adani
WELSPUN

Ref No: AWEL/EIA/01/2019

Date: 17th July 2019

To,
The Director,
IA Division (Industry-II)
Ministry of Environment Forest and