consistent with Wellcat thermal modelling (the industry standard). Real measurements from the KM02 well clean-up have also demonstrated that the values predicted by Prosper are reasonable. Therefore, a Full Enthalpy Prosper model of the Karish Main 7" Tubing Base Case Completion design was built in order to assess the Flowing Wellhead Temperature under and range of flowing conditions.

From the figures below (**Figure 6-9** & **Figure 6-10**) it can be seen that the FWHT at rates> 25 mmscfd (minimum stable flow rate predicted by Prosper) the FWHT will be above 50degC and at anticipated abandonment rates and WGR, the temperature is well above 55degC.

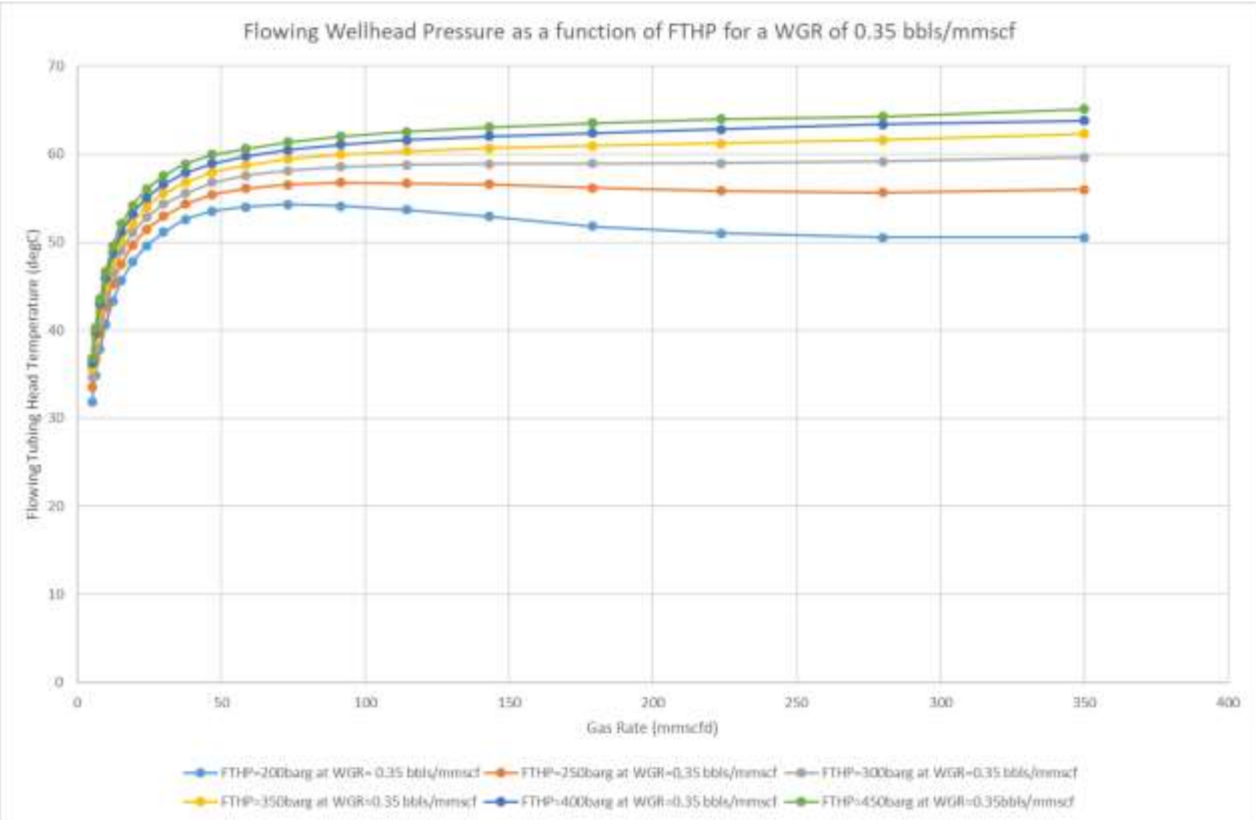


Figure 6-9 – Flowing Tubing Head Temperature (FTHT) as a function of FTHP for a WGR of 0.35 bbls/mmscf

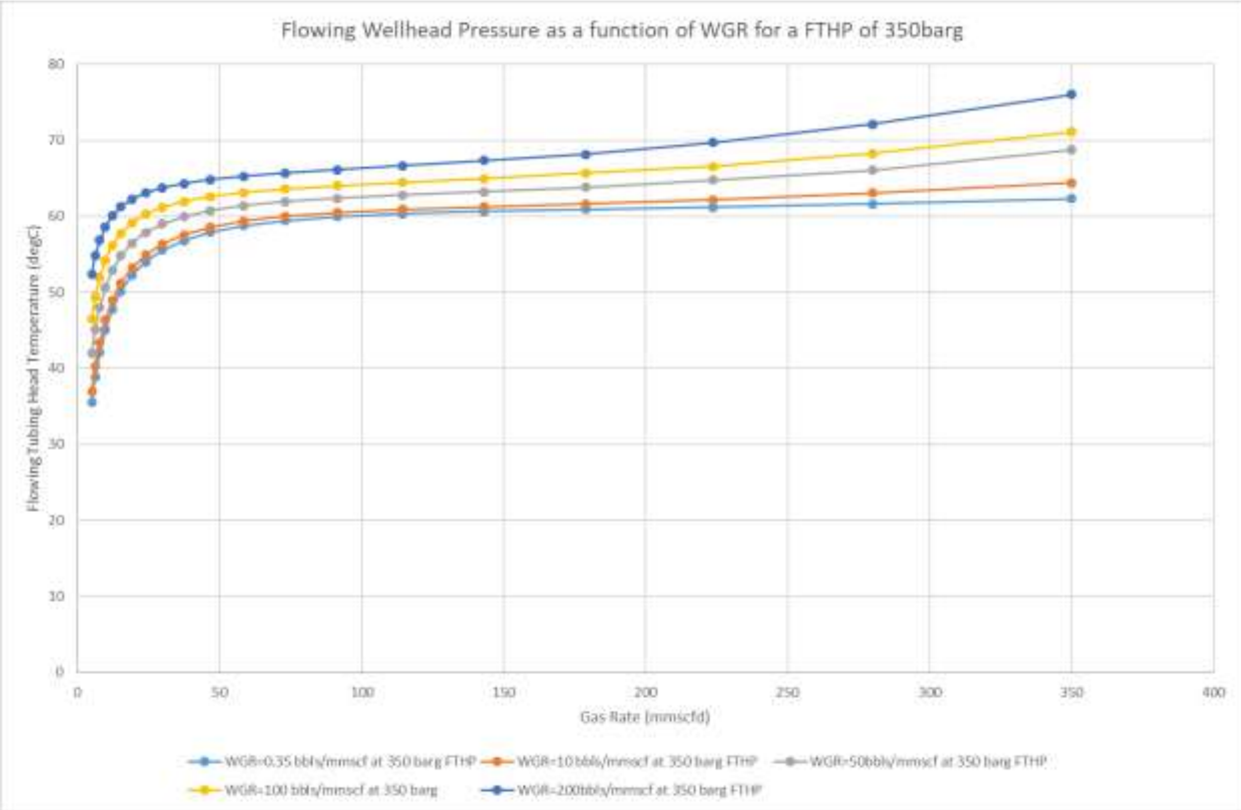


Figure 6-10 – Flowing Tubing Head Temperature (FTHT) as a function of WGR or a FTHP of 350 barg

6.8 Reservoir Simulation Model Description

A dynamic reservoir simulation model was built in Eclipse 300 (Compositional) based on the latest Petrel geological model, i.e. KNCD_MAR_01. The fine layered geological Petrel model was upscaled to 47 layers before being used in the Eclipse model. The number of grid blocks in the x and y direction were the same as in the fine grid and upscaled Petrel model (221 x 91) with a grid dimension of 100 m in the x and y direction. The layering scheme utilised in the Eclipse 300 model is shown in **Table 6-7** below.

	Top Layer	Bottom Layer
Above A Cropped Cleaned [Converted] (TWT 2) (Depth 1) - Top B Sand	1	1
B4 Shale	2	2
B3 Sand	3	3
B3 Shale	4	4
B2 Sand	5	5
B2 Shale	6	6
B1 Sand	7	7
B1 Shale	8	8
Upper C6 Sand	9	11
Upper C5 Sand	12	13
Upper C4 Sand	14	15
Upper C3 Sand	16	17
Upper C2 Sand	18	19
Upper C1 Sand	20	21
Lower C10 Sand	22	23
Lower C9 Sand	24	25
Lower C8 Sand	26	26
Lower C7 Sand	27	31
Lower C6 Sand	32	33
Lower C5 Sand	34	35
Lower C4 Sand	36	37
Lower C3 Sand	38	39
Lower C2 Sand	40	41
Lower C1 Sand	42	42
CD Shale Upper	43	43
CD1 Sand	44	44
CD Shale Lower	45	45
D1 Sand	46	46
D2 Sand	47	47

Table 6-7 Layering in Eclipse 300 Simulation Model

Data from analogue fields in the area, indicates that a strong aquifer is likely to be present in the north area of the Karish Field. This strong aquifer was modelled by multiplying the volume of the grid cells highlighted in blue at the Northern edge of the grid to create an aquifer volume 100x the volume seen in the gas accumulation (see **Figure 6-11** below). This method was tested against other approaches such as the use of a numerical Carter-Tracy aquifer and extension of the grid cells to explicitly model the water filled reservoir section within this area. Results showed no significant variations in recovery. Therefore, in order to improve run times, the simplest method of defining the aquifer by multiplying the pore volume of cells at the edge of the structure was utilised in the works presented in this document.

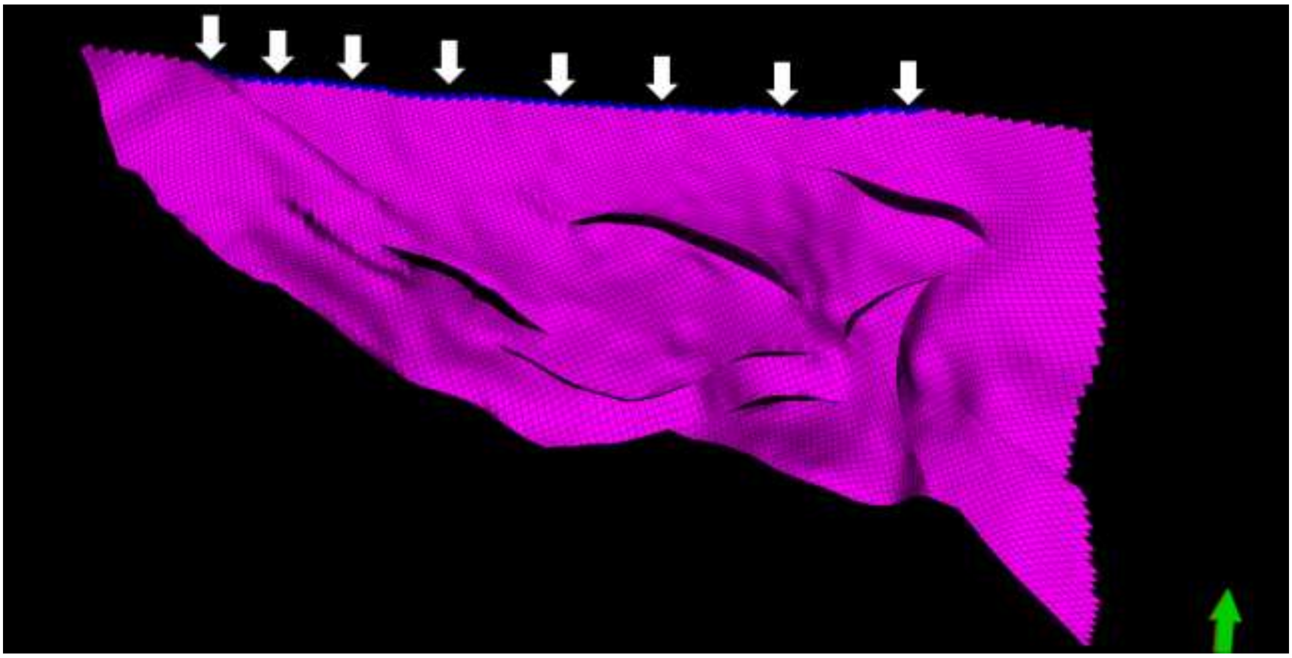


Figure 6-11 - Location of Aquifer in Simulation Model

All porosity, permeability and water saturation arrays were imported directly from the Petrel Model (see **Figure 6-12**, **Figure 6-13** & **Figure 6-14**) with the Simulation Model initialized and the endpoint scaling option applied to the relative permeability curves.

The rock compressibility was defined at 1 x10 -6 /psi based on the available experimental data (see section 6.1). However, given that the gas compressibility is some two orders of magnitude higher, the rock compressibility will have minimal to no impact on recovery.

The trapped gas saturation to water value assigned in the base case runs was 20 % based on the lower end of a range defined from literature (20-40%). A sensitivity assuming a lower value of 15% was performed which is presented below. In order to define a Karish North specific value laboratory SCAL experiments are underway and once these are available the model will be updated to assess the impact of these experimental results on predicted recoveries and profiles.

For the assignment of the fluid properties the reservoir was divided into 4 PVT Regions based on the sand units and depth as show in **Table 6-8**, while the 27-component "Peng-Robinson78" EOS model developed by AFS presented in section 6.5 was assigned to define the fluid properties by region.

PVT Regions	Unit	Location	Composition, PVT Sample	Flash CGR, stb/MMscf	Liquid Yield stb/MMscf
1	B Sand	Layer 1-8	Sample 6.1	8.9	13.9
2	Upper C Sand	<4720m TVDSS	Sample 5.1	27.4	42.7
3	Lower C Sand	>4700m TVDSS <4765m TVDSS	Sample 3.3	33.5	52.1
4	CD Shale	>4765m TVDSS	Sample 2	71.5	111.3

Table 6-8 – PVT Regions Used in the E300 Simulation Model

The simulation model only considered the Upper C, Lower C and D sands, which contain most of the initial produced potential in this part of the Karish lease. A simulation model of the B sand has been constructed separately with results described below in section 6.9.

Examples of the porosity, permeability and saturation maps are given in **Figure 6-12**, **Figure 6-13** & **Figure 6-14**, while the PVT regional breakdown in the simulation model is shown in **Figure 6-15** below.

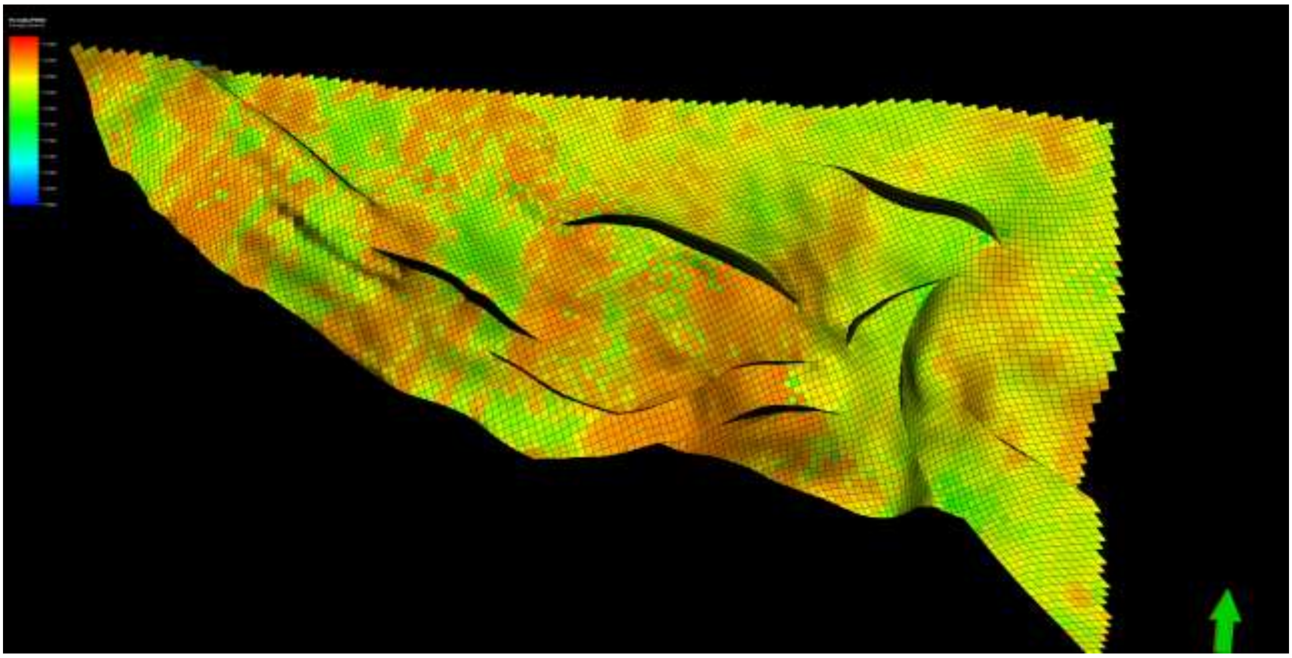


Figure 6-12 – Porosity Array in Simulation Model

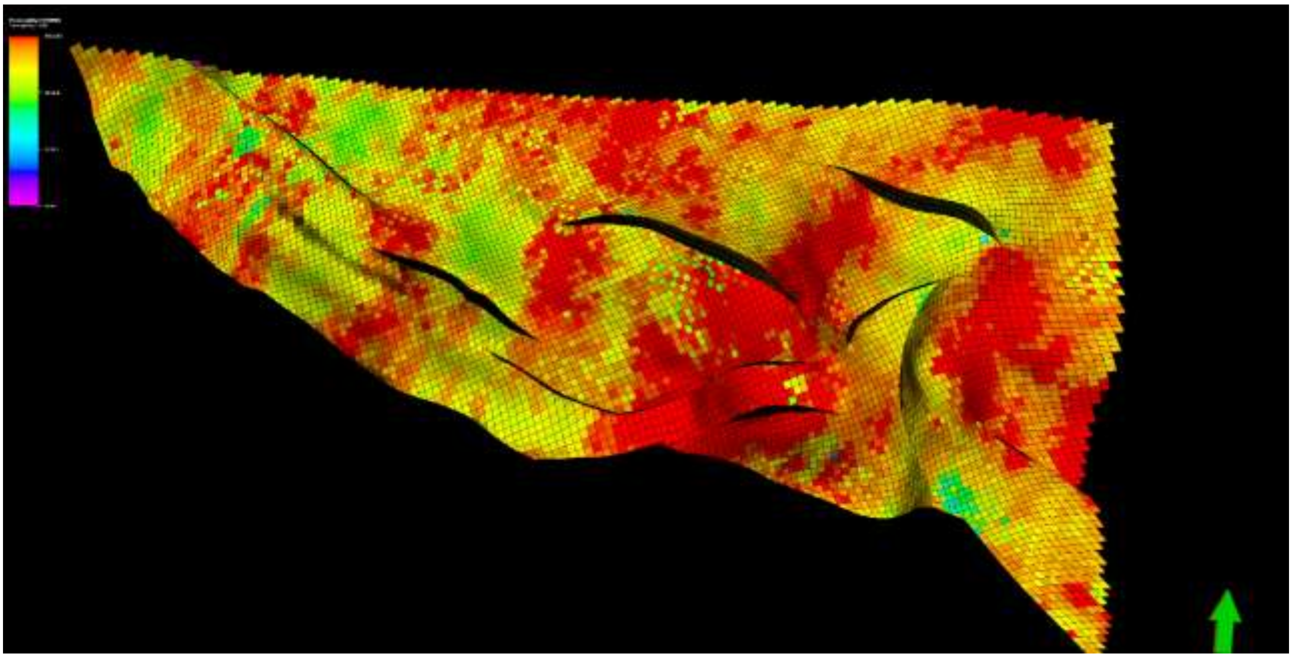


Figure 6-13 – Horizontal Permeability Array in Simulation Model

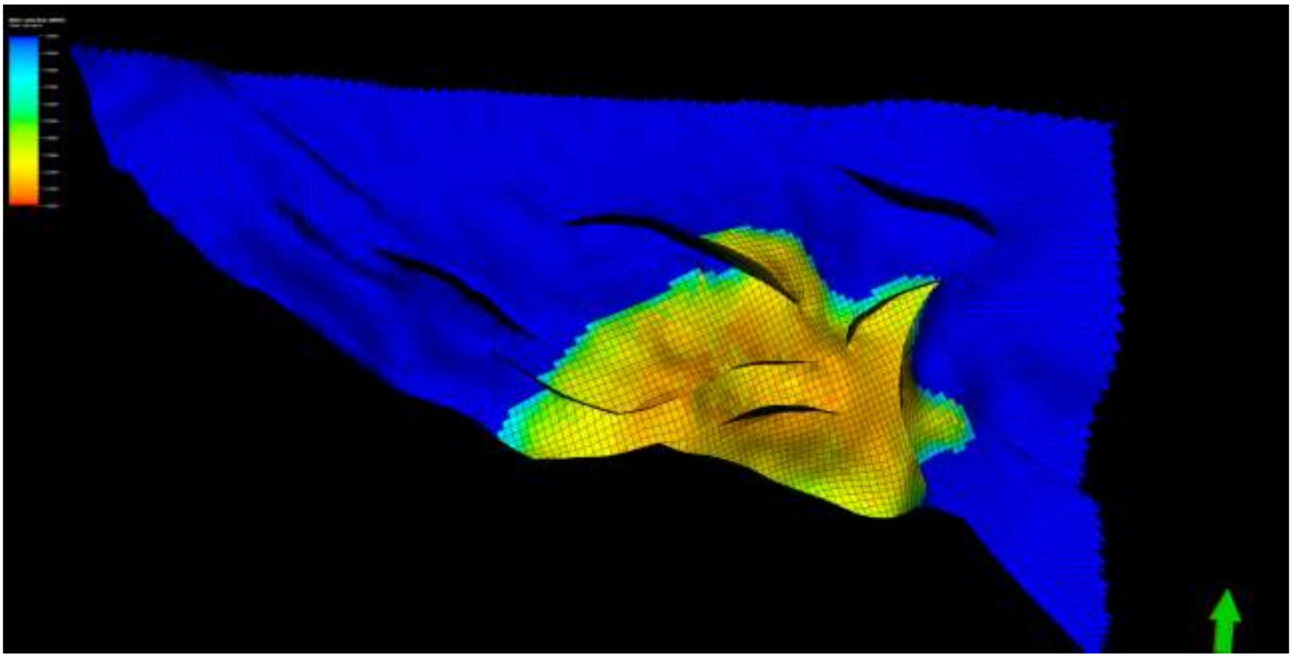


Figure 6-14 – Initial Water Saturation Array in Simulation Model

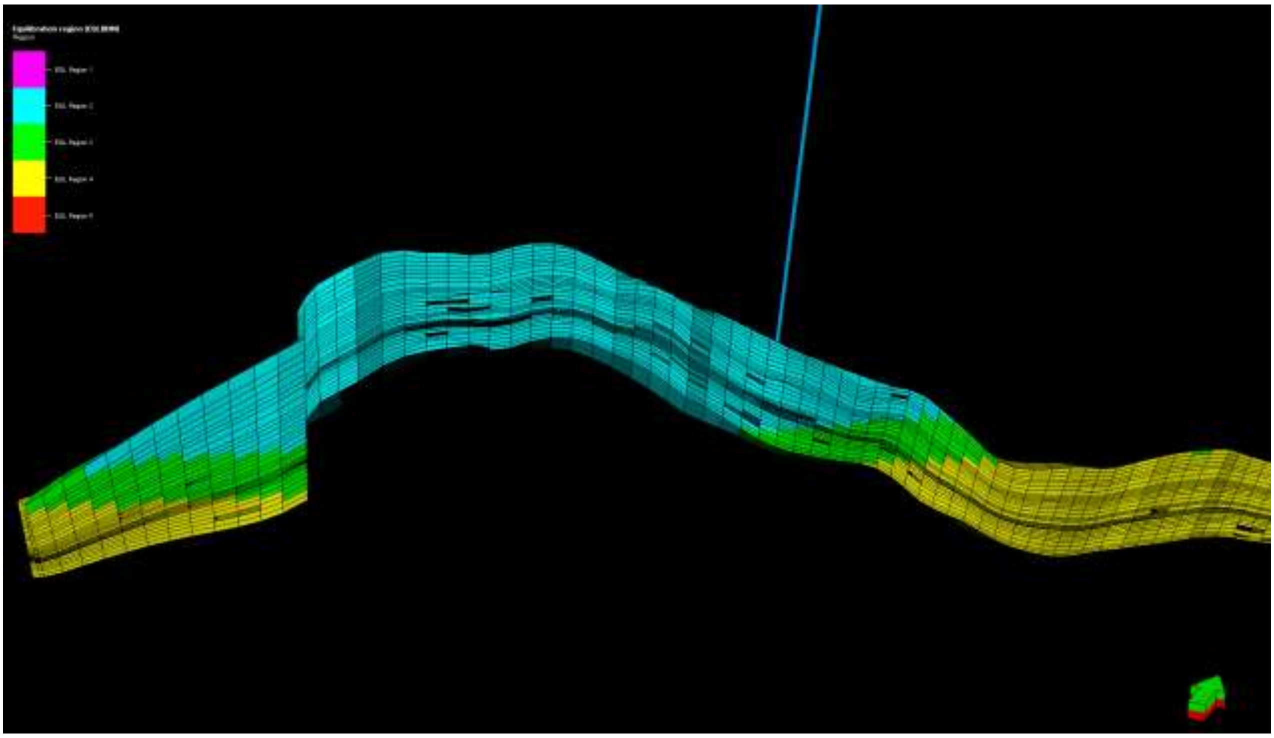


Figure 6-15 – PVT Regions in the Simulation Model (sample 5.1 blue, sample 3.3 green and sample 2 yellow)

The completion philosophy adopted matched that employed in the Karish Main development wells with the Karish North wells completed within just the top 35 m of the Upper C sand and no mechanical skin based on the performance of the KM02 welltest clean-up and the reference well design concept (see section 7.2.4 below).

Constraints applied to the wells and field within the Simulation Model include:

- Individual well gas production rate limited to 200 MMscf/d based on TFMC stated design rate for the single line tieback option
- Field wide water production rate limited to a maximum of 4000 bwpd (in line with FPSO design capacity)
- No FWHP restrictions were applied, instead the surface network was modelled by VLP curves to the inlet separator pressure at the FPSO, with all cases run using a single line tied back to the Karish Main Manifold (Facilities Option A-3)
- A range of FPSO arrival pressures were considered during the modelling ranging from 250 to 180 Bara (note: the capacity of the FPSO at an arrival pressure of 210 Bara has been confirmed by TFMC to be 800 MMscfd, following receipt of the updated fluid properties TFMC are updating their Surface process models which will enable the minimum arrival pressure that continues to allow 800 MMscfd throughput to be calculated and the capacity of the plant at lower arrival pressures to be determined)
- No liquids constraints were applied at present, although with development options that allow higher initial rates (e.g. dual flowline tiebacks) it is likely that these constraints will be reached. For the cases presented here, however, liquid volumes from Karish North will not exceed FPSO handling capacity

The models described above are focussed on developing the C and D sands of Karish North. For the B Sand a separate model was necessary to capture more detail due to the interbedded nature of the reservoir with thin sands deposited between shale sequences (model: KN_B_MAR01). **Table 6-9** details the layers that were captured in the model and **Figure 6-16** shows the horizontal permeability distribution in one layer of the B3 sand reflecting the more disconnected nature of the sands prognosed to exist within this unit with areas of zero permeability presenting a more complex flow path into the well. The Gas-Water Contact has not yet been identified in the B sand, but was assumed to be the same as the Karish North C Sands.

	# Layers
Above A Cropped Cleaned [Converted] (TWT 2) (Depth 1) - Top B Sand	1
B4 Shale	50
B3 Sand	10
B3 Shale	50
B2 Sand	10
B2 Shale	50
B1 Sand	10
B1 Shale	25
Upper C6 Sand	1
Upper C5 Sand	1
Upper C4 Sand	1
Upper C3 Sand	1
Upper C2 Sand	1
Upper C1 Sand	1

Table 6-9 – B Sand Eclipse Model Layering Scheme

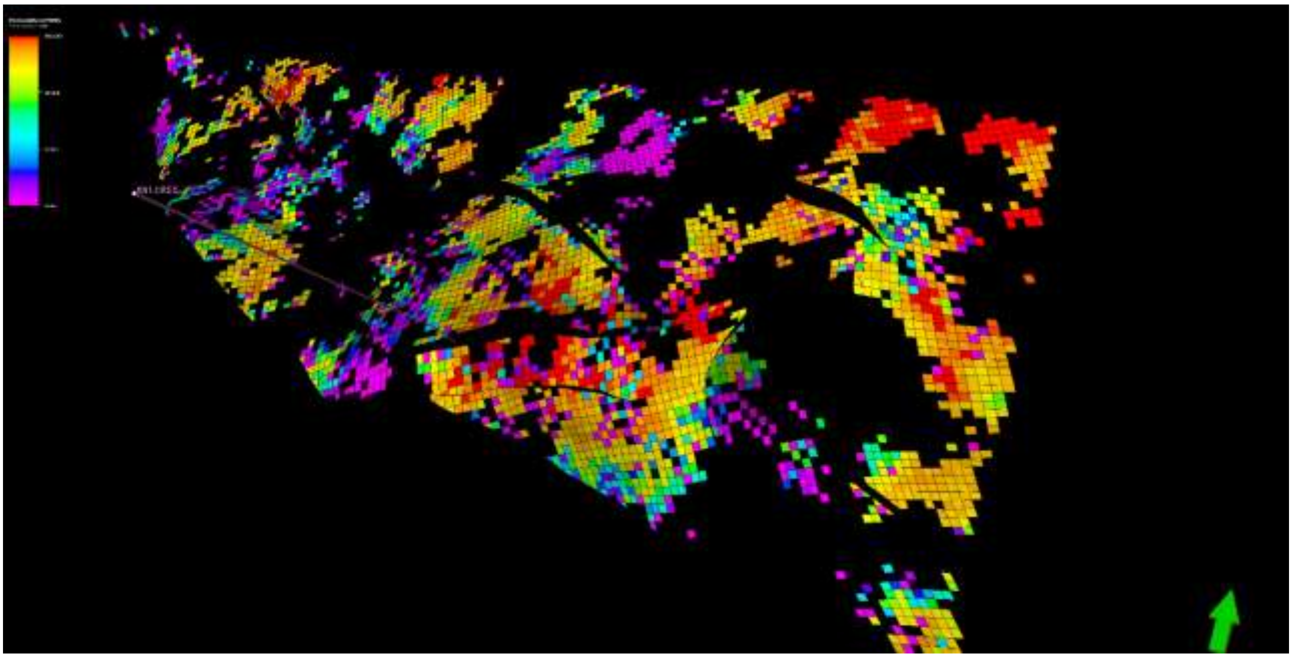


Figure 6-16 – B3 Sand Horizontal Permeability in B Sand Eclipse Model

Results from these simulation models have been used to assess the impact of different well placements, different phasing of the development wells, sensitivities around key subsurface uncertainties and more. The results of these studies are outlined in the next section.

6.9 Dynamic Simulation Results

6.9.1 C/D Sand Model

To date the main focus of the dynamic modelling has been to identify well locations and understand maximum recovery possible from the field. A number of well locations and combinations have been assessed to date. **(Note:** not all are presented here, with cases showing early water breakthrough excluded)

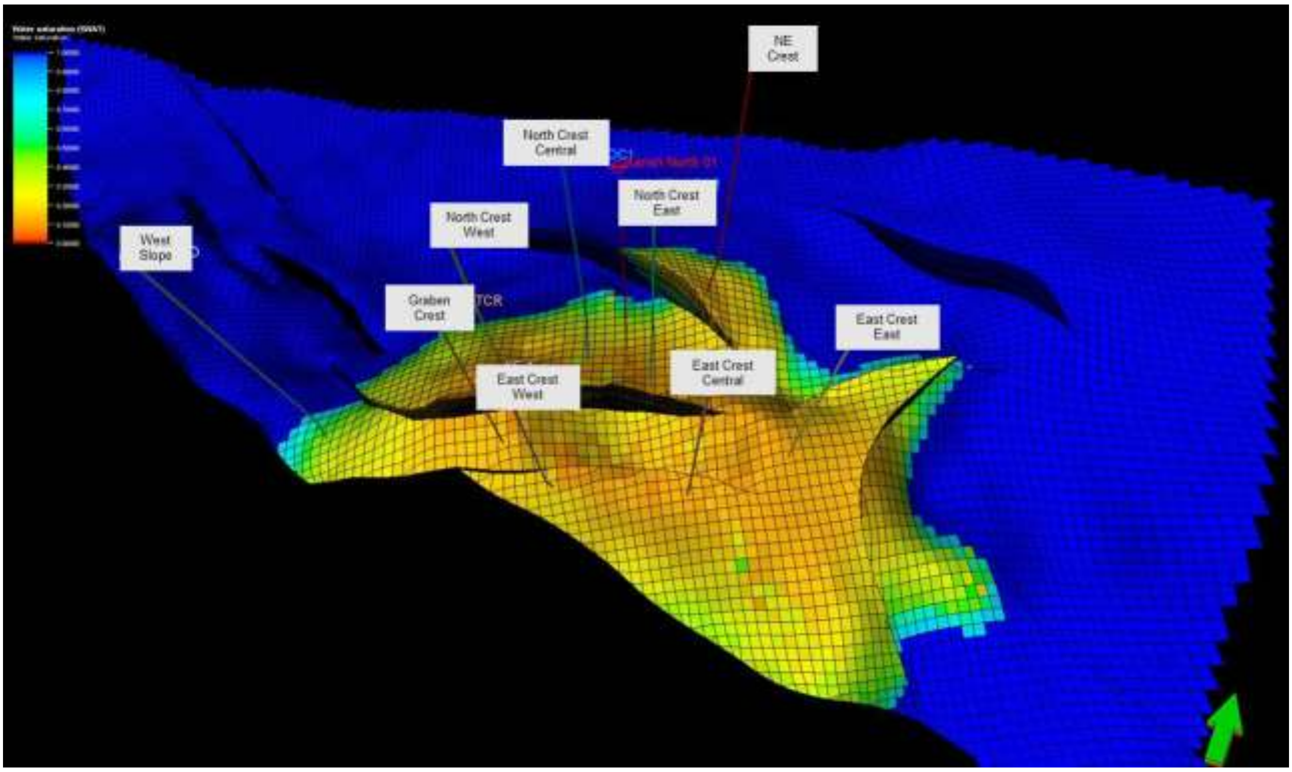


Figure 6-17 detail the locations of the wells and the combination of wells in each case.

	Case	1	2	3	4	5	6	7	8
Wells	North Crest West			X	X			X	X
Wells	East Crest Central	X			X	X			X
Wells	East Crest East		X				X		
GIIP	Reference	X	X	X	X				
GIIP	Reference but with majority of the Graben removed (as per D&M)					X	X	X	X
Sg	Trapped Gas Saturation of 20%	X	X	X	X	X	X	X	
Sg	Trapped Gas Saturation of 15%								X

(Note: not all are presented here, with cases showing early water breakthrough excluded)

Table 6-10 – Reservoir Simulation Case Matrix

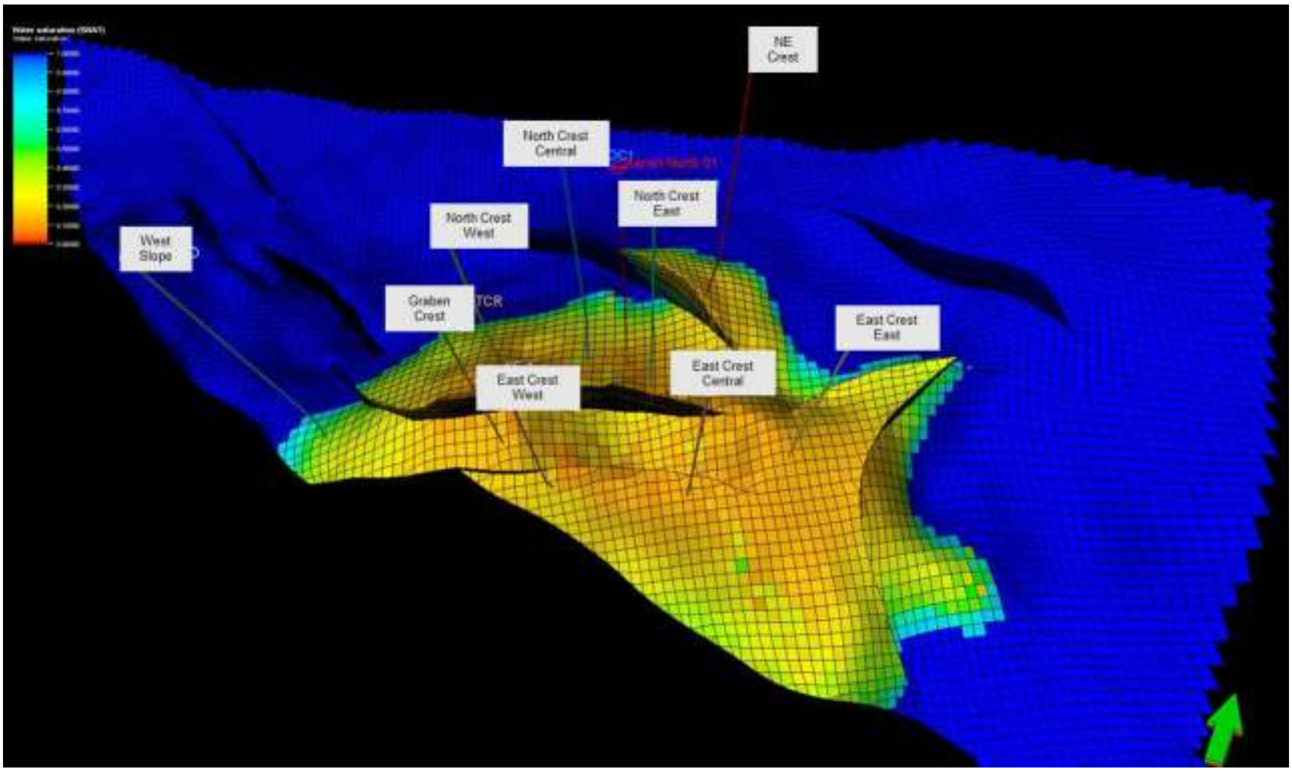


Figure 6-17 – Well Locations Tested in the Model

Case	Graben	Wells	Well Loc	Trapped Gas	Max Rate MMscf/d	Plateau Years	Cum Gas BSCF	Cum Cond MMstb	Gas Recovery Factor %
1	included	1	• East Crest Central	20%	200	10.3	1158	27.1	60%
2	included	1	• East Crest East	20%	200	9.8	996	23.8	52%
3	included	1	• North Crest	20%	200	9.5	760	17.7	43%
4	included	2	• North Crest • East Crest Central	20%	277	0	1172	27.3	61%
5	excluded	1	• East Crest Central	20%	200	8.3	1098	25.2	66%
6	excluded	1	• East Crest East	20%	200	8.5	816	20.0	49%
7	excluded	1	• North Crest	20%	200	8	675	16.7	41%
8	excluded	2	• North Crest • East Crest Central	20%	274	0	1105	25.4	67%

9	excluded	2	• North Crest • East Crest Central	15%	275	0	1222	28.3	74%

Table 6-11 – Dynamic Simulation Results

The above simulations run with and without the Graben area included replicate the model D&M have developed in which they believe the Tamar sands in the Graben area to be absent, so reducing the in place volumes by ~260 bcf.

	Eclipse GIIP (Bcf)	
	Include Graben	**Exclude Graben**
Upper C	1374	1210
Lower C	334	288
CD Shale and D Sand	212	160
TOTAL	1921	1658

Table 6-12 – Eclipse In Place Gas Volumes (With/Without Graben)

Table 6-11 shows that recovery from the Graben area is poor, even in a two-well development, therefore recovery factors assumed by D&M are higher than Energean's which include these poorly drained volumes.

It can also be seen from **Table 6-11** that the East Crest Central well location results in the highest recovery (cases 1 & 5), this is primarily because the water breakthrough is delayed compared to the other locations which lie closer to the water (see **Figure 6-11**). If the aquifer also supports the field from the Eastern edge of the model as well, then it is anticipated that this well will water out earlier and recovery will decrease. It is not yet possible to model aquifer support in this area due to the current structural model not extending sufficiently far to be able to attach a downdip aquifer, work is ongoing to allow for this upgrade.

When the North Crest well is added (Cases 4 & 8), recovery is comparable to the one well scenario. This is because the current model has no barriers between the Northern and Eastern Crests, so, over time a well placed in the Eastern Crest will eventually recover gas from all areas in the field, as it is situated on a structural high. In addition, with no aquifer located along the Eastern boundary of the field, the well does not suffer water breakthrough before it drains the Northern sections. However, the seismic suggest a number of small faults in this area that may at the very least provide a baffle to gas, and therefore reduced recovery for this well. In investigating Low and High Case scenarios, realisations with less connectivity in this area will be considered.

In terms of detailed results of the cases presented in **Table 6-11**, Case 4, that includes the entire structure, including the Graben that D&M interpret as eroded, provides the highest gas recovery. This case comprises of two wells tied back to the Karish Main manifold using a single 8" flowline, with the first well, East Crest East, online mid-2022 and the second well, North Crest, online mid-2023, this is in line with the current view of the forward development schedule although the second well may be deferred to as late as 2025.

Case 4 shows that whilst it is initially possible to produce East Crest East at 200MMscfd, when the North Crest well is brought online then both wells are cut back by the choking effect of the interfield flowline (see **Figure 6-20**). If a larger diameter flowline, or multiple lines were installed from Karish North to Karish Main Manifold it would be possible to continue to flow both wells at approaching the 200 MMscfd targeted by Eclipse. **Figure 6-20** also shows that the reservoir pressure steadily declines towards an abandonment pressure of ~470 bar, despite the strong aquifer support from the North (see **Figure 6-11**). If additional support were provided in the East of the model this decline may be arrested somewhat, however it is likely that the East Crest Central well will suffer water breakthrough several years before 2035.

Case 4 also shows the effect on liquids yield over time (see **Figure 6-19**). Initially the liquid yield increases as richer fluids from deeper in the reservoir are produced by the wells, in particular the North Crest well. When this well is shut-in due to water production, the liquid yield drops as the East Crest Central well is higher in the structure. Liquid yield continues to drop as the reservoir pressure declines and further liquid drop-out occurs in the reservoir.

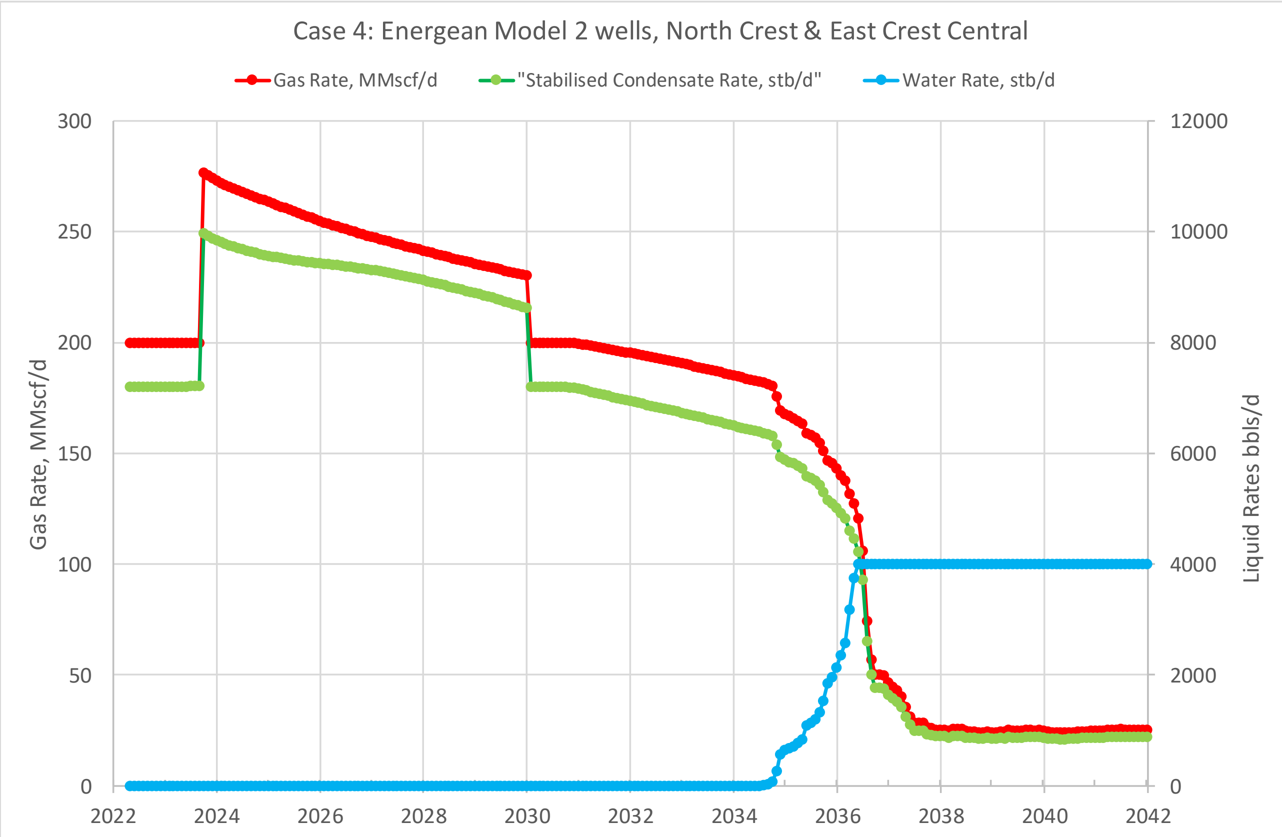


Figure 6-18 – Case 4 Production Rates

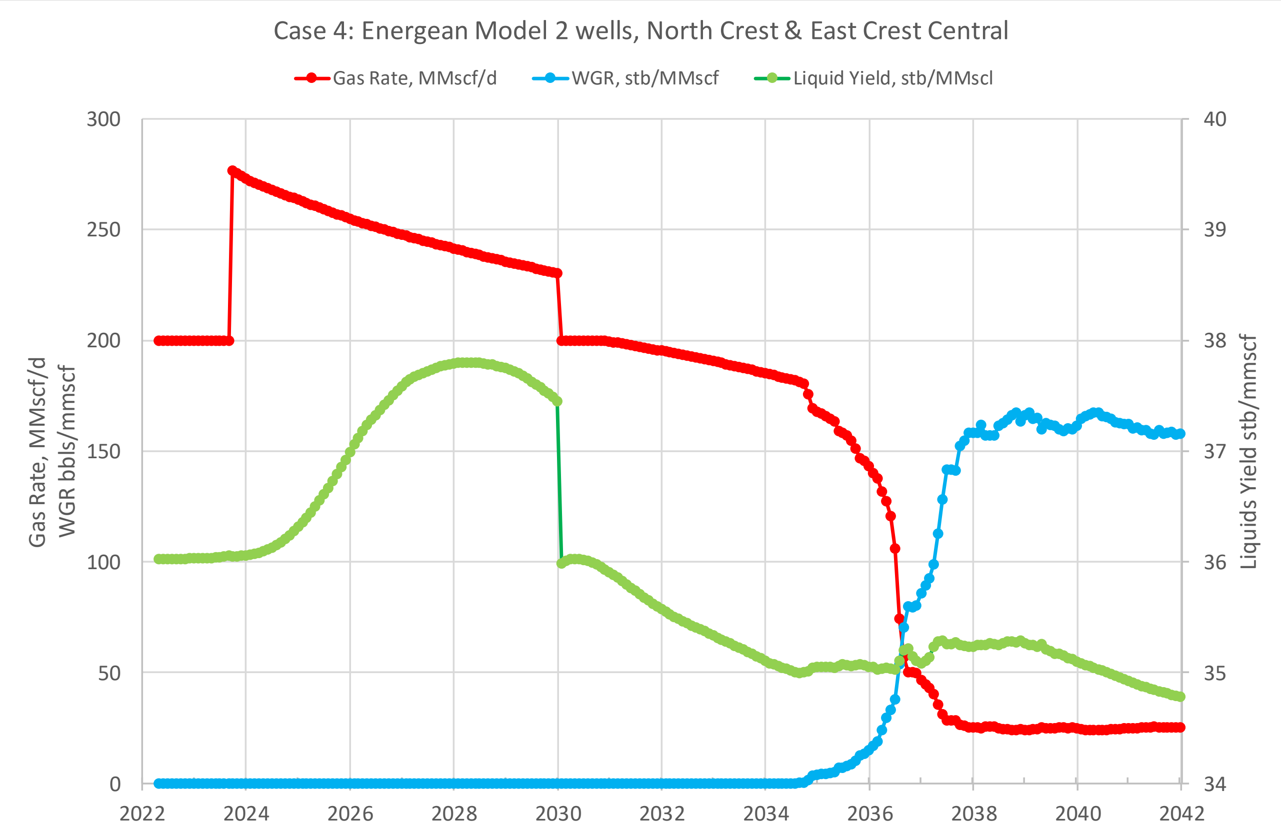


Figure 6-19 – Case 4 Liquid Yield and Water Gas Ratio

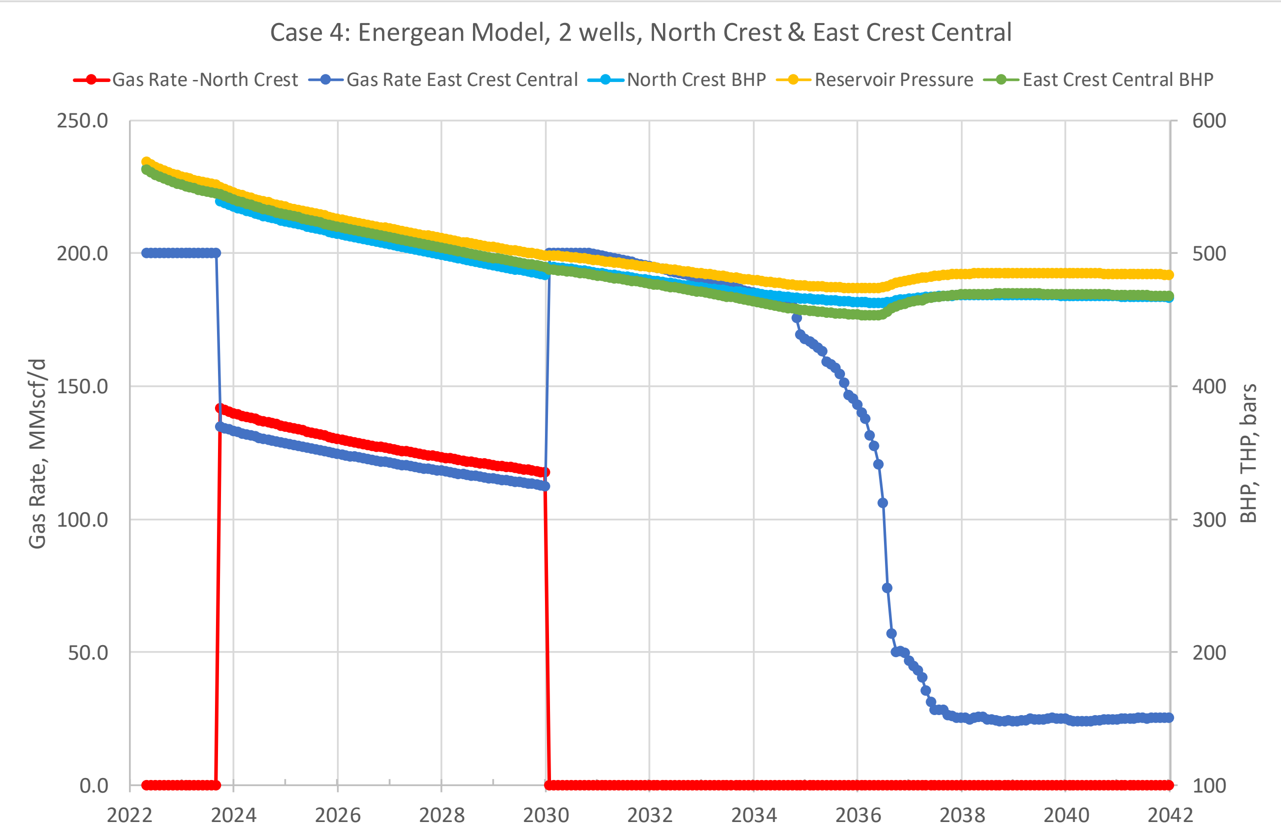


Figure 6-20 – Case 4 Individual Well Rates, FBHP and Reservoir Pressure

Results for the KNCD_MAR_01 reservoir simulation models show recovery for the C/D-sands in the range 61-74% for a two-well development depending on well locations, individual well water breakthrough timing and trapped gas saturation.

As additional information from the SCAL studies becomes available, and with a more detailed understanding of the eastern area and the aquifer size and connection, these model results will be updated and a revised range of recoverable volumes defined.

6.9.2 B-Sand model

For the B-sand model (KNB_MAR_01), a single well at the East Crest Central location was considered to be completed using a Cased Hole Gravel pack across the B Sand. All well and field constraints were as per the C/D sand model. **Figure 6-21** shows the profile for this well, which assumes rapid well production decline and water breakthrough. The ultimate recovery is 175 bscf, which equates to a recovery factor of 42%.

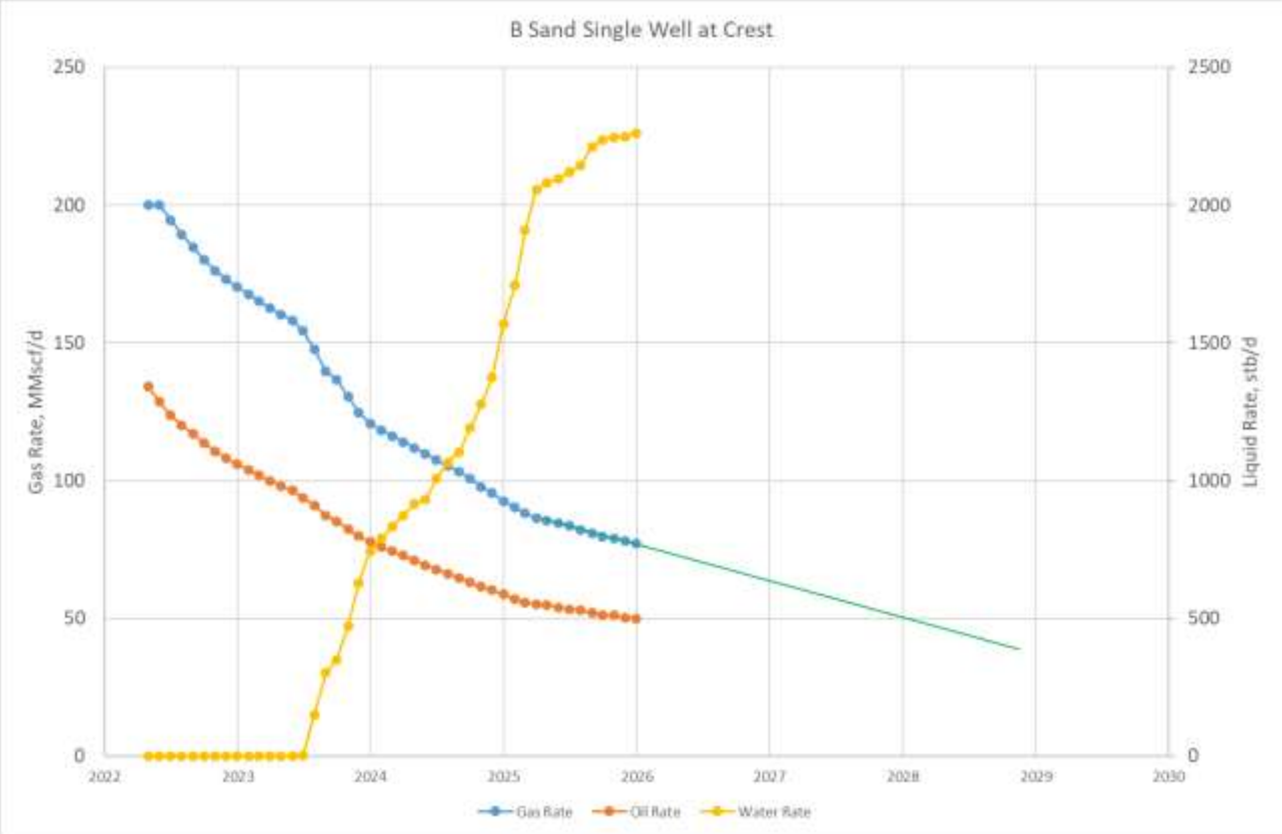


Figure 6-21 – B Sand Production Profile

6.10 Reservoir Management Plan

Karish North will be produced by natural depletion, but there is likely to be moderate to strong aquifer support, which will help maintain reservoir pressure.

The production from Karish North will supplement the production from Karish Main, which will be brought online approximately twelve months earlier and has a higher GIIP. The base case assumes that production from Karish North will be used to satisfy the volumes sold under new GSAs with Karish Main satisfying those GSAs signed before the CPR of 30th June 2019. This allows the additive value of Karish North to the already approved Karish Main development to be calculated. However, it is likely that production from Karish North will be prioritized over that of Karish Main (within the liquids handling capacity of the FPSO) in order to benefit from the higher liquid yield of Karish North fluids.

Monitoring of the wells will be performed using the following items:

- individual well wet gas flowmeters
- individual well sand detectors
- downhole pressure and temperature gauges
- wellhead pressure and temperature gauges,
- manifold pressure and temperature gauges,
- FPSO arrival pressure and temperature gauges,
- Primary separator flowmeters, pressure and temperature gauges

When combined with calibrated well models, this will enable the flowing bottomhole pressure and pressure differential across the OHGPs to be monitored to ensure that it is not exceeding 100 psi, the level at which failure of the OHGP becomes more likely. Reservoir pressure will be monitored using analysis of opportunistic well shut-ins, e.g. for SCSSV function tests. The monitoring will also allow water production to be allocated to individual wells that in conjunction with reservoir simulation will allow calibration of predicted water breakthrough at all wells.

7 Facilities and Well Engineering

7.1 Facilities

Karish North will be tied back to the Energean Power FPSO which is scheduled to be installed and providing sales gas to Israel by mid-2021. All installation activities are scheduled to commence on the Karish North development after First Gas from Karish Main.

Tie-in of a Karish North discovery was considered in the Karish and Tanin Field Development Plan, see **Figure 7-1** below when the Karish North tieback was sized for a peak production of 200mmscfd with the Karish North Fluids routed through one of the 10” risers from the Karish Main Manifold to the FPSO. The fluids and reservoir conditions in Karish North were also assumed to be the same as Karish Main.

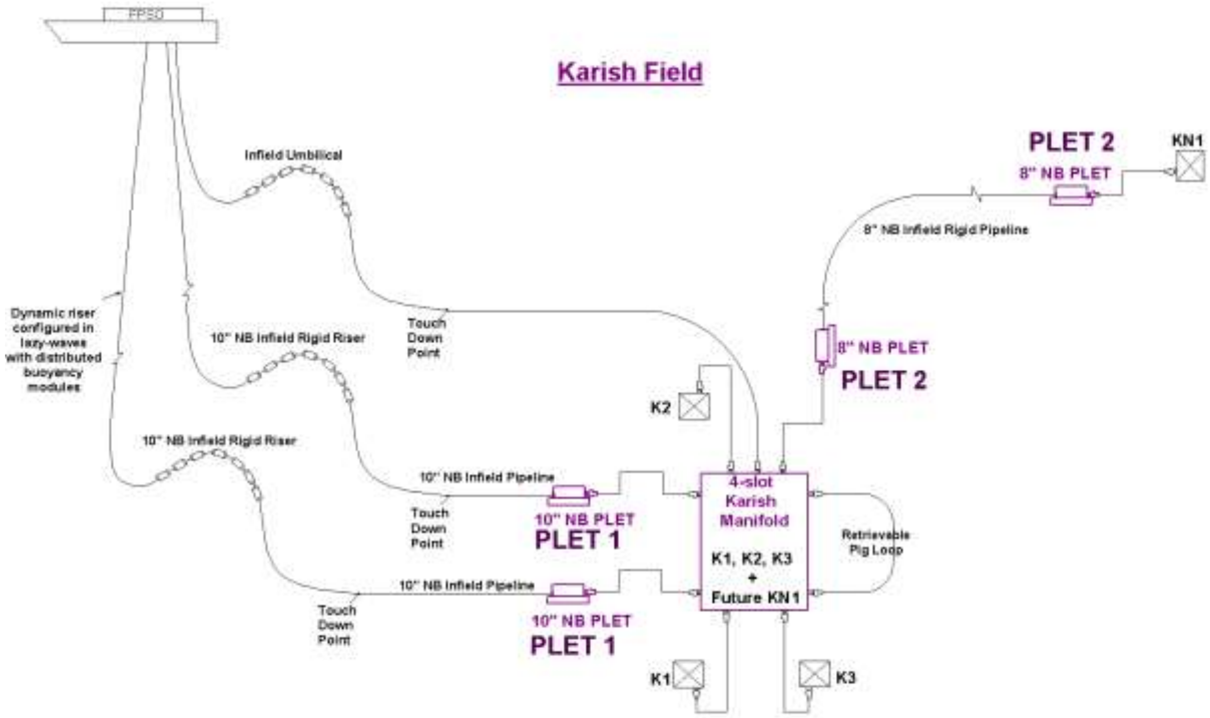


Figure 7-1 – Karish North Development as Envisaged at the June 2017 FDP Submission for Karish

Since the initial FDP was submitted the following has changed in terms of Energean's view of how Karish North will fit in to the overall development:

- Karish North C-Sand Fluids have higher liquid yields (34-38 bbls/mmscf varying over field life predicted by dynamic simulation mode, see **Figure 6-19**) and they also have measurable wax content
- Karish North Reservoir Pressure of 566.6 barg at 4512 m TVDSS (datum depth for Karish Main & North fields) versus the 542.9 bara used by TFMC for the preliminary design
- Karish North FWHT for dry fluids at 200mmscd of 63.8 deg C versus 56 degC used by TFMC for the preliminary design
- Sales Gas Contracts are anticipated to match the FPSO capacity (8.3 BCMA) during field life

These changes mean that the original FDP design of a 5.5km 8" ND wet insulated flowline is being revisited, in order to provide >200 mmscfd capacity at the higher CGRs. These concepts are discussed in section 7.1.1 below.

7.1.1 Development Concepts Under Consideration

Energean followed the stage gate process to Concept Select level as per the original FDP. This commenced with a Framing Session in May 2019 where a number of key decisions were defined regarding development of the field, see **Table 7-1** below. For each key decision regarding the development a number of options were developed that were assessed against the selection key selection criteria, or value drivers, identified:

- Economic performance (NPV, P/I, CAPEX)
- Maximised recovery: both gas and liquids
- Maximising capacity of Karish Main + Karish North to achieve FPSO design throughput
- Low operational complexity

	KEY DECISIONS- CONCEPTUAL STAGE			
	1	2	3	4
	Completed Intervals	Subsea Facilities	Wells	Maximum Subsea Capacity
A	Single zone- workover to produce B sands 7" Tubing	Single line tied back to Karish Main Manifold well slot	2	2 BCMA
B	Single zone- workover to produce B sands 5.5" Tubing	Dual line tied into to KM Manifold pigging loop tie-ins	3	4 BCMA
C	OHGP across two zones 7" Tubing	Dual line tied back to FPSO via new riser(s)		
D	SMART well Completion of B & C Sands 5.5" Tubing			

Table 7-1 – Development Decisions Outstanding

The completion concepts are discussed in section 7.2.3 below. The remaining decisions all relate to the capacity of the subsea system.

Increasing production capacity for Karish North to 4 BCMA (387 mmscfd) will require both:

- A reduction in minimum FTHP
- A second development well in the Karish North structure

It is likely that final subsea capacity will be above 2 BCMA but below 4BCMA, a final decision will be made before FID; the subsea options discussed below allow for this range.

The FTHP can be reduced by:

i. Increasing the area available to flow for KN fluids by providing a second flowline, either to the KM Manifold or direct to the FPSO. This is allowed for by either of the dual tieback options that will be described in sections 7.1.1.3 & 0 below.
ii. Reducing the arrival pressure at the FPSO. **Figure 6-4** demonstrates what can be achieved for 210 barg, which is the lowest arrival pressure considered by TFMC in their process simulation modelling of the FPSO. It is likely this pressure can be reduced further, although to what level without impacting on FPSO processing capacity and sales gas spec is not yet known. It may also be possible to reduce arrival pressure by installing booster compression on the FPSO, although the impact of this on velocities in the subsea system and the ultimate benefit in terms of FWHP may make this option unattractive.

7.1.1.1 Concept under Consideration

The subsea tieback options considered come under three main designs (see **Table 7-1**)

A. Single Line Tie-Back to Karish Main Manifold Well Slot
B. Dual Lines Tie-Backs to Karish Main Manifold Pigging Loop
C. Dual Lines Tie-Backs to the Energean FPSO via New Riser(s)

For these options a number of sub-options have been defined detailed in **Table 7-2,** including a hybrid option recently proposed that ties dual lines into the fourth well slot on the Karish Main Manifold.

	A- Single Line Tieback	Hybrid A/B: Dual Lines tied back to KM04 well slot	B- Dual Lines tied back to KM Pigging Loop	C- Dual Lines tied back to FPSO
1	A-1 Single line routed besides KN01 and KN02 locations with KN01 tied in using In-Line Tie-in (ILT)	A/B 8" and 6" line tied back to KM Manifold, lines merged and tied-in at KM04 well slot	B-1 Dual Lines tied back to KM Manifold Pigging Loop connector (relocated to Karish North	C-1 Dual Lines tied back to FPSO, deviated KN02

			Manifold), deviated KN02	
2	A-2 Single Line tied back to KN01, KN02 deviated well		B-2 Dual Lines tied back to KM Manifold Pigging Loop connector (relocated to Karish North Manifold), vertical KN02 well connected by dedicated flowline	B-2 Dual Lines tied back to, vertical KN02 well connected by dedicated flowline
3	A-3 Single Line tied back to KN01 with KN02 vertical well connected by dedicated flowline			

Table 7-2 – Subsea Facilities Options Under Consideration

Those options that will be discussed in some detail are highlighted in **Table 7-2**. All cases consider KN02 to target the North East Crest of the field, a location requiring a step-out of ~1.1km which is equal to the largest step-out of any of the well locations investigated to date. Therefore multiple cases have not been developed considering each well location separately.

7.1.1.2 Single Line Tieback Options

TFMC have previously prepared costs and indicative schedule for a single line tieback to the Karish Main remaining well slot. In essence this is the same as Concept A-3, but there was a little less detail on the connection to the second well.

At present an 8” Nominal Bore Rigid flowline (ID= 7.2”) with wet insulation (U=3.7W/m2K) from a KN01 located East PLEM is assumed for all single line tieback options. This is based on the well being connected at the remaining slot on the KM manifold, a connection that has a restriction of 4.9”. **Figure 7-2** below, shows the layout of the Karish Main Manifold production flow paths with KN01 connecting in at the spare slot on the manifold using a similar multibore spool containing hydraulic, electrical and chemical injection requirement to that used by the Karish Main wells to connect the manifold to the XT. This multibore spool then connects into a Western PLEM close to the Karish Main manifold that separates all hydraulic/electrical/chemical services into an umbilical with the production bore being as described above.

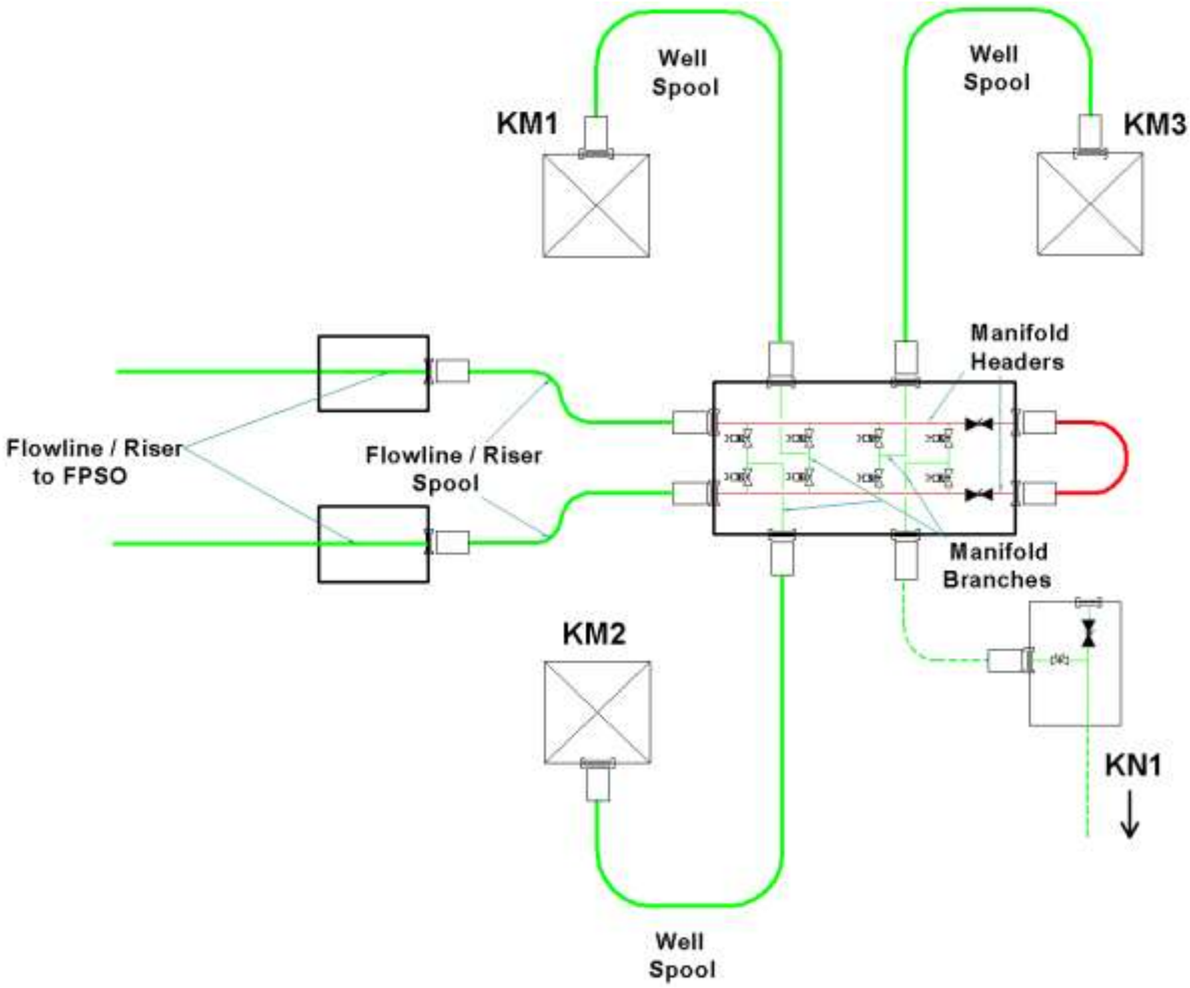


Figure 7-2 – Layout of Karish Main Manifold Showing connect of KN01 Flowline

7.1.1.2.1 Concept A-1 Subsea tieback by single flowline with ILT incorporated for KN01 well

This concept consists of a continuous rigid flowline from KM Manifold to be laid past KN01, terminating at a PLET besides KN02. KN01 will be tied in using an inline tee (ILT). This allows for both KN01 and KN02/KE to be installed in a single major offshore pipelay campaign, with only an MSV required for tie-in of a second well drilled after first gas. The field schematic is shown in **Figure 7-3** below where all facilities which could be deferred until a second campaign are greyed out (note: the second campaign facilities are greyed out in all subsequent concepts).

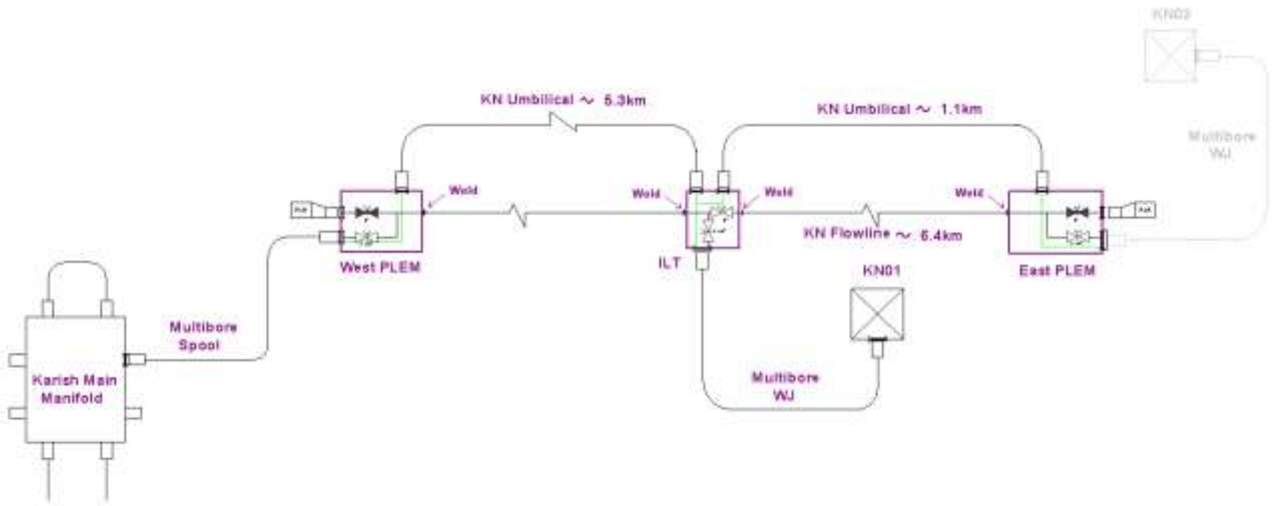


Figure 7-3 – Concept A-1 Schematic

Other features of this concept are that:

- All three structures may be installed inline with the pipeline
- the ILT installed to allow tie-in of KN01 includes a header valve for phasing of KN02 installation
- the West and East PLEMs will allow for subsea pigging for pre-commissioning using 2x subsea PLRs, other concepts including dewatering via flushing from the service line are under consideration that could eliminate the requirement for these PLRs
- For this concept the East PLEM is installed close to the anticipated KN02 location, as opposed to KN01

Advantages	Disadvantages
Only 1 major offshore pipelay campaign required	Pre-investment in additional line pipe and extra structure (ILT)
If KN02 is drilled as a vertical well at 1.1km from KN01, then this option is cheaper overall than option with second pipelay campaign	In deviated well option for KN02 there are no benefits for this option
Increases line size, and hence reduces pressure drop, from KN02 to KN01	Requires decision on KN02 location by June 2020
	Increased scope required for 2 x PLRs (although may be avoided)

Table 7-3 – Concept A-1 Advantages and Disadvantages

7.1.1.2.2 Concept A-2 Subsea tieback by single flowline both wells located near East PLEM

This concept uses multibore spools as both the KN01 and KN02 XTs are located near the East PLEM with the KN02 target reached by deviated drilling.

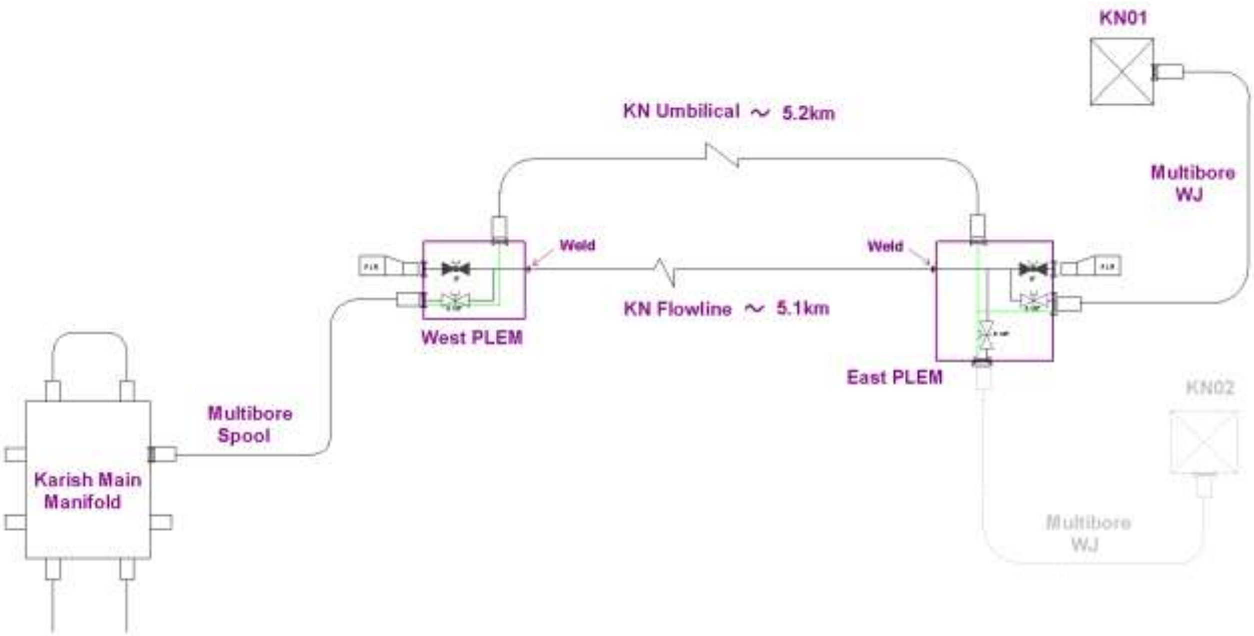


Figure 7-4 – Concept A-2 Schematic

Other features of this concept that differentiates itself from A-1 are that:

- both structures may be installed inline with the pipeline
- the architecture allows for a decision to be made on whether KN02 is deviated or vertical (or indeed in a totally different location) at a later stage than FID- the only pre-investment required for a future KN02 campaign is an additional multibore hub on the East PLEM

Advantages	Disadvantages
No major pre-investment required for KN02	Cost and risks of deviated drilling
KN02 location can vary until sanction of second well	Increased scope required for 2 x PLRs (although may be avoided)
Simplest and therefore lowest CAPEX option	

Table 7-4 – Concept A-2 Advantages and Disadvantages

7.1.1.3 Dual Line Tieback to KM Manifold Options

The dual line tieback to the Karish Main Manifold provides additional flow area. A review was conducted of locations to tie-in dual lines and the only location that TFMC could identify was at the pigging loop connections on the Karish Main manifold.The only alternatives to tying in at this location would be:

a) Merging the two flowlines at a PLEM which then connects by a 4.9” ID multibore spool to the spare slot on Karish Main: This was rejected as it would cause significant pressure drop at that inlet point and diminish significantly the benefits of a dual flowline
b) Adding an extension manifold of two slots onto the Karish Main manifold, to tie-in the two flowlines. This seems a large increase in structures required for an option that will still restrict flow at tie-in to the manifold compared to tying in at the 8” ID Karish Main Manifold Header

Therefore, all concepts reviewed by TFMC consider tie-in at the pigging loop connections of the Karish Main Manifold Headers (see **Figure 7-2** above). However, all designs are also allowing for round trip pigging functionality to be retained, initially with the flowline and jumper sizes to Karish North matching that of the Karish Main Manifold and Risers, i.e. 10” Nominal Bore (8” ID). The costs savings of reducing the line size to 8” NB or utilizing standard 10” NB rigid pipe (with a larger ID as compared to the risers) will be considered prior to FID and weighed up against the risks to pigging operations if a Dual Tieback to Karish Main is the selected concept.

With the size of flowline under consideration, the cross sectional area available to flow is 108 $inch^2$ as opposed to the single flowline options which are limited to 41 $inch^2$, reducing the minimum FWHP for any flowrate. The dual line also provides options to increase stable flow and arrival temperatures at low flow rates by shutting in one of the flowlines.

7.1.1.3.1 Concept B-1 Subsea Tieback by Dual Line to Karish Main Manifold- KN02 deviated well

This option installs a new two slot manifold close to KN01 and connects using 2 x 5.1km 10” NB (8” ID, as per the risers) flowlines to the pigging loop on the Karish Main Manifold. The design allows for all production from Karish North to be directed to an individual riser- this allows flexibility to flow Karish North at lower pressure than Karish Main in order to optimize production of Karish North gas and liquids.

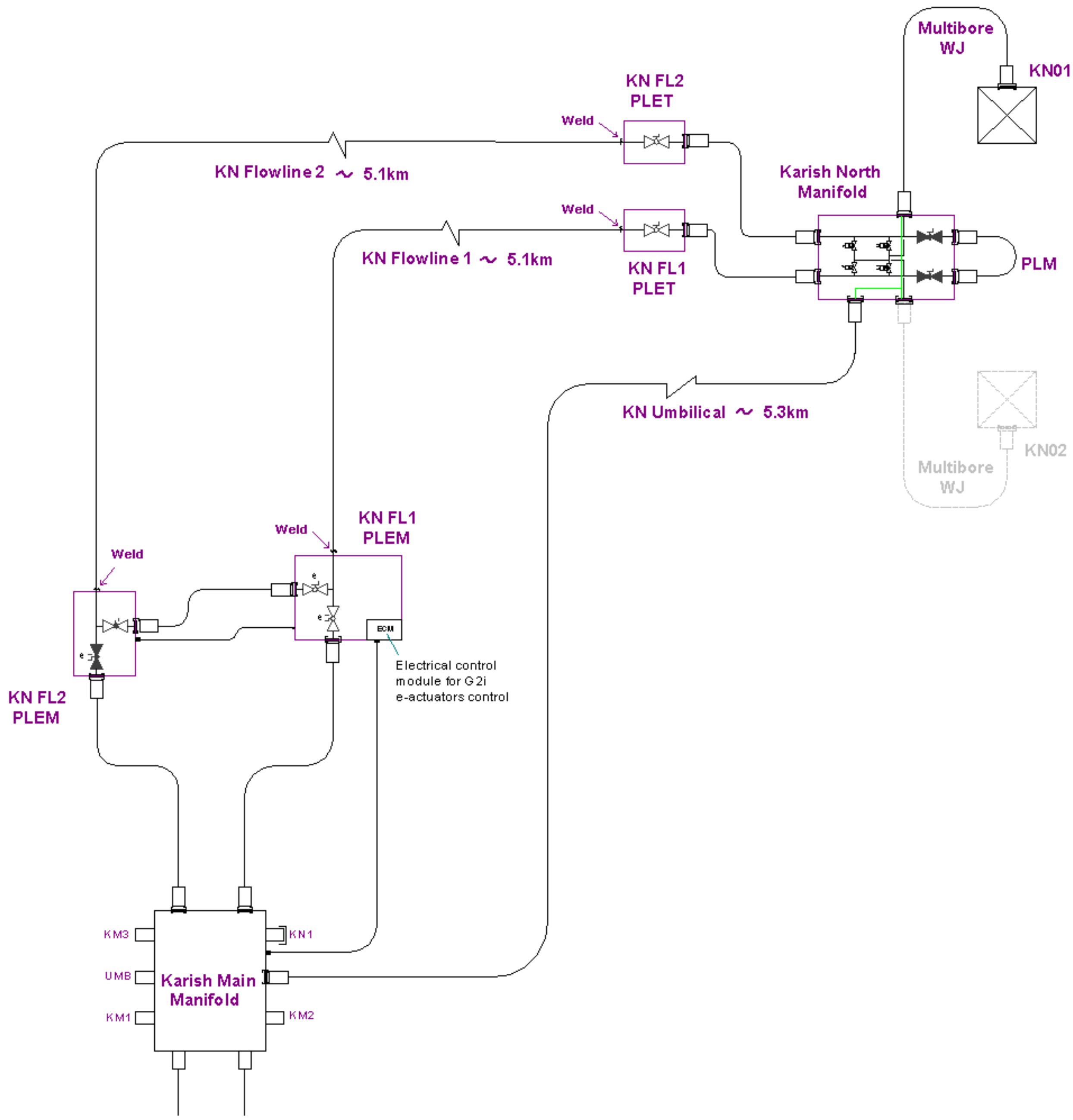


Figure 7-5 – Concept B-1 Schematic

Other features of this concept are that:

- Each flowline has its own PLEM and PLET that is installed inline with the rigid flowline
- The KN manifold is installed with a standalone lift
- The Pigging Loop from the Karish Main Manifold will be re-installed on the Karish North manifold to allow round-trip pigging of the carbon steel KM and KN flowlines
- Subsea pigging for pre-commissioning will be performed using 2 x subsea Pig Launcher/Receivers, unless a planned shutdown of the FPSO can be used to round trip pig the new flowlines to Karish North, or the service line may be used to flush the lines with N2
- The flowlines are currently a non standard 10” NB wall thickness to ensure no ID changes for round-trip pigging, costs could be reduced if small ID change were incurred

Advantages	Disadvantages
Dual Flowlines Increase Karish North Flow Capacity and Recovery	Larger scope and therefore larger costs than single line option
Provides flexibility of flowing on a single line to improve turndown	Increased inspection and maintenance costs
Can flow individual wells down different flowlines without incurring large temperature drop across well choke to balance production	If a second line is deferred, then round trip pigging may not be performed until after the second installation campaign
No major pre-investment required for KN02	Costs and risks of deviated drilling
Reduced intelligent pigging operations costs over single tieback	
KN02 location can vary until sanction of second well	
The second dual line could be deferred until capacity required	

Table 7-5 – Concept B-1 Advantages and Disadvantages

7.1.1.3.2 Concept B-2 Subsea Tieback by Dual Line to KM Manifold- KN02 vertical well

This concept only varies from Concept B-1 by the manner in which KN02 is tied into the manifold. If KN02 is a vertical well then it requires a ~1.1 km tieback to the Karish North Manifold. The design of this tieback is the same as that shown in Concept A-3, utilizing a flexible installed between two PLETs which connect to the multibore connections on the manifold and XT. The only difference is that instead of tying in at a PLEM located near KN01, it ties in at a manifold.

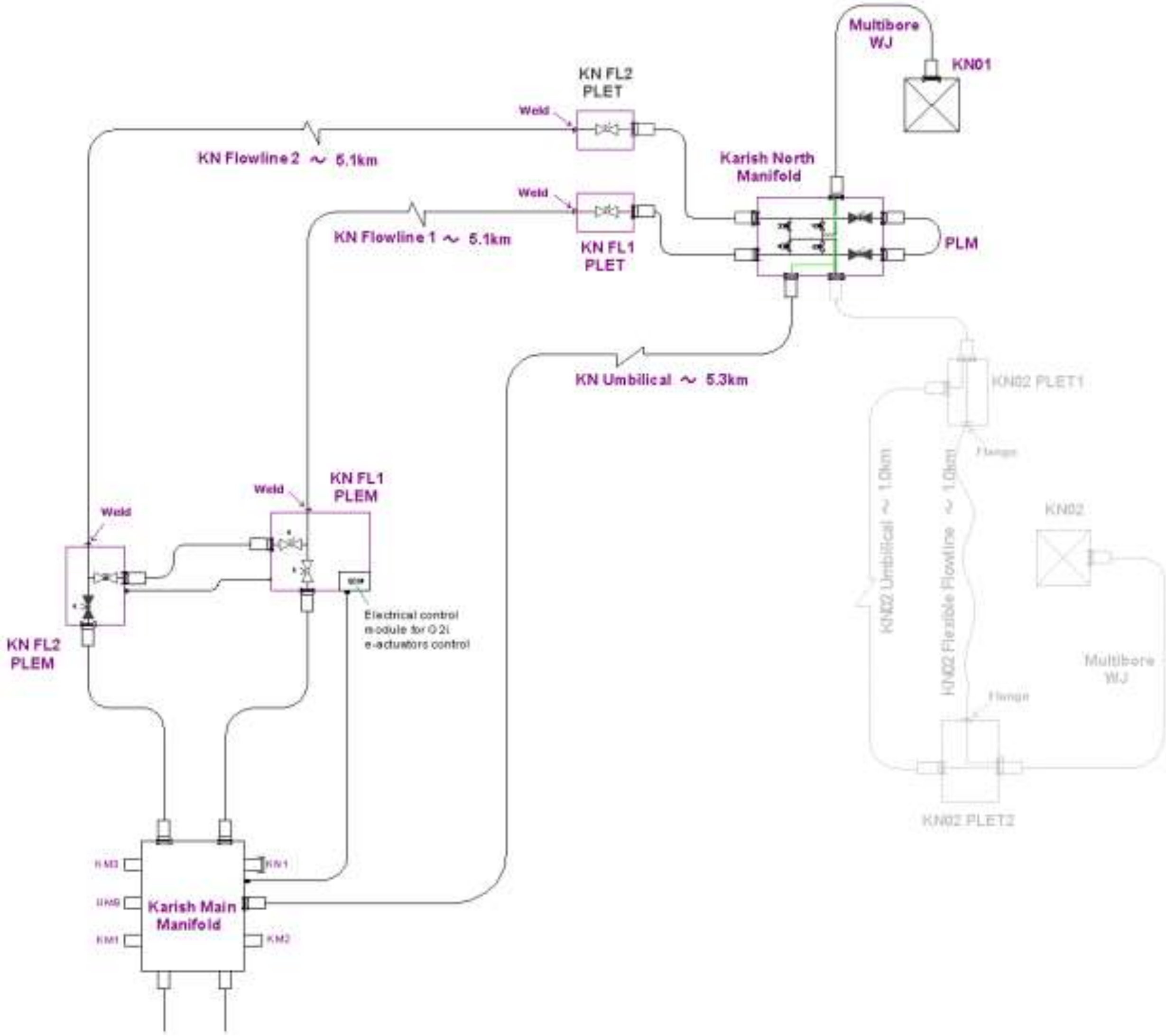


Figure 7-6 – Concept B-2 Schematic

Features of this concept are that:

- KN02 is drilled as a vertical well connected back to the Karish North Manifold by a ~1.1 km 7.19” ID flexible to reduce costs for the second installation campaign
- Costs also reduced for the KN02 installation campaign by pre-commissioning the KN02 flexible by using the well to flush the MEG/water through to the FPSO

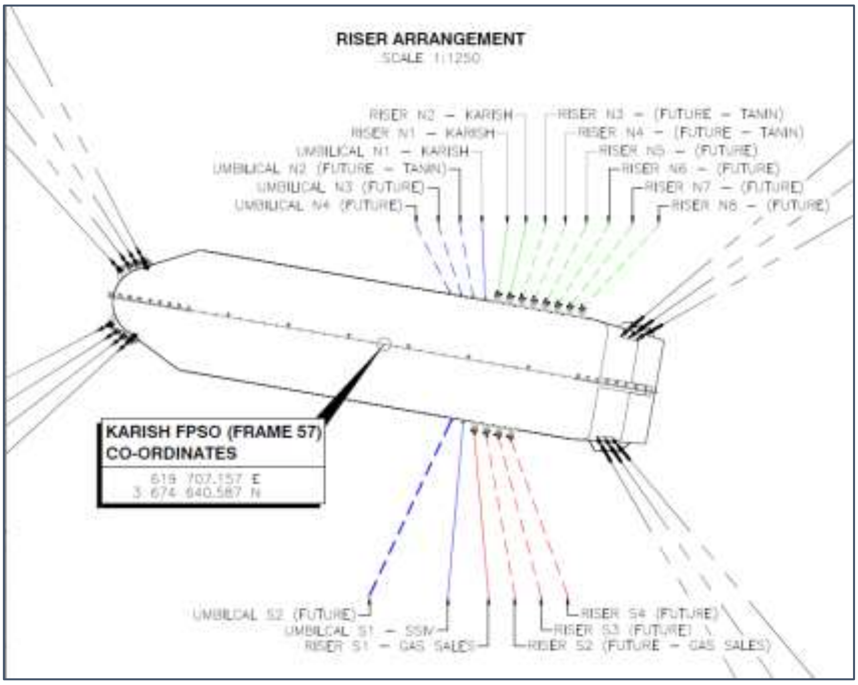
Advantages	Disadvantages
Dual Flowlines Increase Karish North Flow Capacity and Recovery	Larger scope and therefore larger costs than single line option
Provides flexibility of flowing on a single line to improve turndown	Increased inspection and maintenance costs
Can flow individual wells down different flowlines without incurring large temperature drop across well choke	Longer flow path and therefore pressure drop for KN02 fluids compared to deviated well
No major pre-investment required for KN02	Additional costs for KN02 tieback compared to a deviated well
Reduced intelligent pigging operations costs over single tieback	If a second line is deferred until capacity is available, then round trip pigging may not be performed
KN02 location can vary until sanction of second well	
The second dual line could be deferred until capacity required	

Table 7-6 - Concept B-2 Advantages and Disadvantages

7.1.1.4 Dual Tieback Direct to FPSO

The largest reduction in FWHP is observed if Karish North is tied back directly to the Energean Power FPSO. In this scenario, the flow area is 108 inch^2 from the wellhead to the FPSO if both risers are installed, reducing the pressure drop lost in the lines and the distance travelled by Karish North Fluids is reduced to 7.9km. However, it will obviously be significantly more expensive and utilize one or two of the six spare risers on the Energean Power FPSO.

Figure 7-7 – Energean Power FPSO Riser Locations



7.1.2 Flow Assurance and Hydrate Management

The Steady State Flow Assurance by TFMC shows that the FWHP are in line with those detailed in **Figure 6-4**. For arrival temperatures at the FPSO, TFMC investigated a worst case scenario, the Karish North Fluids flowed through a dedicated riser from the Karish Main Manifold to the FPSO, with no commingling with warmer Karish Main production, and KN02 drilled as a vertical well with a surface flowline of 1.1km tying it back to the Karish North manifold. They performed analysis for a range of conditions based on Eclipse simulations considering uncertainties such as the strength of the aquifer.

The anticipated arrival temperature in steady production under turndown conditions are above the highest Hydrate Formation Temperature of 29degC for the Karish North Fluids, although, cases with a weak aquifer arrive below 40degC towards the end of field life. Until full dynamic simulations are performed during FEED, 40degC is assessed to be the minimum arrival temperature which would allow sufficent No Touch Time (NTT) and time for depressurising the Karish North flowline to avoid hydrate formation.

Description		Simulation number	Reservoir pressure (bara)	Gas flow rate (MMscfd)			Condensate flow rate (bbl/d)		Water gas ratio (bbls/MMscf)		Upstream topsides choke	Ambient conditions	Pipeline			Well jumper		
				Well KN-1	Well KN-2	Total gas flow rate	Well KN-1	Well KN-2	Well KN-1	Well KN-2	Temperature (°C)		Size	U-value (W/m2K)	Roughness (mm)	ID (mm)	U-value (W/m2K)	Roughness (mm)
4 steady state load cases for KN-1 only	KN-1 only. Calculate if FPSO arrival pressure of 250 bara is met and calculate FPSO arrival temperature.	SS_A_1	Initial	200	0	200	4616	0	0	N/A	51	Winter	8" NB	3.7 (rigid)	0.046 (rigid)	6" NB (OD=168.3 mm, ID = 131.7 mm)	3.7 (rigid)	0.046 (rigid)
	KN-1 only. Calculate if FPSO arrival pressure of 250 bara is met and calculate FPSO arrival temperature.	SS_A_2	Near-initial	194	0	194	4559	0	0	N/A	47							
	KN-1 only. Calculate if FPSO arrival pressure of 210 bara is met and calculate FPSO arrival temperature.	SS_A_3	Abandonment	144	0	144	3413	0	47	N/A	49							
	KN-1 only. Calculate if FPSO arrival pressure of 250 bara is met and calculate FPSO arrival temperature.	SS_A_4	No aquifer end of plateau	200	0	200	4596	0	0	N/A	47							
4 steady state load cases for KN-1 and KN-2	KN-1 and KN-2. Calculate if FPSO arrival pressure of 250 bara is met and calculate FPSO arrival temperature.	SS_A_5	Initial	121.8	116.4	238.2	2780	2656	0.0	0.0	48	Winter	8" NB	3.7 (rigid)	0.046 (rigid)	6" NB (OD=168.3 mm, ID = 131.7 mm)	3.7 (rigid)	0.046 (rigid)
	KN-1 and KN-2. Calculate if FPSO arrival pressure of 250 bara is met and calculate FPSO arrival temperature.	SS_A_6	Near-initial	114.0	105.2	219.2	2651	2446	0.0	0.0	47							
	KN-1 and KN-2. Calculate if FPSO arrival pressure of 210 bara is met and calculate FPSO arrival temperature.	SS_A_7	Abandonment	88.7	116.0	204.7	2075	2715	44.7	0.0	46							
	KN-1 and KN-2. Calculate if FPSO arrival pressure of 250 bara is met and calculate FPSO arrival temperature.	SS_A_8	No aquifer end of plateau	41.4	30.4	71.8	820	602	0.0	0.0	34							
No Aquifer Sensitivities	KN-1 and KN-2. Calculate if FPSO arrival pressure of 250 bara is met and calculate FPSO arrival temperature.	SS_A_8a	No aquifer end of plateau	41.4	30.4	71.8	820	602	0.0	0.0	35	Winter	8" NB	3.2 (rigid)	0.046 (rigid)	6" NB (OD=168.3 mm, ID=131.7 mm)	3.7 (rigid)	0.046 (rigid)
	KN-1 and KN-2. Calculate if FPSO arrival pressure of 250 bara is met and calculate FPSO arrival temperature.	SS_A_8b	No aquifer end of plateau	50.0	50.0	100.0	990	990	0.0	0.0	39.5							

Table 7-7 – Steady State Flow Assurance Thermal Modelling Results for Concept A-3

Table 7-7 shows the results of the Steady State thermal modelling. As can be seen, the only case which does not result in arrival temperature of 40degC or above is case SS_A_8 which is based on a two-well Karish North development at abandonment with the reservoir poorly supported by an aquifer. As there is limited water influx in the field, the reservoir pressure declines further and yet the wells continue to flow, albeit at low rates, because they have not yet suffered water breakthrough, causing them to become liquid loaded. Therefore, from a thermal perspective, this is a very challenging case. TFMC evaluated two methods of ensuring a sufficient arrival temperature for this well. The first was to increase the wet insulation to provide a U value of 3.2 W/m^{2}K (case SS_A_8a) which only improved the arrival temperature to 35degC. The (case SS_A_8b) second continued to use this improved insulation, but also limited the minimum flowrates of the wells to 50 MMscf/d each which increased the arrival temperature to 39.5 degC which was deemed acceptable. Pipe in Pipe insulation was considered, however, given that the subsurface team view the weak aquifer case as highly unlikely in addition to it being possible to maintain the arrival temperature by increasing the minimum flow per well to 50 MMscf/d in a weak aquifer scenario, it was deemed that it would not be necessary to consider a development requiring the additional CAPEX and installation complexity of Pipe-in-Pipe.

Therefore, it was concluded that in normal flowing conditions, the wet insulation will be sufficient to prevent hydrates forming in the system, with depressurisation during extended shutdowns. However, as per the Karish Main operating philosophy, if the Flowline from Karish North to the Karish Main manifold is shut-in for a significant period with the Karish Main wells in production then it will be flushed with MEG. MEG is injected downstream of the Production Wing Valve (PWV) using a re-configured UCON Hub connector on the KN01 XT.

As highlighted above TFMC simply validated the internal steady state pressure modelling performed by Energean (see **Figure 6-4** which considers the three main tieback options). Further work was performed to support the exclusion of the Hybrid tie-back option where an 8" and 6" flowline are merged prior to the 4.9" ID well slot rather than tying in at the pigging loop (see **Figure 7-8**). As can be seen the benefits of moving to concept B-1 (dual tieback to KM Manifold) over A-2 (single tieback to KM04 well slot) are more than twice that of moving to the hybrid option of two lines tying in at slot KM04 regardless of the reservoir pressure.

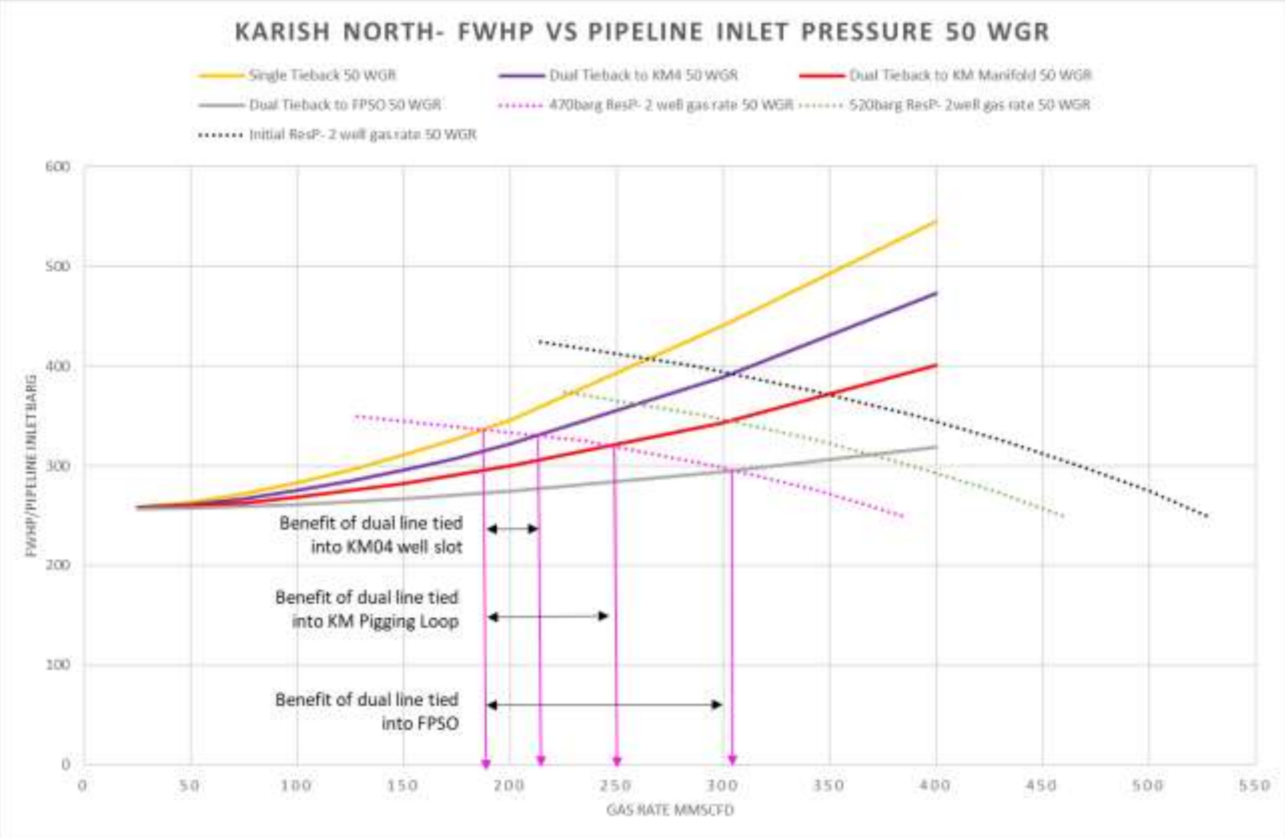


Figure 7-8 – Maximum Gas Rates for Two Karish North Wells for Different Development Options

7.1.3 Impact on Karish Main Development

The impact of Karish North on Karish Main can be divided into two main categories:

- Impact of Karish North development activities on Karish Main production
- Impact of Karish North production on operation of Karish Main and the Eneregan Power FPSO

The impact during construction will mainly relate to production outages, minimized wherever possible during installation and tie-in activities. For the reference case there is not expected to be any topsides modifications which will effect operations on the FPSO itself, however there will be increase marine activity during the well and subsea scopes of work.

During production, the main impact of Karish North is expected to be an increase in Karish Manifold pressure if Karish North production is commingled with Karish Main Production in the risers. If Karish North production flows through a dedicated riser it will constrain Karish Main to a maximum of 400 MMScfd. There is an unknown impact from the wax identified in the Karish North fluids, whilst still relatively low this is more likely to cause issues with the topsides processing rather than the subsea system. It is not anticipated that the Karish North development will require an increase in liquid handling capacity on the Energean Power FPSO compared to the original FDP.

7.2 Well Engineering

7.2.1 Overview

The Karish North wells will follow the general well designs proven from previous development wells on Karish Main and other exploration wells. This design has evolved as experience has been gained on these wells.

There are two wells planned. Karish North **KN01-ST04** is a sidetrack from the previous exploration and appraisal well. This utilizes the existing casing and wellhead, which was selected with a future development in mind. This well is currently suspended and will be sidetracked from the 13 5/8” casing to a well TD into the Karish North C sands.

The second development well, Karish North **KN02**, is planned from new well/wellhead. The location studies here is a well in the North East Crest, however, following initial well location optimization it is believed the well will be drilled in the East Crest, albeit with a similar step-out from KN01. Therefore, pending shallow hazards studies it is believed that the deviated well design presented here can be applied to any of the KN02 locations under investigation. Currently, there are two potential options being studied for this well:

1. **Vertical well:** A new vertical well will be drilled from a location on the seabed which is directly above the reservoir target.
2. **Deviated well:** A new well will be drilled from a location approximately 50 m NE of the existing KN01 wellhead seabed location. This will then be drilled deviated with a maximum inclination of +/- 52º inclination to the same target as proposed in the vertical option above.

The final decision on which option will be made based on an economic, environmental and risk assessment. Both options for KN02 are presented here.

Experience on previous wells in the area has shown that highly deviated wells may be difficult to drill with water based mud. The development wells on Karish Main were deviated up to 60 degrees inclination. Significant operational problems were experienced on these wells with stuck drilling BHAs and wireline logging tools. The root cause was a reactive and over-pressured (under-compacted) shale section below the salt down to the Mid-Miocene Unconformity. This section was prone to enlargement, and due to its fissile nature, cuttings and cavings became ground up and reacted with the water based mud to make hole cleaning and tripping problematic.

Well design changes have been incorporated to reduce the risk of similar problems on future wells including the Karish North development wells. All future wells will include the addition of an 11 ¾” drilling liner set just below the MMU to isolate the problematic shale formation. In addition, highly deviated wells should be drilled with oil based mud to permit safe tripping of the drilling BHA and wireline logging should be omitted from this section. Drilling vertically wells will also include the extra 11 ¾” drilling liner but there is less justification for using oil based mud, and water based mud can continue to be considered as a possibility. Another driver to use oil based mud is to achieve better core recovery. Whilst coring clean sandstone proved to be successful with water based mud, very poor recovery was observed when attempting to core clay rich interbedded formations e.g. B-sand.

All wells will be designed, drilled and completed in accordance to UK O&G standards. This philosophy has been used in all previous wells drilled and completed by Energean in Israel to date. All wells will be subject to verification via the UK Well Examination process, an independent design and operational integrity check prior to and during well construction.

7.2.2 Well Design

7.2.2.1 Well Design Objectives

The main objectives used to design the wells are:

- Compliance with applicable legislation in the UK and Israel
- No damage to the environment, equipment or personnel
- Assurance of well integrity whilst drilling and throughout the life of the field
- Conformance with company and contractor group management systems
- Drill and complete the Karish North development wells to deliver the development's estimated reserves within agreed budget and schedule
- Deliver all well reserves and production targets

7.2.2.2 Section Overview

All wells will follow the same general design principles as developed from previous experience and learning. The Karish North development well design comprises 5 casing strings:

36" Conductor – 6 conductor joints jetted to depth approximately 72m below seabed

Drill 24" hole, set 20"casing – This section will be drilled "riserless" in 24" hole with returns to the seabed. The casing shoe is set into the ME50 sub-unit of evaporite/salt section approximately 50m above the ME40 formation. This is to avoid drilling into a potentially over pressured brine section within ME40 sub-unit.

Drill 17½" hole, set 13⅝" casing – After connecting the riser/BOP's, this section will be drilled in 17½" hole and the casing shoe is set approximately 50m above the base of the massive salt formation. This is to ensure the casing shoe is set a competent formation to ensure a good cement job can be achieved.

Drill 12¼" x 14¾" hole, set 11¾" Liner – This section is drilled with a 12¼" bit and enlarged to 14¾" allowing sufficient clearance to run an 11¾" liner. The liner is hung off inside the 13⅝" casing and the liner shoe is set approximately 100m TVD below the MMU and 70m TVD above top A Sand. The purpose of this section is to isolate the unstable and the reactive clay formation. This will help secure coring and wireline data acquisition objectives in the next hole section.

Drill 8½" pilot hole – Required for KN02 to fully evaluate the structure at that location all the way down to the GWC. After data acquisition objectives have been met (core and wireline), the pilot hole will be plugged with cement all the way back to the 11¾" liner. No pilot hole is required for KN01 ST04

Drill 8½" x 12¼" hole, set 10¾" x 9⅝" liner – This section is drilled down to top reservoir with an 8½" bit and enlarged to 12¼". The 10¾" x 9⅝" production casing is then run, and the casing shoe set approximately 2-3m into the top of the target sand. This may be either in the B or C sand.

Drill 8½" x 9⅞" hole section to TD – The final section will be drilled within the reservoir with an 8½" bit and enlarged to 9⅞" hole to provided clearance for the lower completion.

Following drilling, the reservoir section will be completed with sand screens and gravel packed, refer to completion section.

7.2.2.3 Preliminary Well Locations and Targets

The following surface location and reservoir targets for both KN 01 ST04 and KN 02 are preliminary. The preliminary well designs have been based on these locations:

7.2.2.3.1 KN01-ST04 Seabed Location

Karish North KN01 - ST04 **(East Med; WGS84 Zone 36N)**	Geographical (WGS84)	Latitude	33° 15' 30.549 N
		Longitude	34° 20' 14.160 E
	Grid (WGS84, UTM Z36)	Easting	624 560.90 mE
		Northing	3 680 740.57 mN

Table 7-8 - Karish North KN01 Surface Location

7.2.2.3.2 Karish North KN02 Seabed Location (Vertical Option)

Karish North KN 02 **(East Med; WGS84 Zone 36N)**	Geographical (WGS84)	Latitude	33° 16' 1.500 N
		Longitude	34° 20' 32.763 E
	Grid (WGS84, UTM Z36)	Easting	625 030 mE
		Northing	3 681 700 mN

Table 7-9 – Karish North KN02 Seabed Location (Vertical Option)

7.2.2.3.3 Karish North KN02 Seabed Location (Deviated Option)

Karish North KN 02 **(East Med; WGS84 Zone 36N)**	Geographical (WGS84)	Latitude	33° 15' 31.684 N
		Longitude	34° 20' 15.534 E
	Grid (WGS84, UTM Z36)	Easting	624 596 mE
		Northing	3 680 776 mN

Table 7-10 – Karish North KN02 Seabed Location (Deviated Option)

7.2.2.3.4 Karish North KN01-ST04 Wellbore Target

Karish North KN 02 **(East Med; WGS84 Zone 36N)**	Geographical (WGS84)	Latitude	33° 15' 35.954 N
		Longitude	34° 20' 9.606 E
	Grid (WGS84, UTM Z36)	Easting	624440.93
		Northing	3680905.52
	Depth	TVD mBRT	4757.0

Table 7-11 – Karish North KN01-ST04 Target

7.2.2.3.5 Karish North KN02 Wellbore Target

Karish North KN 02 **(East Med; WGS84 Zone 36N)**	Geographical (WGS84)	Latitude	33° 16' 1.500 N
		Longitude	34° 20' 32.763 E
	Grid (WGS84, UTM Z36)	Easting	X 625 030 mE
		Northing	Y 3 681 700 mN
	Depth	TVD mBRT	4757.0

Table 7-12 – Karish North KN02 Target

7.2.2.4 Karish North KN01-ST04

7.2.2.4.1 Existing Status

The existing status of the KN01-ST03 well is presented below. This well currently is suspended with cement filling the entire open hole sections of all previous wellbores.

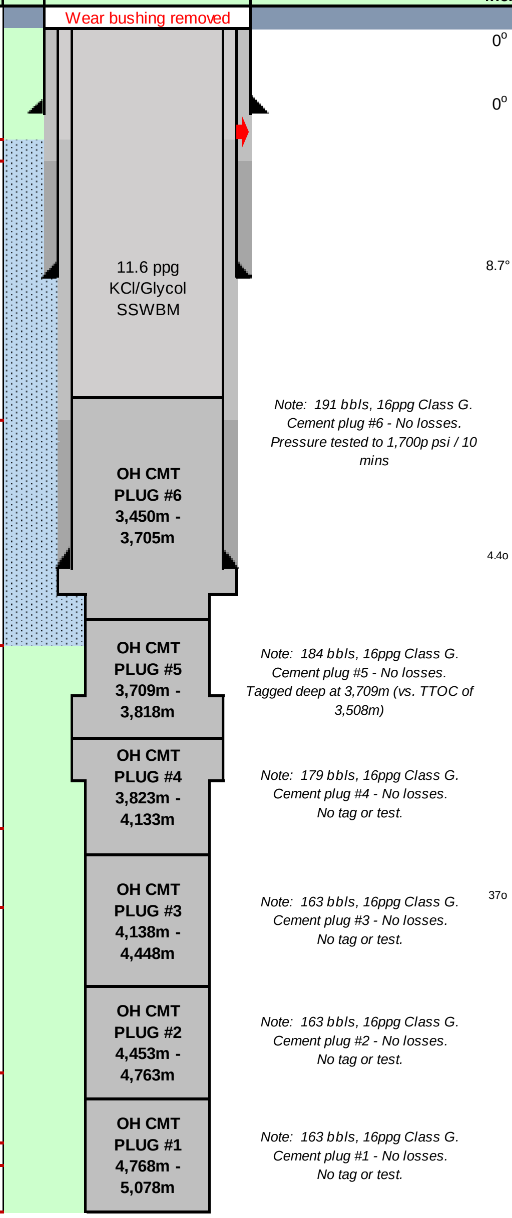
Karish North 01 ST03 (KN01 ST03) Well Schematic - SUSPENDED (06/11/19)

Rig	Stena DrillMAX	RTE (m)	31.6	Water Depth (m)	1,726

Casing / Liner Details

Size	Wgt (lbs)	Grade	Connection	Drift (in)	Cement Wt/Type Planned TOC	Mud Weight / Type	FIT / LOT (ppg)
36"	552.7	X-80	Leopard SD EF	31.265	Jetted	8.6 SW & Barazan hi-vis sweeps	N/A
	373.9	X-56	Leopard SD EF	31.265			
21" Ext. joint x 20"	21" 263.9	X-65	Swift DW2 HTAR	18.125	12.5ppg G Lead, 15.8 ppg G Tail, Surface	8.6 SW & Barazan hi-vis sweeps. 10.5ppg SSWBM from 2,735m	11.9
	20" 147.0	X-65		18.125			
13.5/8"	88.2	P-110	VAM 21	12.250	13.0 ppg G Lead, 15.8 ppg G Tail, 2749m MDBRT	11.5ppg SSWBM	12.5

Formation	MDBRT (m)	TVDBRT (m)
Seabed	1762	1762
Top Evaporite (Anhydrite)	2162.00	2162.00
Top Massive Salt (Halite)	2224.00	2192.00
ME20	3465.00	3425.80
Base Salt	3759.00	3719.10
Top Tortonian Sands	4082.50	4062.00
Base Tortonian Sands	4200.50	4161.00
Mid Miocene UC	4543.00	4434.00
A Sand	4685.00	4549.00
B Sand	4787.00	4635.00
C Sand	4919.00	4757.00



Inc.	Description	MDBRT (m)	TVDBRT (m)
	Protection cap installed / VX gasket removed		
0°	Top HPWHH	1,758.08	1,758.08
	Top LPWHH	1,759.00	1,759.00
0°	36" Shoe	1,832.95	1,832.95
	20" Burst Disc	1,880.38	1,880.38
8.7°	20" Shoe	2,784.30	2,711.60
	20" TD	2,789.00	2,716.20
4.4o	13.5/8" Shoe	3,651.10	3,642.90
	17.1/2" TD / Rat-hole	3,656.00	3,647.80
	Start of ramp	3,680.00	3,671.74
	KOP	3,702.00	3,693.72
	13.1/2" Underream Se	3,769.00	
	Top cement (12.1/4")	3,962.00	
	Top Ramp	3,984.00	3,970.91
	Kick off point	4,002.00	3,987.78
37o	End build / start tang	4,195.00	4,156.06
	End tang / start drop	4,700.00	4,562.00
	TD	5,083.00	4,917.95

Geological prognosis from Geological Operations ProgramKarish North Exploration WellKarish North 01 ST02v3.2

Figure 7-9 - Karish North KN01-ST03 Existing Well Status

7.2.2.4.2 Proposed Well Design Overview, KN01-ST04

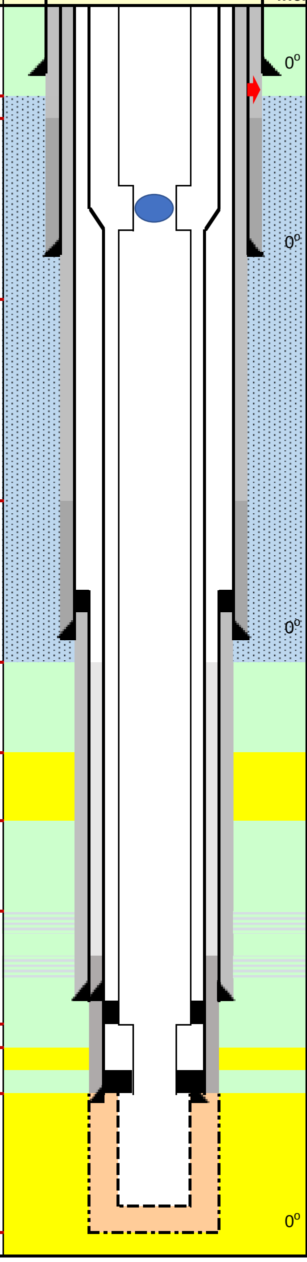
Karish North (KN 01 ST04) Well Conceptual Schematic

Rig	TBC	RTE (m)	31.6	Water Depth (m)	1,726

Casing / Liner Details

Size	Wgt (lbs)	Grade	Connection	Drift (in)	Cement Wt/Type	Mud Weight	FIT / LOT
36"	552.7	X-80	Leopard SD EF	31.265	Jetted	Seawater and sweeps	NA
	373.9	X-56	Leopard SD EF	31.265			
21" Ext. joint x 20"	21" 263.9	X-65	Swift DW2 HTAR	18.125	Class G/ Seabed	12.5ppg G Lead, 15.8 ppg G Tail, Surface	11.90 FIT
	20" 147.0	X-65		18.125			
13.5/8"	88.2	AISI 8630 Q125 P-110	VAM 21	12.250	13.0 ppg G Lead, 15.8 ppg G Tail, 2749m MDBRT	11.5 / Salt Sat. WBM	12.50 FIT

Formation	MDBRT (m)	TVDDBRT (m)
Seabed	1762	1762
Top Evaporite	2162	2162
Top Massive Salt	2224	2192
ME40	2895	2895
ME20	3465	3426
Base Salt	3759	3719
Top Tortonian Sands	4102	4062
Base Tortonian Sands	4201	4161
Mid Miocene UC	4474	4434
A Sand	4594	4549
B Sand	4680	4635
Upper C Sand	4807	4757
Well TD	4847	4797



Inc.	Description	MDBRT (m)	TVDBRT (m)
0°	36" Shoe	1833	1833
	20" Burst Disc	1880	1880
	5.1/2" TRSCSSV		
	10.3/4" x 9.5/8" crossover	2562	2562
0°	20" Shoe	2784	2712
	7" 32ppf P110 Tubing		
0°	13.5/8" Shoe	3651	3643
	KN 01 ST04 KOP	3702	3694
	Top of Cement 9 5/8"		
	11 3/4" Liner Shoe	4524	4479
	Production Packer		
	9 5/8" Casing Shoe	4809	4759
	8.1/2" x 9 7/8" Open Hole OHGP + premium screens		
0°	Well TD	4847	4797

Figure 7-10 - Karish North KN 01 ST04 Proposed Well Design

7.2.2.4.3 Well Directional Plan, KN01-ST04

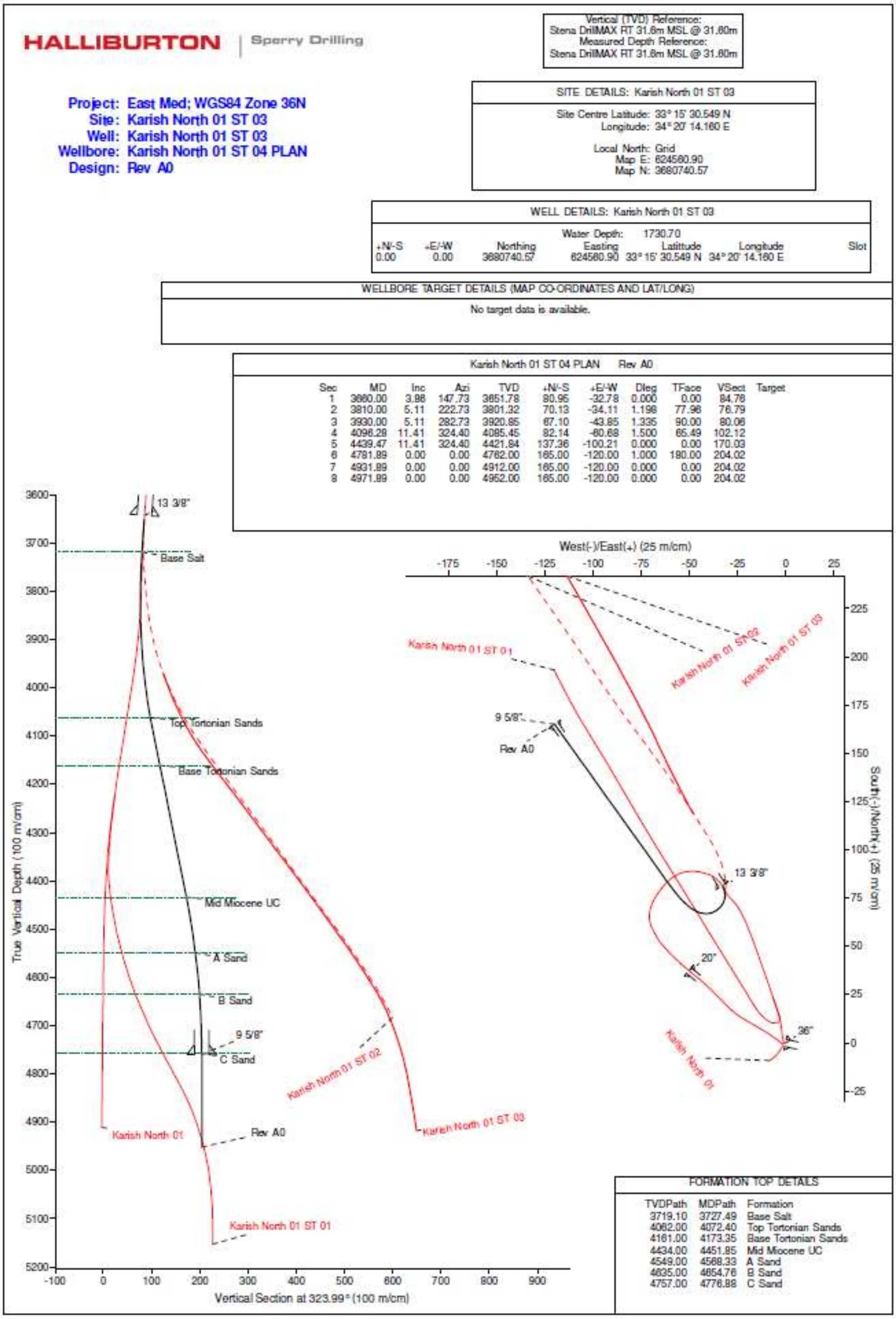


Figure 7-11 - Karish North KN01-ST04 Well Directional Plan

7.2.2.5 Proposed Well Design, KN02 (Vertical Well Option)

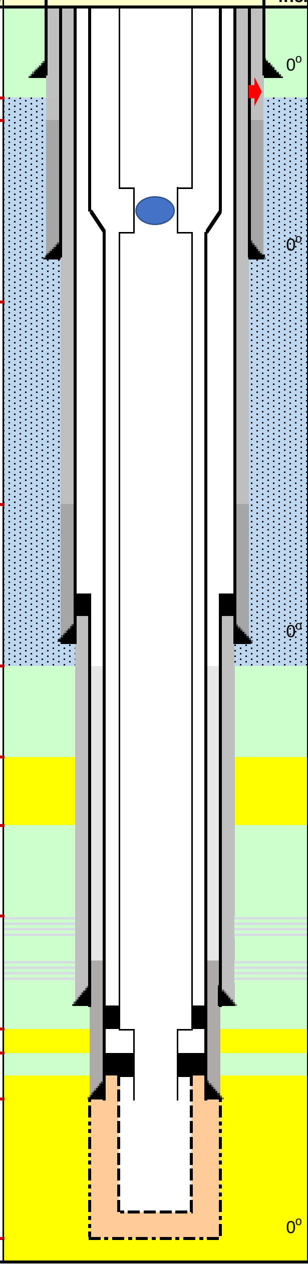
7.2.2.5.1 Proposed Well Design Overview, KN02 (Vertical Well Option)

Karish North KN 02 (Vertical) Well Conceptual Schematic

Rig	TBC	RTE (m)	31.6	Water Depth (m)	1,726

Casing / Liner Details

Size	Wgt (lbs)	Grade	Connection	Drift (in)	Cement Wt/Type	Mud Weight	FIT / LOT
36"	552.7	X-80	Leopard SD EF	31.265	NA	Seawater and sweeps	NA
	373.9	X-56	Leopard SD EF	31.265			
21" Ext. joint x 20"	21" 263.9	X-65	Swift DW2 HTAR	18.125	Class G/ Seabed	12.5ppg G Lead, 15.8 ppg G Tail, Surface	11.90 FIT
	20" 147.0	X-65		18.125			
13.5/8"	88.2	AISI 8630 / Q125 / P-110	VAM 21	12.250	13.0 ppg G Lead, 15.8 ppg G Tail, 2749m MDBRT	11.5 / Salt Sat. WBM	12.50 FIT



Formation	MDBRT (m)	TVDDBRT (m)	Inc.	Description	MDBRT (m)	TVDBRT (m)
Seabed	1762	1762				
			0°	36" Shoe	1834	1834
Top Evaporite	2162	2162		20" Burst Disc	1884	1884
Top Massive Salt	2192	2192				
				5.1/2" TRSCSSV		
				10.3/4" x 9.5/8" crossover	2562	2562
			0°	20" Shoe	2845	2845
ME40	2895	2895				
				7" 32ppf P110 Tubing		
ME20	3465	3465				
				11 3/4" Liner Hanger	3519	3519
			0°	13.5/8" Shoe	3669	3669
Base Salt	3719	3719				
				Top of Cement 9 5/8"	3912	3912
Top Tortonian Sands	4062	4062				
Base Tortonian Sands	4161	4161				
Mid Miocene UC	4434	4434				
				11 3/4" Liner Shoe	4479	4479
A Sand	4549	4549		Production Packer		
B Sand	4635	4635				
				Liner Hanger Packer		
Upper C Sand	4757	4757				
				9 5/8" Casing Shoe	4759	4759
				8.1/2" x 9 7/8" Open Hole OHGP + premium screens		
Well TD	4797	4797	0°	Well TD	4797	4797

Figure 7-12 - Karish North KN02 Proposed Well Design (Vertical Option)

7.2.2.5.2 Well Directional Plan, KN02 (Vertical Well Option)

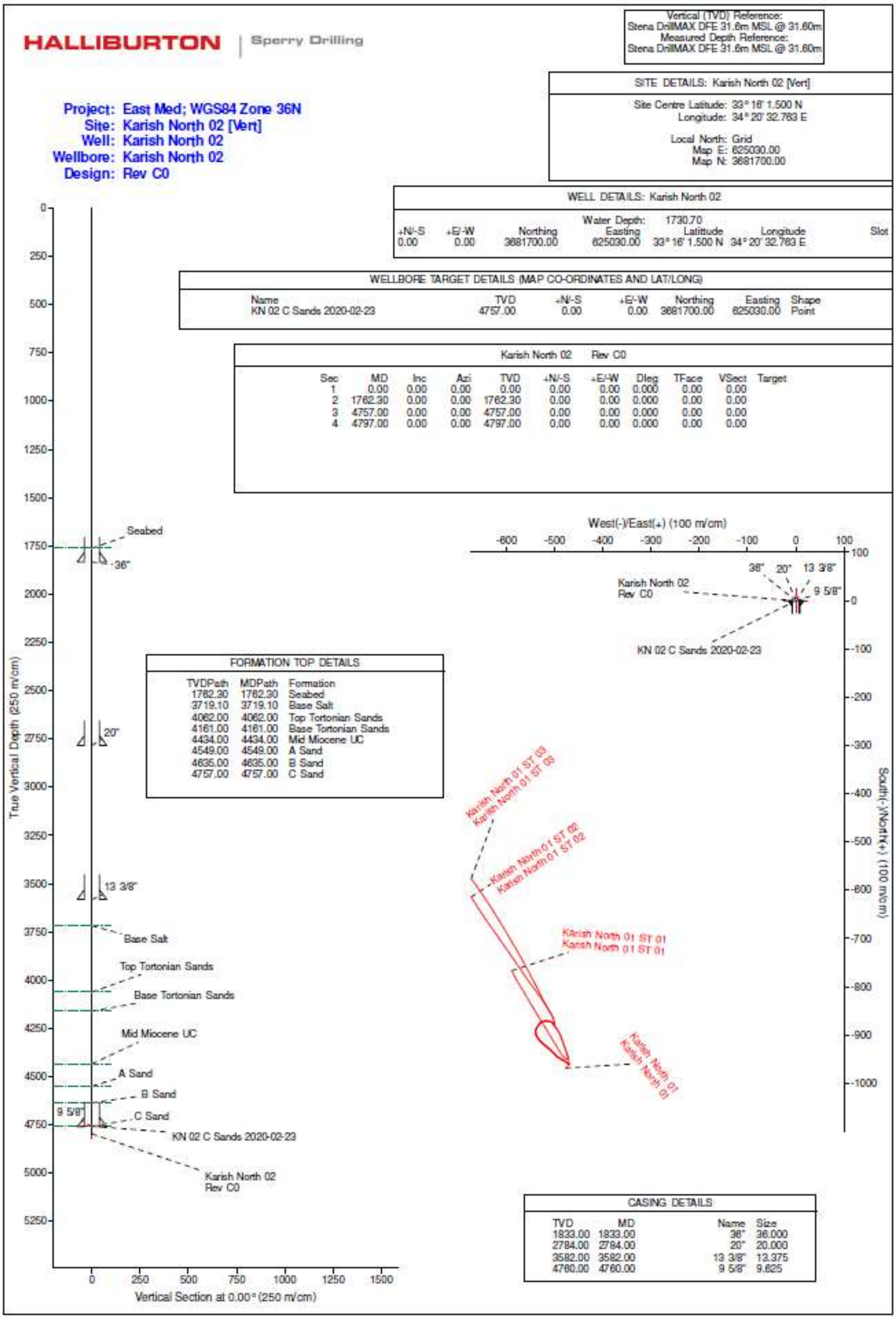


Figure 7-13 - Karish North KN02 Well Directional Plan (Vertical Well Option)

7.2.2.6 Proposed Well Design, KN02 (Deviated Well Option)

7.2.2.6.1 Proposed Well Design Overview, KN02 (Deviated Well Option)

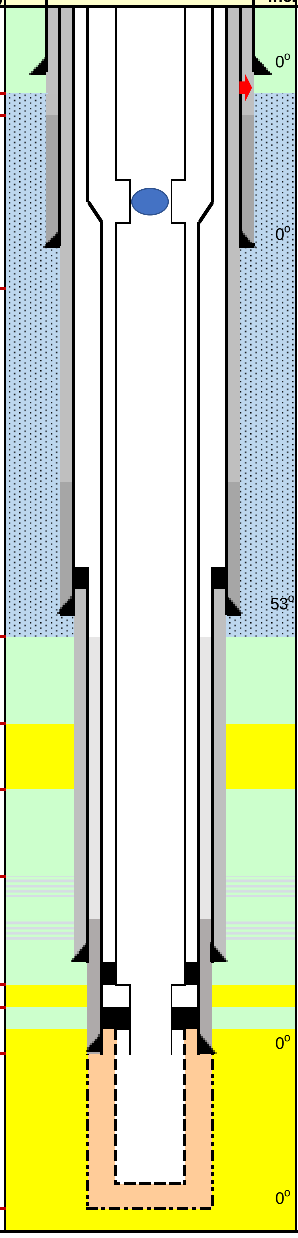
Karish North KN 02 (Deviated) Well Conceptual Schematic - NOT TO SCALE

Rig	Stena DrillMAX	RTE (m)	31.6	Water Depth (m)	1,726

Casing / Liner Details

Size	Wgt (lbs)	Grade	Connection	Drift (in)	Cement Wt/Type	Mud Weight	FIT / LOT
36"	552.7	X-80	Leopard SD EF	31.265	NA	Seawater and sweeps	NA
	373.9	X-56	Leopard SD EF	31.265			
21" Ext. joint x 20"	21" 263.9	X-65	Swift DW2 HTAR	18.125	Class G/ Seabed	12.5ppg G Lead, 15.8 ppg G Tail, Surface	11.90 FIT
	20" 147.0	X-65		18.125			
13.5/8"	88.2	AISI 8630	VAM 21	12.250	13.0 ppg G Lead, 15.8 ppg G Tail, 2749m MDBRT	11.5 / Salt Sat. WBM	12.50 FIT
		Q125					
		P-110					

Formation	MDBRT (m)	TVDDBRT (m)
Seabed	1762	1762
Top Evaporite	2162	2162
Top Massive Salt	2192	2192
ME40	2895	2895
Base Salt	3850	3719
Top Tortonian Sands	4358	4062
Base Tortonian Sands	4477	4161
Mid Miocene UC	4773	4434
A Sand	4891	4549
B Sand	4978	4635
Upper C Sand	5100	4757
Well TD	5140	4797



Inc.	Description	MDBRT (m)	TVDBRT (m)
0°	36" Shoe	1834	1834
	20" Burst Disc	1884	1884
	5.1/2" TRSCSSV		
	10.3/4" x 9.5/8" crossover	2562	2562
0°	20" Shoe	2845	2845
	7" 32ppf P110 Tubing		
	11 3/4" Liner Hanger	3552	3483
53°	13.5/8" Shoe	3652	3582
	Top of Cement 9 5/8"	4208	
	11 3/4" Liner Shoe	4821	
	Production Packer		
	Liner Hanger Packer		
0°	9 5/8" Casing Shoe	5103	4760
	8.1/2" x 9 7/8" Open Hole OHGP + premium screens		
0°	Well TD	5140	4797

Figure 7-14 - Karish North KN02 Proposed Well Design (Deviated Option)

7.2.2.6.2 Well Directional Plan, KN02 (Deviated Well Option)

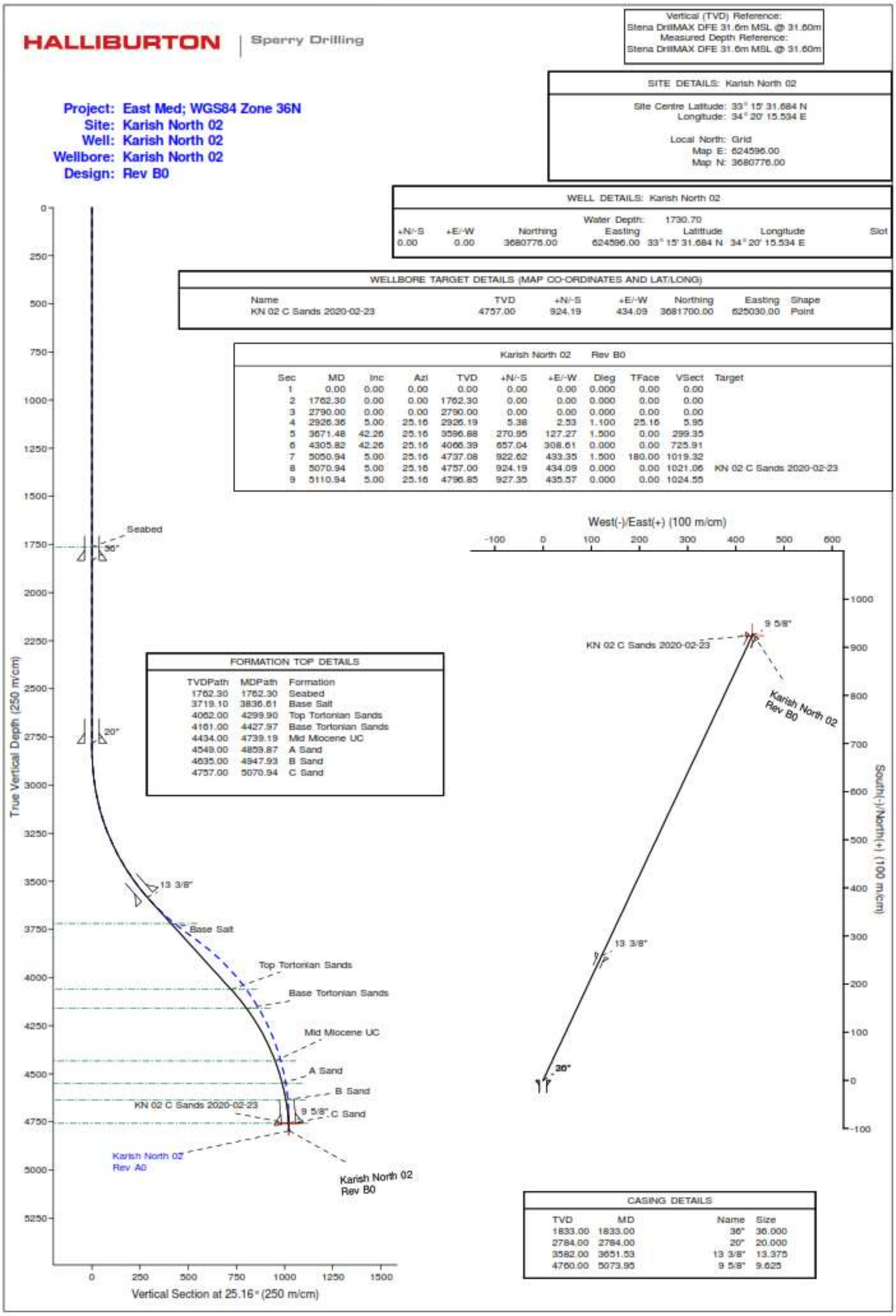


Figure 7-15 - Karish North KN02 Well Directional Plan (Deviated Well Option)

7.2.2.7 Drilling Unit

The final rig selection will be based on the requirements to drill and complete any wells included in the planned campaign. This will include the Karish North wells plus any other exploration/appraisal wells included on the schedule. Whilst a final decision on rig selection is still to be made, it is likely to be an advanced drillship similar to the Stena DrillMAX or used on the recent Karish and exploration wells (2019/2020). An overview of the Stena DrillMAX is included below in **Figure 7-16**.

Figure 7-16 – Stena DrillMAX Overwiew

7.2.3 Completion Design

The Karish Main (KM) completion design is the base case for the evaluation of options available to complete the B and C sands of the Karish North development. The KM sand face completion design consists of placing the 9⅝" production casing 2m inside the Upper C Sand and completing a 9⅞" under-reamed 35m open hole section with a circulating water open hole gravel pack.

Key features of the completion

- Designed to deliver 300MMscfd and a CGR range between 12-25bbls/MMscfd with planned production rates of 150-200MMscfd but allowing peak production at the design rate
- Monitoring of downhole pressure to allow real time reservoir surveillance and management
- Ability to inject chemicals downhole to manage the potential for future scale formation and hydrate formation
- B Sand is placed behind the 9⅝" casing and can be re-completed with the suspension of the C Sand and subsequent cased hole gravel pack across the zone
- TRSCSSV placed below the hydrate formation depth

Lower completion consists of the following components;

- 9⅝" x 6" packer including a gravel pack port and extension
- Formation isolation valve to allow suspension
- RA marker sub for future correlation
- 6⅝" 175µ premium mesh screens to 5m inside the production casing

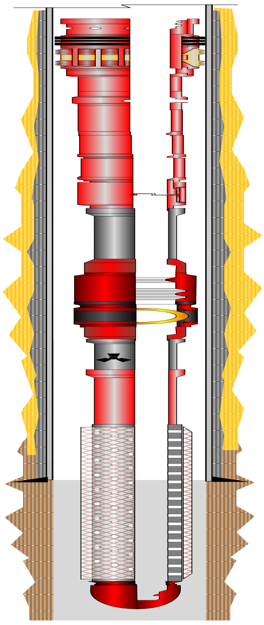


Figure 7-17 – Karish Main Lower Completion Schematic

Upper completion consists of the following components;

- 7" 32ppf 13Cr-95ksi Vam 21 tubing
- 5½" TRSCSSV place below the hydrate formation depth
- 5½" downhole gauge
- 5½" chemical injection valve
- 9⅝" x 7" upper completion packer
- Mechanical interface with the lower completion

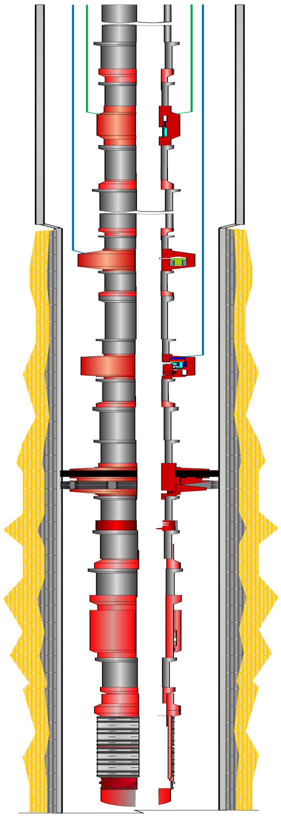


Figure 7-18 - Karish Main Upper Completion Schematic

To effectively develop Karish North the following variations to the design parameters utilized for KM provide the basis for the variation options under consideration:

- Completion delivery above 200MMscfd
- B Sand is high quality but also high heterogeneity, possibly connected to a different aquifer
- Upper C sand is high quality with NTG ~ 90%
- Lower C sand is still a good quality sand, however the NTG is ~ 25% and it has a lightly lower porosity but higher CGR than the Upper C
- Lower C sand closer to the GWC
- Optimising the Condensate to Gas Ratio of the produced fluids by accelerating production from deeper, more condensate rich zones, before reservoir pressure declines below the dewpoint:
  - B Sand - 8.9bbl/MMscfd in wellbore, 13.9 bbls/mmscf liquid yield after processing
  - Upper and lower C Sand – up to 76 bbls/mmscf in wellbore with ~100bbl/MMscfd after processing of the gas
- It would be optimal if the B Sands could be developed simultaneously with the C sands, i.e. a workover is not required to produce these sands
- Control water production; it is expected that the deeper sands, e.g. the Lower C Sands are the first to see water production, however, for completion concepts that develop the B sands simultaneously, there is a risk that the B sand GWC is higher than that observed in the C-sands, and so water production would be accelerated from these sands as compared to the C sands

7.2.3.1 Completion Concepts Under Consideration

7.2.3.1.1 Initial Screening

For the initial screening of completion options for the Karish North development based on addressing four main factors:

1) provide ability to produce at >200MMscfd for majority of field life,

2) design maximizes recovery,
3) B sand has high heterogeneity compared with Upper C and possibly in a different pressure compartment.
4) Lower C sand has richer gas than Upper C sand but is lower permeability.
5) Overall the gas contained in the Karish North accumulation has a higher CGR than that in Karish Main, therefore the design must account for a higher proportion of free liquid in tubing during production

Based on these factors, eight primary completion options were identified including the Karish Main base case and have been summarized below.

Completion Design Option	Comments on Suitability / Risks
Karish Main Design OHGP 35m into Upper C Sand	• Proven design – simplest to install and operate. • Allows highly productive Upper C sand to produce with large offset to the GWC. • Workover required to access B sand behind casing with CHGP.
OHGP across B & C Sand	• Possibility of early water breakthrough in B sand that would impact production from C sand if zones are not connected. • Possibility of cross flow between zones if they are not connected to same aquifer. • Gravel pack across large sections of shale that will be exposed during life of well, which could result in failure
OHGP across B & C Sand -ability to isolate the B & C Sand	• Only the lower zone can be isolated. • B sand water production cannot be isolated. • B sands connectivity unclear, potential for early water breakthrough • Open hole packer required. • Screen size reduction required to accommodate alternate path screens required – increased GP complexity. • Light well intervention required to install plug to isolate the C Sand.
OHGP across Upper and Lower C Sand	• Allows some acceleration of liquids production. • Risk of earlier water production as wellbore closer to GWC. • Workover required to access B sand behind casing with CHGP.
OHGP across Upper and Lower C Sand -ability to isolation upper and lower C sands	• Only the lower C sand can be isolated • Allows some acceleration of liquids production • Shale barriers between upper and lower C sands required to obtain isolation between zones with open hole packer (no such shale barriers are interpreted in Karish North) • Screen size reduction required to accommodate alternate path screens required – increased GP complexity • Workover required to access B sand behind casing with CHGP • Light well intervention required to install plug to isolate the C sand
SMART Well	• Lower C sand can be isolated once water breakthrough occurs • Ability to preferentially produce lower C to accelerate liquids production

OHGP across Upper and Lower C Sand	• Shale barriers between upper and lower C sands required to obtain isolation between zones with open hole packer • Screen size reduction required to accommodate alternate path screens required – increased GP complexity • Increased pressure drop through completion reduces well performance • Differential pressure across ICVs at onset of water production likely to cause significant salt/scale deposition • Workover required to access B sand behind casing with CHGP • Increased completion installation complexity • Limited completion track record in high rate gas wells
SMART Well OHGP across B Sand and Upper C Sand	• Increased pressure drop through completion reduces well performance • Ability to produce B and C sand independently • Ability to produce B sand without need for workover • Differential pressure across ICVs at onset of water production likely to cause significant salt/scale deposition • Increased completion installation complexity • Limited completion track record in high rate gas wells
SMART Well CHGP across B Sand and OHGP across Upper and Lower C Sand	• Increased pressure drop through completion reduces well performance • Significantly increased completion complexity Differential pressure across ICVs at onset of water production likely to cause significant salt/scale deposition • Allows B sand to be produced independently of C sand • Limited completion track record in high rate gas wells

Note: SMART Well is a *remotely operated selective completion*

From a purely risk perspective the following concepts have been screened out:

- OHGP across B & C sands (with and without ability to isolate the C sands): based on risk of early water production if there is a pressure disconnect between B and C sands leading to early depletion of B and early water breakthrough/crossflow as well as this design requiring large sections of shale exposed which may impair well productivity over time
- SMART Well across Upper and Lower C sands: based on lack of isolating shale barrier between Upper and Lower C sands which would negate the SMART well technology's ability to isolate production from different layers.
- SMART well producing through CHGP across B sands and OHGP across Upper C sands: this option has no advantages, and significant disadvantages, compared to an OHGP across the B Sands.

7.2.3.1.2 Concept Definition

A review of the initially screened completion options identified three to take forward to concept select phase of the design process:

1) KM Design OHGP across the Upper C Sand, with a B Sand Workover Option (both 7" and 5.5" tubing).
2) OHGP across the Upper and Lower C Sand with TD at 50m above GWC (workover for B Sand production), and
3) SMART Well OHGP across the B and Upper C Sand.

7.2.3.1.2.1 Karish Main OHGP Design

As discussed in Section 7.2.3.1 Consideration must be given to running a smaller tubing size to deal with the increased liquid yield in the gas to ensure stable flowing conditions.

7.2.3.1.2.2 OHGP Across Upper and Lower C Sand

The design base fundamentals follow those of the KM Base Case with the following variations;

- Consideration must be given to alternate path screens to ensure no impact on gravel pack due to shale instability
- TD to be 50m above GWC to manage water encroachment (which at KN01 would mean the completion is across 20m of the Lower C Sands)
- 9 7/8" under-reamed open hole
- Upper completion in line with KM Base Case,

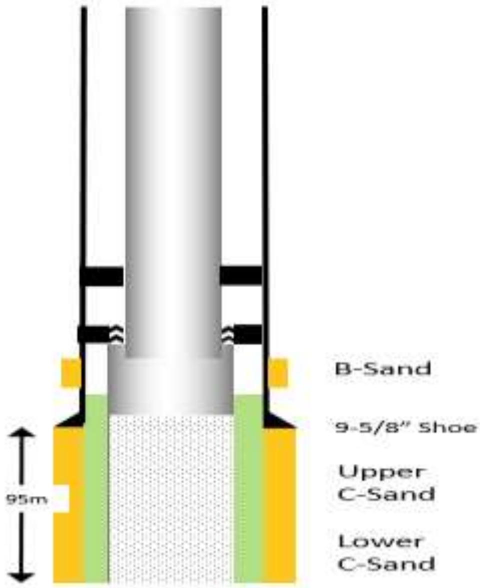


Figure 7-19 - OHGP over Upper and Lower C Sand

To produce the B sand in this completion design requires a workover that entails the following steps to implement.

- Install plug in the lower completion
- Wireline intervention to cut to release upper completion packer
- Recover upper completion
- Wireline intervention to cut above screens
- Recover upper section of lower completion
- Perforate across the B sand interval
- Run lower completion and conduct Cased Hole Gravel Pack (CHGP)
- Run upper completion

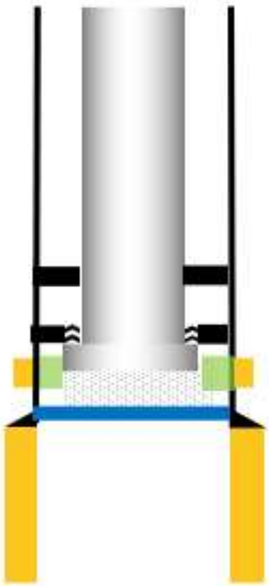


Figure 7-20 - Workover with CHGP over B Sand

7.2.3.1.2.3 SMART Well Completion to Produce the B and Upper C Sands Selectively

Well completion is designed to selectively produce the B and C sands through an OHGP covering both intervals with the well TD 40m into the upper C sand and flow controlled with hydraulically actuated flow control valves. SMART well completions consist of three sections:

1) Lower completion with OH packer and alternate path screens,
2) Intermediate completion with annular flow control devices, and
3) Upper completion with selective flow control valves.

The following features are required,

- Lower completion including;
  - Packer
  - Gravel pack extension
  - Fluid loss device – mechanical
  - Alternate Path screens with integral seal bore
  - Open hole mechanical packer
- Intermediate completion including;
  - 9 5/8” Packer
  - Dual flow bypass device with internal seal bore
  - Lower zone isolation device
- Upper completion including;
  - Flow Control Valves (ICVs) enabling
    - Isolation of bottom zone while flowing the upper zone
    - Isolation of upper zone while flowing the lower zone
    - Comingled flow of both upper and lower zones
  - 9 5/8” Packer
  - Cut sub for completion recovery/workover
  - Tubing and annulus Interval Control Valves (ICV)
  - Chemical injection sub
  - Pressure monitoring in both upper and lower zones
  - TRSCSSV positioned below the hydrate formation depth
- XT/tubing hanger configuration requirement to accommodate Qty-6 control lines and Qty-1 electrical penetrations to operate
  - TRSCSSV (dual 1/4” flatpack)

- DHG/Chemical Injection Line (dual 3/8" x Coaxial line flatpack)
- ICV Control line (Triple ¼" flatpack)

The flow path for the well fluids through the completion is detailed in below figure

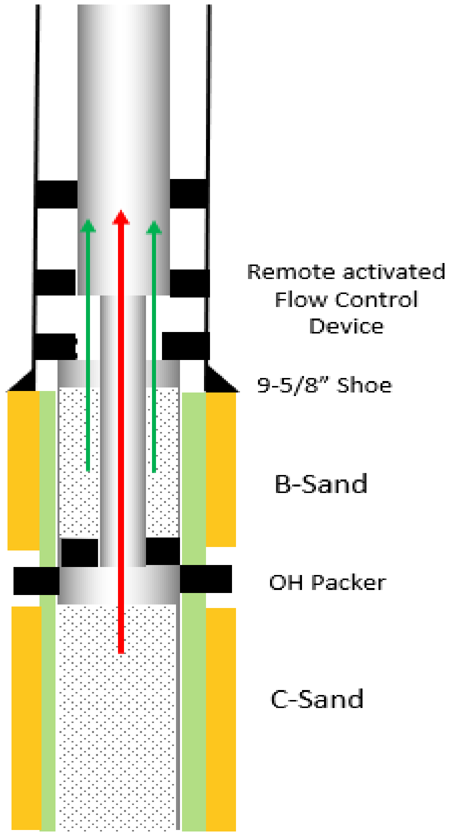


Figure 7-21 - SMART Well Production Flow Path

To achieve selectivity in the completion there are several in-built constraints that impact well productivity.

Lower Completion

- Maximum screen size is 5 ½" due to the requirement to utilize alternate path screens to allow zonal isolation and enable gravel packing of the both zones.
- Hole size is restricted to 9 ½" due to current open hole packer expansion capability

Intermediate Completion

- Lower zone through 4" tubing from the Openhole packer sealbore to the Twin-Flow – 3.46in ID (9.48in²)
- Upper zone through screen ID and 4" inner string OD – 5.36in² (equivalent ID = 2.62")
- Twin-Flow flow area
  - Upper zone flow – 6.56 in² over 3m
  - Lower zone flow – 7.55in² over 3m
- Combined flow area with lower zone and upper zone excluding restrictions through the Twin-Flow and ICVs is 14.84in² vs. 5 ½" tubing is 17.93in²

Upper Completion

- ICVs
  - 4 ½" ICV for upper zone – 11.04in²
  - 3 ½" ICV for lower zone – 5.940in²

- 5 ½" tubing string (17.93in²) vs. 7" tubing string (29.17in²)

Case histories are limited as there have been very little applications of SMART well technology in high rate gas wells due to the flow constraints and the identified risks

- Completion flow restriction restricting well performance
- Potential erosion through flow restrictions
- Scale/salt deposition across ICVs
- Installation complexity
- Significantly higher cost of completion

7.2.3.1.3 Comparison of Concept Costs, Performance and Risks

7.2.3.1.3.1 Completion Concept Costs

A comparison of the costs of equipment and installation has been prepared on a like for like basis accuracy of +20/-10%, see **Table 7-13** and **Table 7-14**. This comparison shows that the installed cost of the KM Base Case completion concept and the OHGP extending across the B & C sands are predicted to be very close, whereas the SMART well is predicted to cost approximately 30% more (excluding rig time).

Table 7-13 - Comparison of Completion Equipment Costs for Different Concepts

	KM Base Case	OHGP across B & C Sands	SMART Well (B & C Sands)
Equipment			
Lower Comp. Equip	0.850	1.100	1.100
Upper Comp. Equip	2.622	2.622	6.550
Tubulars	1,050	1,050	1,050
Total	**$4.522**	**$4.772**	**$8.700**

Note: All costs in MM USD and include back-up completion components

Table 7-14 - Comparison of Completion Installation Service Costs for Different Concepts

	KM Base Case	OHGP across B & C Sands	SMART Well (B & C Sands)
Services			
Wellbore Cleanup	0.750	0.750	0.750
Lower Comp. Installation	0.985	0.985	0.985
Gravel Pack Services	1.595	1.595	1.900
Filtration	0.532	0.532	0.532
Completion Fluids	0.975	0.975	0.975
Upper Comp. Installation	0.785	0.785	0.900
Well Clean-up	2,500	2,500	2,500

Comp. Landing String	3.260	3.260	3.260
Total	**11.382**	**11.382**	**11.802**

Note : All costs in MM USD

7.2.3.1.3.2 Installation Risks

The installation risks for the various options are summarized in **Table 7-15** below. As would be expected, the SMART well completion has a higher degree of risk during both installation and operation.

Table 7-15 – Installation and Operability Risks of Different Completion Concepts

Installation/ Operability Risks	Karish Main Base Case	OHGP across B and C Sand	SMART Well completion
Lower Completion	a) Low installation risk b) Conventional circulating water OHGP	a) Increased installation complexity b) Shale instability requires use of alternate path screens c) Gel system to place gravel across the open hole	a) Increased installation complexity b) Shale instability requires use of alternate path screens c) Gel system required to place gravel across the open hole d) Open hole packer activation
Upper Completion	a) Low installation risk b) Low operability risk	a) Low installation risk b) Low operability risk	a) Significantly increased installation complexity b) Flow performance restricted in comparison to other two options c) Increased operability risk- higher rate of failure

7.2.4 Reference Case Well Design Concept

Considering the costs, risks and performance of the various well and completion concepts discussed in sections 7.2.3.1.3.1, 7.2.3.1.3.2 and 6.7 the recommended reference case well design concepts are:

- KN01-ST04: as a development sidetrack of the KN01 well kicked off from 13 5/8" shoe using OBM and extra casing string to maximize chance of recovering B sand core. Well will be completed using the existing KM design developing C sands initially with a workover in late life to produce the B sands through a cased hole gravel pack.
- KN02: drilled as a deviated well from beside KN01 wellhead to the target with a step-out of ~1.1km, incorporating an additional casing string and the use of oil based mud below the salt based on learnings from the Karish Main development drilling. Completion based on the KM design developing C sands with possible future optimization on gravel pack length and completion tubing size to optimize completion for liquids handling to maximize recovery factor. A late life workover will be required to produce the B sands through a cased hole gravel pack

A SMART well completion has been excluded based on its reduced productivity as well as its increased cost, complexity and operational risk. During Detailed Design the final completion design will be optimised for stand-off from the GWC to allow deferred water breakthrough and tubing size may be reduced in order to optimise liquid handling capacity. The reference case completion design for Karish North wells are to maintain the Karish Main design.

At present a KN02 deviated well based on learnings from the Karish Main well is deemed to be the optimal solution as it negates additional facilities costs and enhances hydrate management, however, the facilities designs allows for this decision to be deferred until immediately prior to KN02 drilling.

8 Project Schedule and Costs

8.1 Project Schedule

The base case project schedule assumes that KN01 is brought online in 2022 with KN02 not being brought online until 2026. This is based on the anticipated gas sales contracts and assumes that Karish North Fluids are used to supply the additional gas sales contracts that are entered into for its volumes. It may be possible to accelerate Karish North production in order to accelerate liquids b deferring lower yield Karish Main volumes. It is slos worth noting that a single XT was ordered in September 2019 with specifications to meet the additional functionality required of a KN01. This XT is scheduled for delivery by the end of June 2021. The current lead times suggest that if a second XT for KN02 were to be ordered at FID, then it would not be available in time for the proposed KN01 drilling and completion campaign in late 2021, therefore schedule optimisation to install all Karish North facilities and wells in a single phase has not been performed.

In terms of a project schedule, all facilities concepts discussed in section 7 are divided into two phases with the first phase installing a subsea tieback to the Karish Main Manifold and hook-up of the KN01 well and the second phase involving hook-up of the KN02 well, with the possibility of this phase also including installation of a second flowline for those concepts with dual flowline tiebacks.

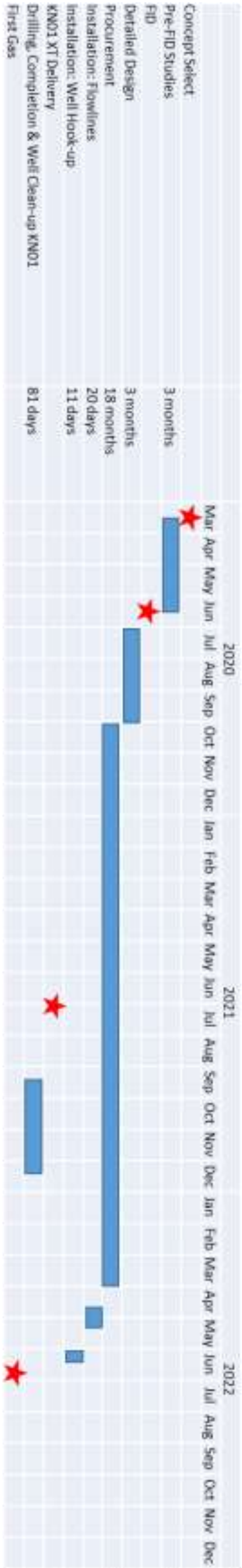


Figure 8-2 – Karish North Phase 1 Project Schedule

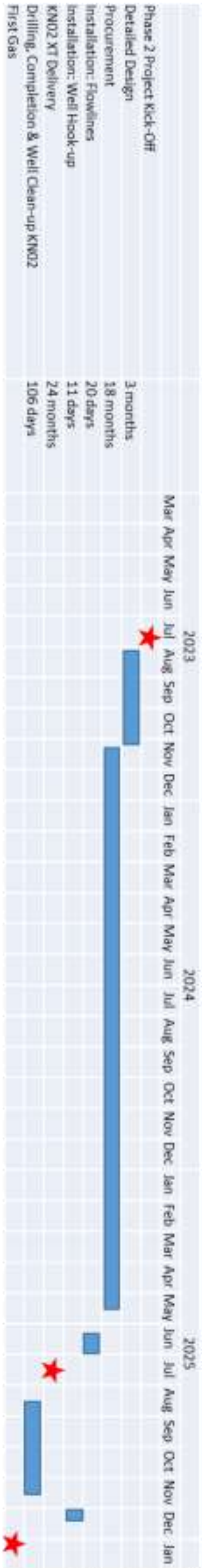


Figure 8-1 – Karish North Phase 2 Project Schedule

8.2 Project Costs

8.2.1 Facilities Costs

TFMC have provided costs for the A-1, A-2 and B-1 concepts discussed above to an accuracy of -10%/+40%, including a breakdown by phase of the project.

		£M	US$M	Contingency (25%)	Owner's Costs	TOTAL
Single Flowline A-1	**Ph1**	62.4	76.1	19.0	7.6	**102.8**
KN02 deferred	**Ph2**	14	17.1	4.3	1.7	**23.1**
					TOTAL	**125.8**
Single Flowline A-2	**Ph1**	55	67.1	16.8	6.7	**90.6**
KN02 deferred	**Ph2**	14	17.1	4.3	1.7	**23.1**
					TOTAL	**113.6**
Dual Flowline B-1	**Ph1**	79.5	97.0	24.2	9.7	**130.9**
KN02 deferred	**Ph2**	14	17.1	4.3	1.7	**23.1**
					TOTAL	**154.0**
Dual Flowline B-1	**Ph1**	59.5	72.6	18.1	7.3	**98.0**
2nd Line & KN02 deferred	**Ph2**	46.2	56.4	14.1	5.6	**76.1**
					TOTAL	**174.1**

Notes:
1. Accuracy of TFMC estimate of -10%/+40%
2. £=1.22$
3. Contingency of 25% applied
4. Owner's costs= 10% of base estimate
5. Excludes geotechnical surveys and Xmas Trees
6. Excludes taxes due to importation of material and vessels to Israel
7. Excludes in-Israel security

Table 8-1 – Facilities CAPEX Estimates

Table 8-1 shows that the lowest overall cost option is a single flowline tieback with KN02 drilled as a deviated well from KN01 (concept A-2). If KN02 is a vertical well then the costs of the additional infrastructure required to tie-in the well at the Karish North PLEM, although not yet quantified by TFMC, will be higher that the additional costs of moving to the A-1 concept where the flowline to KN02 is installed upfront with an ILT at KN01, thus reducing the infrastructure required.

The CAPEX estimates also show that the phase 1 cost of installing a dual 10" flowline (case B-1) with installation of the second line tied in when KN02 is drilled, are similar to the single flowline cases (A-1 and A-2), although deferral does increase the overall cost estimate for this concept by 13% compared to installing both flowlines in Phase 1.

In terms of detailed phasing of costs covering both phases of the project, these are detailed in **Table 8-2** below.

	Total (MUSD)	Ph1 (MUSD)	Ph2 (MUSD)	2020	2021	2022	2023	2024	2025
Single A-1	**125.8**	**102.8**	**20.8**	10.3	41.1	51.4	2.3	9.2	11.5
Single A-2	**113.6**	**90.6**	**20.8**	9.1	36.2	45.3	2.3	9.2	11.5
Dual to KM Manifold B-1	**154.0**	**133.2**	**20.8**	15.4	52.4	65.5	0.0	8.3	12.5
Dual to KM Manifold B-1 2nd F/L Deferred	**174.1**	**98.0**	**68.5**	9.8	39.2	49.0	7.6	30.4	38.0

Table 8-2 – Facility CAPEX Phasing by Year

8.2.2 Well Costs

Well costs have been developed for both the conversion of KN01 to a development wellbore KN01-ST04 (as per section 7.2.2.4) and for a new development well, KN02 with a tophole location ~50m from KN01 and a downhole target location with approximately 1.1km step-out (see section 7.2.2.5).

These cost estimates (see **Table 8-3** & **Appendix 2**) are based on two campaigns including their mobilisation and campaign planning activities:

1. 2H 2021 Campaign: KN01-ST04
   Re-enter well, drill and complete (including 1x coring and 2x wireline runs).
   Part of a 4 well campaign where planning and mobilization costs are evenly split (25% allocation).
2. 2025 Campaign: KN02
   Drill new well including reservoir pilot hole c/w 1x coring and 4x wireline runs. P&A pilot hole then side track to drill development wellbore and install completion.
   Part of a 4 well campaign where planning and mobilization costs are evenly split (25% allocation).

Costs: US$M +/-15% Duration- days	2H 2021 Rig Rate= $200k/d KN01-ST04 Re-enter, side track and complete	2025 Rig Rate= $250k/d KN02 Drill and complete c/w pilot hole
Campaign Planning	$2.25M / -	$2.25M / -
Mobilisation	$3.91M / 13d	$4.30M / 13d
Drilling/Completion Ops	$50.89M / 69d	$75.01M / 56d
TOTAL	$57.05M / 82d	$81.56M / 37d

Table 8-3 – Karish North Drilling Cost Estimates

	2H 2021 KN01-ST04	2025 KN02
Rig Rate	$200k/d	$250k/d
Drilling/Completion/PM Rates	2019 rates +15%	2019 rates +25%
Logistics	2019 rates + 8% uplift	2019 rates + 10% uplift
Campaign Planning	12 month duration	12 month duration
Mobilisation Location	Las Palmas	Las Palmas
Xmas Trees	Included	Included
Uncertainty	+/-15%	+/-15%

Table 8-4 – Cost Estimate Assumptions

8.3 Reference Karish North Development Scenario

Based on the discussions regarding Concepts A-1, A-2 and B-1 above it is recommended that, pending formal Concept Selection, that Concept A-2, i.e. a single flowline tied back to the Karish Main Manifold is the reference case for the development. As reminder, the key concept selection criteria are:

- Economic performance (NPV, P/I, CAPEX)
- Maximised recovery: both gas and liquids
- Maximising capacity of Karish Main + Karish North to achieve FPSO design throughput

- Low operational complexity

These are maximised in the A-2 scenario due to:

- Lowest CAPEX
- Ability to install a future second flowline
- Allows continued round trip pigging

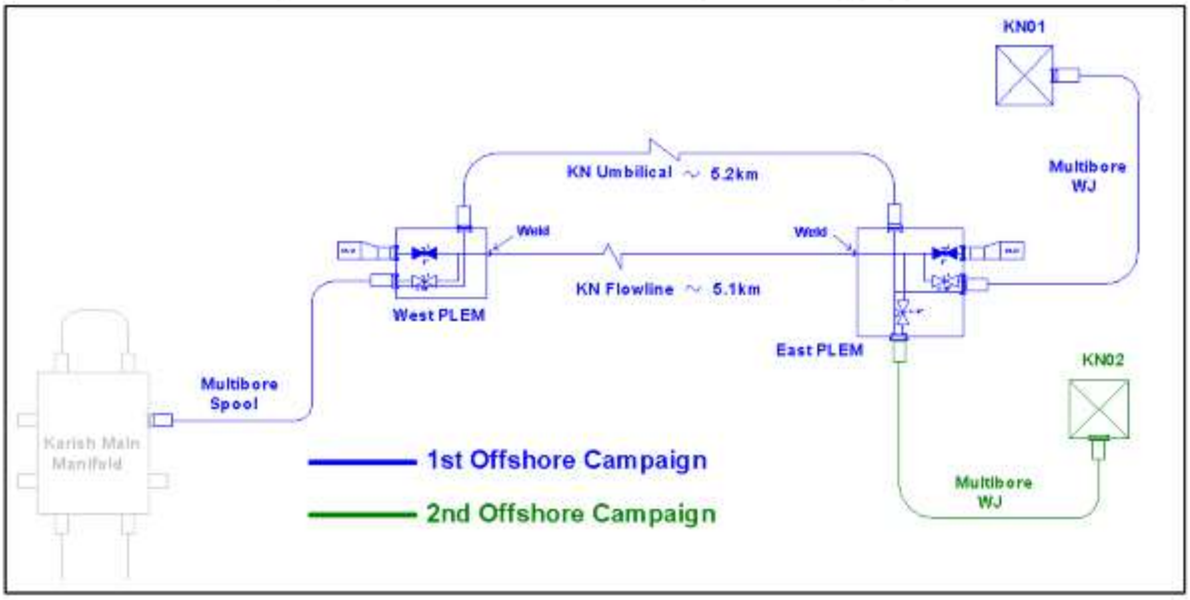


Figure 8-3 – Reference Case Development Schematic

This estimate does not include drilling and tieback of KN02 nor the costs associated with a KN01 workover for B sands production and it is based on costs provided by TFMC prior to drilling of Karish North, however, as can be seen these costs are ~10% higher than option A-2's cost estimates provided as part of the Conceptual Selection.

MAIN COST ITEMS	SUB COST ITEM	END CONCEPT PHASE ESTIMATE (US$ mln)
KN-1 ST4	Rig hire	14
	Services	21
	Tangibles	16
	Planning and management	6
	Total	**57**
Karish North Subsea	Project Management	3
	SPS Hardware	22
	Flowlines	20
	Umbilicals	7
	Spools	1
	Installation	27
	Contingency (25%)	20
	Total (inc. Contingency)	**100**
2nd 16" Riser	**Total (inc. Contingency)**	**41**
Total	**Phase 1**	**198**

Table 8-5 – Reference Case Deterministic Cost Estimate

The deterministic project facilities schedule for the reference case is detailed in **Figure** and **Error! Reference source not found.** below which shows the well-related activities split into two phases. The first occurs in late 2020 with the sidetrack of KN01 to the KN01-ST04 location where the casing shoe will be set 2m into the Upper C sands.

9 Gas Sales

Energean Israel Limited have negotiated a number of additional gas contracts based on the Karish North discovered resources, these have been used to calculate the base capacity available for Karish North Production and will be finalised during mid-2020. Further contracts expected to be agreed by the end of the year providing a high case capacity available for Karish North production.

10 Economics

Economics will be prepared and submitted post development of an updated, integrated Karish Main, Karish North and Tanin production forecast based on all information gathered during Karish Main Development Drilling, this will be before FID.

11 Project Execution Plan

A dedicated Karish North Project manager will be appointed who will follow the same general principles of Project Execution as defined for the subsea facilities for the Karish Main project.

11.1 Contracting Strategy

11.1.1 Facilities Contracting Strategy

The current contracting strategy is to leverage the knowledge within the TFMC team to deliver the facilities related aspects of the project respectively. This not only reduces interfaces, but also ensures that project learnings are carried forward into the engineering, procurement and execution phases of the Karish North Project. TFMC will perform FEED in parallel with FDP approval allowing for a lump sum contract to be awarded at FID.

The incumbent verification and environmental contractors, DNV-GL and ERM will also be retained.

11.1.2 Well Delivery Contracting Strategy

The well delivery contracting strategy is to continue with the approach taken to deliver the Karish Main production and recent exploration wells. **Figure 11-1** defines the responsibilities of the various contractors.

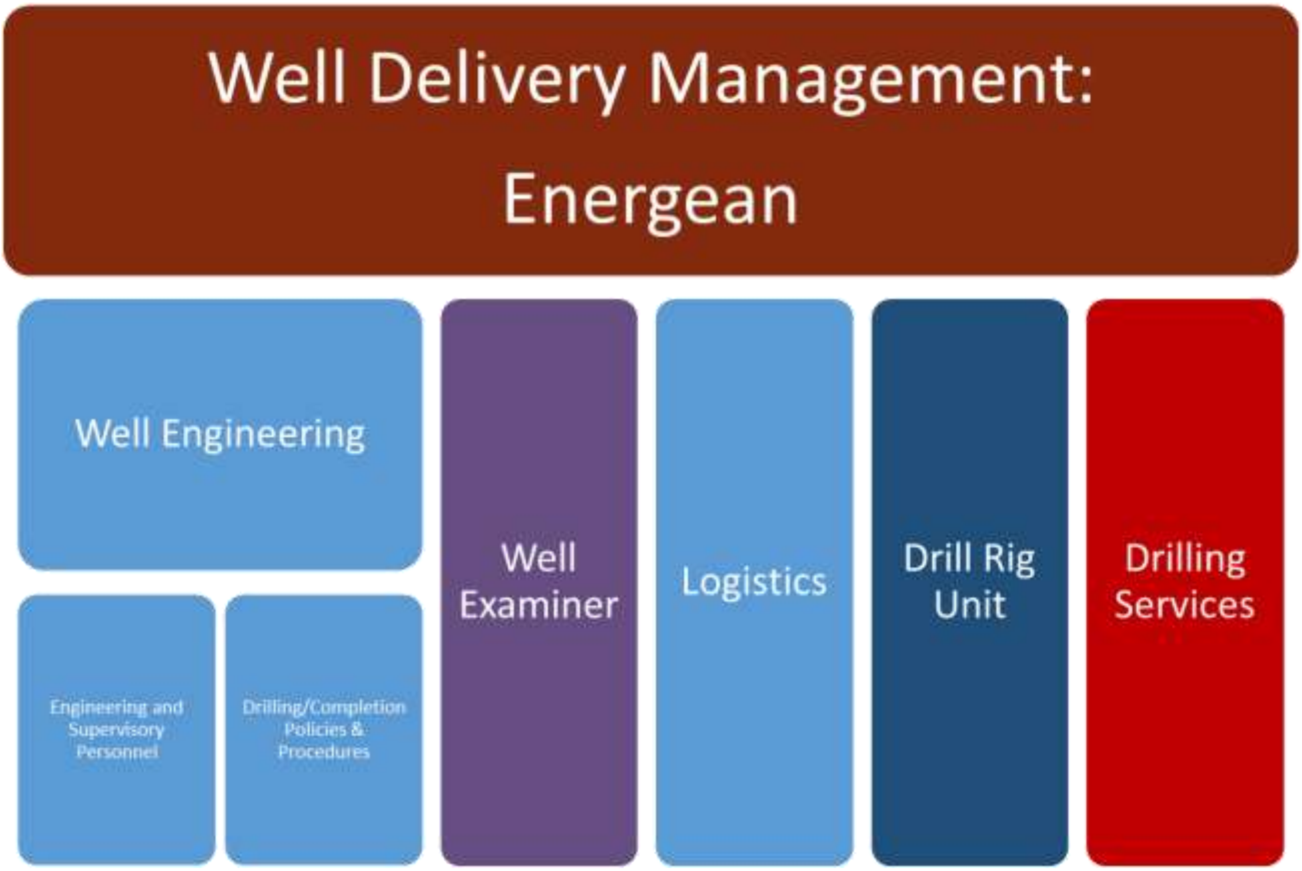


Figure 11-1 - Well Delivery Contracting Strategy

11.2 Karish North Abandonment

11.2.1 Subsea Infrastructure

The Karish North subsea infrastructure is anticipated to be abandoned at the same time as the Energean Power is taken off station and decommissioned despite the expectation that Karish and Karish North will cease production prior to production through the Energean Power FPSO from Tanin and future tiebacks. This is because removal of the sub-surface infrastructure and well abandonment activities are expected to cause more cost and risk to the ongoing production than ongoing maintenance activities. In terms of the abandonment process all systems will be purged of hydrocarbons, cleaned from any debris related to production and flooded with seawater and then the Karish North PLEMs and short spools will be removed. The main KN01 flowline will be left in-situ flooded with seawater as they represent no harm to the environment. More detailed cost estimates for removal of the subsurface facilities will be defined as cessation of production from Karish and Karish North approaches to enable a risk and cost based decision to be made.

11.2.2 Wells

At a high level current well abandonment estimates, based on the philosophy detailed for Karish Main wells in the original FDP, for each well require a rig for 30 days a rate of U$340,000 per day resulting in an abandonment cost per well of US$10.2M.

12 Operations and Maintenance

The Operating Philosophy for Karish North on production will follow that of the, by then, producing Karish Main field with no anticipated increase in offshore manning during normal operations. The only deviation is for the Development and Project Phases, as the Operations & Maintenance team will be focused on pre-commissioning, commissioning, start-up and production of the Karish Main field, it will not be possible them to prepare procedures, etc. for Karish North. It is expected that WOOD, who have been heavily involved during the Operations Readiness phase of K=the Karish Main project will be seconded into the project in a similar role to support during the run-up to installation and commissioning activities. Including updating all of the relevant operating documentation to cover the KN wells and facilities.

13 Health, Safety, Environment and Security

In the original FDP, it is stated that Energean was in the process of defining its HSE Management System, which would be applied to the Karish and Tanin Developments. This system has since been developed covering all aspects of project Hazard, Environmental, Emergency Response, Performance, Change, Risk and Security Management.

14 Local Content Development

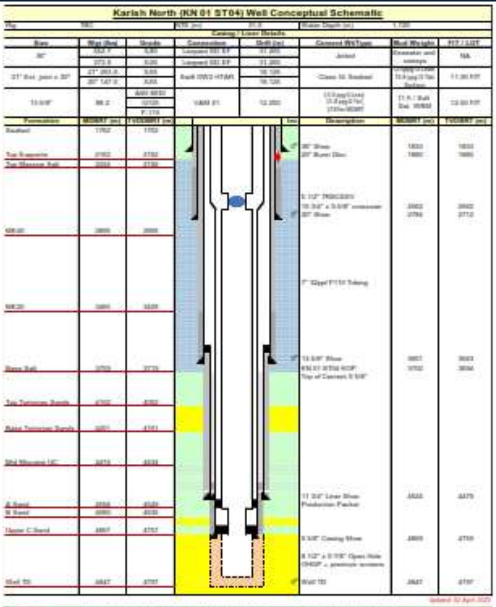
Opportunities will be identified for scopes to be tendered to Israeli contractors, Given that the majority of the facilities scope will be awarded as a lump sum contract to a specialist, global contractor, it is likely that Israeli contractors are most likely to be awarded scopes in support of the Karish North drilling campaigns.

Appendix 1: Karish North Exploration & Appraisal Well Correlation Panel

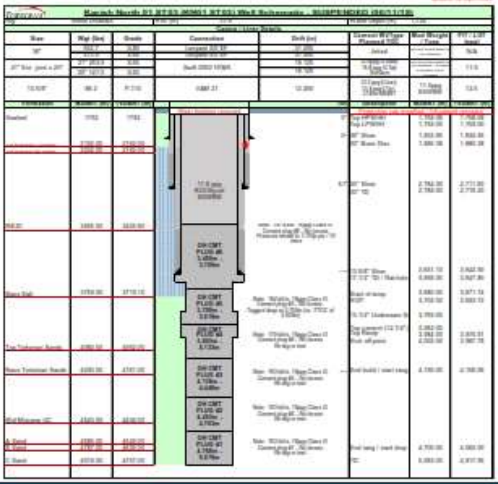
Appendix 2: Well Cost Estimates

KN 01 ST 04 DRILL & COMPLETE WELL BUDGETARY WELL COST ESTIMATE SUMMARY SHEET

Karish North (KN 01 ST04) Well Conceptual Schematic



Karish North 01 ST03 (KN01 ST03) Well Schematic - SUSPENDED



Well Timing & Cost Assumptions

1. The trajectory is drilled from the existing KN 01 ST03 wellbore.
2. Drilling timing includes, preparation, BOP installation, drilling, casing, Tx coring run and 2x wireline runs.
3. Completion timing includes, drilling reservoir section, WBCO, lower completion, XT installation, upper completion and well clean up.
4. Timings are based from 2019/2020 Karish Main actual drilling and Completion performance.
5. Well timing commences when rig is on location and BOP is ready to run.
6. Well timing finishes when BOP is secured back on the hooks.
7. Well construction sequence assumes drilling and completion is performed as a single activity (no suspension included).
8. Timings based on 6th generation DP drillship with dual activity utilised.
9. Only a primary set of tangible equipment is assumed in the costs.
10. 5" horizontal XT is assumed to be installed from rig.
11. The gravel pack operation is assumed to be rig based, with NO dedicated stimulation vessel requirement.
12. All costs are in USD & operations to be performed in Q3 2021
13. A rig rate of $200K per day is assumed.
14. Drilling, Completion and PM rates are based on 2019 + 10% uplift.
15. Logistics rates are based on 2019 + 8% uplift.
16. 12 months planning cycle assumed for the development drilling team.
17. Campaign planning includes the estimated costs of personnel, engineering studies, rig start up, audits, IT, freight and customs costs.
18. Rig assumed to mobilise from Las Palmas.
19. Campaign pre-drill and post-drill costs are split across 4 wells - 25% allocation to this well (except completion services and post drill survey)
20. Estimate carries +/-15% uncertainty based on level of definition at budget setting time.

WELL TIME ESTIMATE

DATE: 01 Apr 2020

MOBILISATION / DEMOBILISATION	Distance nautical miles	Speed knots	Budget days
Las Palmas (Canary Islands) -> Karish North (Israel)	3061	10.0	12.8
Mobilisation / Demobilisation Time			12.8

DRILLING OPERATIONS	Depth m	Incremental Days	Cum. Budget days
Drill: Local mobilisation	0	1.00	1.0
Drill: Run riser/BOP and latch	0	2.50	3.5
Drill: (12-1/4" x 14-3/4") Run BHA, drill cement	3450	2.00	5.5
Drill: (12-1/4" x 14-3/4") Drill Hole to TD	4524	1.75	7.3
Drill: (12-1/4" x 14-3/4") Recover and lay out BHA	4524	2.00	9.3
Drill: (12-1/4" x 14-3/4") Run and cement 11-3/4" Liner	4524	3.52	12.8
Drill: (12-1/4") Run BHA, drill cement	4524	2.00	14.8
Drill: (12-1/4" Drill to core point	4600	0.75	15.5
Drill: (12 1/4") Recover and L/out BHA	4600	1.67	17.2
Drill: (12-1/4") Core Reservoir	4630	4.08	21.2
Drill: (12 1/4") Run BHA	4630	2.00	23.2
Drill: (12 1/4") Drill Hole To TD	4807	0.75	24.0
Drill: (12 1/4") Recover and lay out BHA	4807	1.67	25.7
Drill: (12 1/4") Wireline	4807	2.33	28.0
Drill: (12 1/4") Run and cement 10 3/4" x 9 5/8" casing	4807	3.52	31.5
Comp: (8-1/2" x 9-7/8") Run BHA, Drill Shoe Track, LOT	4807	4.00	35.5
Comp: (8-1/2" x 9-7/8") Drill Hole	4847	0.85	36.4
Comp: (8-1/2" x 9-7/8") Recover and L/out BHA	4847	0.55	37.0
Comp: Wellbore cleanout	4847	2.75	39.8
Comp: Run lower completion and set packer	4847	1.90	41.7
Comp: Pump gravel pack	4847	0.75	42.4
Comp: POOH with gravel pack service tool and layout	4847	1.20	43.6
Comp: Unlatch BOP and run XT on auxiliary well centre	4847	2.40	46.0
Comp: Latch BOP on XT and pressure test	4847	0.40	46.4
Comp: Rigidise WH/CH/XT and pull Bore Protector	4847	0.53	46.9
Comp: Run upper completion	4847	2.55	49.5
Comp: Make-up Tubing Hanger	4847	1.30	50.8
Comp: Run completion on landing string	4847	2.60	53.4
Comp: Make-up surface equipment	4847	0.65	54.0
Comp: Land and lock tubing hanger, set packer and test	4847	3.20	57.2
Comp: Carry out well clean-up to the rig	4847	3.60	60.8
Comp: Inflow test TRSCSSV, lubricate string, set/test TH crown plugs	4847	1.9	62.7
Comp: Recover landing string and install lock-down	4847	3.0	65.7
Comp: Unlatch and recover BOP, install debris cap	4847	3.0	68.7
Total Time - Well Execution:			68.7

	Budget Time
MOBILISATION:	13
DRILLING:	32
COMPLETION / WELL TEST:	37
TOTAL WELL BUDGET TIMING:	81 days

BUDGETARY WELL COST ESTIMATE

WELL NAME	Karish North Drilling	Mob/Demob Days	13
LICENSE BLOCK	Karish , Israel	Drilling Days	32
WELL TYPE	Development	Completion Days	37
TOTAL DEPTH	5,083m MD / 4,918m TVD		

Long Lead Equipment & Consumables (Per Well)	Unit Cost USD	No of Units	TOTAL USD
Large diameter casing (36" and 20")	-	1	0
Casing, Liner, Liner Hanger (11-3/4", 10-3/4" & 9-5/8")	[illegible]	1	[illegible]
Casing Accessories	[illegible]	1	[illegible]
Drill Bits/mills	[illegible]	1	[illegible]
Drilling Fluid Product and Chemicals	1,200,000	1	1,200,000
Cement Product and Chemicals	700,000	1	700,000
Completion Fluids: RDF, Completion Brine, Gravel Pack Products and Chemicals	1,000,000	1	1,000,000
Completion equipment	2,200,000	1	2,200,000
Completion tubing	[illegible]	1	[illegible]
Surface well testing/clean-up package consumables	300,000	1	300,000
5" Horizontal XT + SCM + Tubing Hanger	[illegible]	1	[illegible]
Fuel (Rig + 2x PSVs) Ops Only - Excludes Mob and Demob	[illegible]	1	[illegible]
Fuel (Rig) - Mob Only (25% Share to KN 01)	900,000	0.25	225,000
SUB TOTAL (Long Leads/Consumables)			[illegible]

Time Driven Costs (Per Well)	Unit Cost USD	No of Units	TOTAL USD
Rig Rate	200,000	69	13,748,[illegible].72
Drilling Services Rate	[illegible]	47	[illegible]
Completion Services Rate	[illegible]	68	[illegible]
Personnel and Project Management Rate	[illegible]	69	[illegible]
Logistics Services Rate	[illegible]	69	[illegible]
SUB TOTAL (Well)			[illegible]

Total Well Cost **50,888,000 USD**

Campaign Mobilisation / Demobilisation (Per Campaign)	Unit Cost USD	No of Units	TOTAL USD
Mobilisation & Demobilisation - Rig (50% of ops rate) (25% Share to KN 01)	[illegible]	[illegible]	[illegible]
Mobilisation & Demobilisation - Completion Services (50% of ops rate) (100% Share to KN 01)	[illegible]	[illegible]	[illegible]
Mobilisation & Demobilisation - Drilling Services (30% of ops rate) (25% Share to KN 01)	[illegible]	[illegible]	[illegible]
SUB TOTAL (Mob/Demob)			[illegible]

Campaign Planning (Per Campaign)	Unit Cost USD	No of Units	TOTAL USD
Planning Cost (Energean, LR, 3rd Party, Studies, IT, Freight & Customs) (25% Share to KN 01)	[illegible]	[illegible]	[illegible]
Wrap-up Cost (Energean, LR, 3rd Party, Freight & Customs) (25% Share to KN 01)	[illegible]	[illegible]	[illegible]
Pre-Drill Site Survey	-	[illegible]	-
Post-Drill Site Survey (100% Share to KN 01)	[illegible]	1.00	[illegible]
SUB TOTAL (Planning)			[illegible]

Total Campaign Cost **57,045,000 USD**

COST ESTIMATE APPROVALS:

Well Delivery Manager

1st April 2020

DATE

Chief Growth Officer

DATE

KN 02 ST 01 DRILL & COMPLETE WELL BUDGETARY WELL COST ESTIMATE SUMMARY SHEET

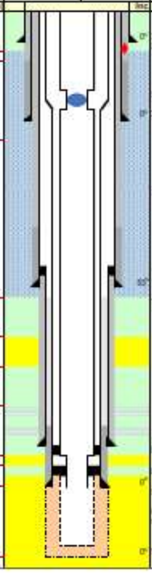
Karish North KN 02 (Deviated) Well Conceptual Schematic - NOT TO SCALE

Rig	Stena DrillMAX	RTE (m)	31.8	Water Depth (m)	1,730

Casing / Liner Details

Size	Wgt (lbs)	Grade	Connection	Drift (in)	Cement Wt/Type	Mud Weight	FIT / LOT
36"	552.7	X-80	Leopard SD EF	31.265	NA	Seawater and sweeps	NA
	373.9	X-56	Leopard SD EF	31.265			
21" Ext. joint x 20"	21" 283.9	X-65	Swift DW2 HTAR	18.125	Class G/ Seabed	[illegible]	11.90 FIT
	20" 147.0	X-65		18.125			
13 5/8"	88.2	AISI 8630 / Q125 / P-110	VAM 21	12.250	[illegible]	11.5 / Salt Sat. WBM	12.50 FIT

Formation	MDBRT (m)	TVDBRT (m)
Seabed	1762	1762
Top Evaporite	2162	2162
Top Massive Salt	2182	2182
ME40	2695	2695
Base Salt	3850	3719
Top Tortonian Sands	4356	4062
Base Tortonian Sands	4477	4181
Mid Miocene UC	4773	4434
A Sand	4891	4549
B Sand	4976	4635
Upper C Sand	5100	4757
Well TD	5140	4757



Inc.	Description	MDBRT (m)	TVDBRT (m)
0°	36" Shoe	1834	1834
	20" Burst Disc	1884	1884
	5 1/2" TRSCSSV		
	10 3/4" x 9 5/8" crossover	2562	2562
0°	20" Shoe	2845	2845
	7" 32ppf P110 Tubing		
	11 3/4" Liner Hanger	3852	3483
93°	13 5/8" Shoe	3852	3582
	Top of Cement 9 5/8"	4208	
	11 3/4" Liner Shoe	4821	
	Production Packer		
	Liner Hanger Packer		
0°	9 5/8" Casing Shoe	5103	4760
	8 1/2" x 9 7/8" Open Hole DHGP + premium screens		
0°	Well TD	5140	4757

Well Timing & Cost Assumptions

[illegible]

WELL TIME ESTIMATE

DATE: 01 Apr 2020

MOBILISATION / DEMOBILISATION	Distance nautical miles	Speed knots	Budget days
Las Palmas (Canary Islands) -> Karish North (Israel)	3061	10.0	12.8
Mobilisation / Demobilisation Time			12.8

DRILLING OPERATIONS	Depth m	Incremental Days	Cum. Budget days
Drill: Local mobilisation	0	0.10	0.1
Drill: Prepare to Spud	0	1.00	1.1
Drill: Spud Well - Jet Conductor (36")	1834	0.55	1.7
Drill: Top Hole (24") - Drill Hole	2845	2.91	4.6
Drill: Top Hole (24") - Recover and L/out BHA	2845	0.16	4.7
Drill: Top Hole (24") - Run & Cement Casing (20")	2845	1.38	6.1
Drill: Latch BOP	2845	0.83	7.0
Drill: Intermediate Hole #1 (17-1/2") - Run BHA, Drill Shoe Track and LOT	2845	0.85	7.9
Drill: Intermediate Hole #1 (17-1/2") - Drill Hole To TD	3800	2.03	9.9
Drill: Intermediate Hole #1 (17-1/2") - Recover and L/out BHA	3800	0.82	10.7
Drill: Intermediate Hole #1 (17-1/2") - Run & Cement Casing (13-5/8")	3800	4.98	15.7
Drill: Intermediate Hole #2 (12-1/4" x 14-3/4") Run BHA, Drill Shoe Track and LOT	4821	2.00	17.7
Drill: Intermediate Hole #2 (12-1/4" x 14-3/4") Drill Hole to TD	4821	1.75	19.5
Drill: Intermediate Hole #2 (12-1/4" x 14-3/4") Recover and Lay Out BHA	4821	2.00	21.5
Drill: Intermediate Hole #2 (12-1/4" x 14-3/4") Run and Cement 11-3/4" Liner	4821	3.52	25.0
Drill: Pilot Hole #1 (8-1/2") - Run BHA, Drill Shoe Track and LOT	4821	2.00	27.0
Drill: Pilot Hole #1 (8-1/2") - Drill Hole To Core Point	5100	0.75	27.7
Drill: Pilot Hole #1 (8-1/2") - Recover and L/out BHA	5100	1.67	29.4
Drill: Pilot Hole #1 (8-1/2") - Core Reservoir	5100	4.05	33.5
Drill: Pilot Hole #1 (8-1/2") - Run BHA	5100	2.00	35.5
Drill: Pilot Hole #1 (8-1/2") - Drill Hole To TD	5500	0.08	35.5
Drill: Pilot Hole #1 (8-1/2") - Wireline	5500	5.00	40.5
Drill: Pilot Hole #1 (8-1/2") - P&A	5500	3.00	43.5
Drill: Side Track #1 (8-1/2" x 12-1/4") - Run BHA, Drill cement	3800	3.37	46.9
Drill: Side Track #1 (8-1/2" x 12-1/4") - Drill Hole To TD	5103	3.99	50.9
Drill: Side Track #1 (8-1/2" x 12-1/4") - Recover and L/out BHA	5103	1.67	52.6
Drill: Side Track #1 (8-1/2" x 12-1/4") - Run & Cement Casing (10 3/4")	5103	3.52	56.1
Comp: (8-1/2" x 9-7/8") Run BHA, Drill Shoe Track, LOT	5140	4.00	60.1
Comp: (8-1/2" x 9-7/8") Drill Hole	5140	0.85	60.9
Comp: (8-1/2" x 9-7/8") Recover and L/out BHA	5140	0.65	61.6
Comp: Wellbore cleanout	5140	2.75	64.3
Comp: Run lower completion and set packer	5140	1.90	66.2
Comp: Pump gravel pack	5140	0.75	67.0
Comp: POOH with gravel pack service tool and layout	5140	1.20	68.2
Comp: Unlatch BOP and run XT on auxiliary well centre	5140	2.40	70.6
Comp: Latch BOP on XT and pressure test	5140	0.40	71.0
Comp: Rigidise WH/CHXT and pull Bore Protector	5140	0.53	71.5
Comp: Run upper completion	5140	2.55	74.1
Comp: Make-up Tubing Hanger	5140	1.30	75.4
Comp: Run completion on landing string	5140	2.60	78.0
Comp: Make-up surface equipment	5140	0.65	78.6
Comp: Land and lock tubing hanger, set packer and test	5140	3.20	81.8
Comp: Carry out well clean-up to the rig	5140	3.60	85.4
Comp: Inflow test TRSCSSV, lubricate string, set/test TH crown plugs	5140	1.9	87.3
Comp: Recover landing string and install lock-down	5140	3.0	90.3
Comp: Unlatch and recover BOP, install debris cap	5140	3.0	93.3
Total Time - Well Execution:			93.3

	Budget Time
MOBILISATION:	13
DRILLING:	56
COMPLETION / WELL TEST:	37
TOTAL WELL BUDGET TIMING:	106 days

BUDGETARY WELL COST ESTIMATE

WELL NAME	Karish North 02 Drill and Complete	Mob/Demob Days	13
LICENSE BLOCK	Karish , Israel	Drilling Days	56
WELL TYPE	Appraisal Pilot Hole + Development	Completion Days	37
TOTAL DEPTH	5,500m MD / 5,157m TVD		

Long Lead Equipment & Consumables (Per Well)	Unit Cost USD	No of Units	TOTAL USD
Large Diameter Casing (36" and 20")	400,000	1	400,000
Casing, Liner, Liner Hanger (13-5/8", 11-3/4", 10-3/4" & 9-5/8")	800,000	1	800,000
Casing Accessories	1,000,000	1	1,000,000
Drill Bits/mills	150,000	1	150,000
Drilling Fluid Product and Chemicals	200,000	1	200,000
Cement Product and Chemicals	1,800,000	1	1,800,000
Completion Fluids, RDF, Completion Brine, Gravel Pack Products and Chemicals	1,000,000	1	1,000,000
Completion equipment	2,200,000	1	2,200,000
Completion tubing	800,000	1	800,000
Surface well testing/clean-up package consumables	300,000	1	300,000
5" Horizontal XT + SCM + Tubing Hanger	[illegible]	1	[illegible]
Fuel (Rig + 2x PSVs) Ops Only - Excludes Mob and Demob	[illegible]	1	[illegible]
Fuel (Rig) - Mob Only (25% Share to KN 02)	[illegible]	0.25	[illegible]
SUB TOTAL (Long Leads/Consumables)			19,102,000

Time Driven Costs (Per Well)	Unit Cost USD	No of Units	TOTAL USD
Rig Rate	[illegible]	93	[illegible]
Drilling Services Rate	[illegible]	84	[illegible]
Completion Services Rate	100,000	56	[illegible]
Personnel and Project Management Rate	37,500	93	[illegible]
Logistics Services Rate	71,500	93	[illegible]
SUB TOTAL (Well)			[illegible]

Total Well Cost 75,011,000 USD

Campaign Mobilisation / Demobilisation (Per Campaign)	Unit Cost USD	No of Units	TOTAL USD
Mobilisation & Demobilisation - Rig (50% of ops rate) (25% Share to KN 02)	125,000	3	[illegible]
Mobilisation & Demobilisation - Completion Services (50% of ops rate) (100% Share to KN 02)	50,000	60	[illegible]
Mobilisation & Demobilisation - Drilling Services (30% of ops rate) (25% Share to KN 02)	[illegible]	15	[illegible]
SUB TOTAL (Mob/Demob)			[illegible]

Campaign Planning (Per Campaign)	Unit Cost USD	No of Units	TOTAL USD
Planning Cost (Energean, LR, 3rd Party, Studies, IT, Freight & Customs) (25% Share to KN 02)	4,000,000	0.25	1,000,000
Wrap-up Cost (Energean, LR, 3rd Party, Freight & Customs) (25% Share to KN 02)	2,000,000	0.25	500,000
Pre-Drill Site Survey	-	0.00	-
Post-Drill Site Survey (100% Share to KN 02)	700,000	1.00	700,000
SUB TOTAL (Planning)			2,200,000

Total Campaign Cost 81,560,000 USD

COST ESTIMATE APPROVALS

Well Delivery Manager

1st April 2020

DATE

Chief Growth Officer

DATE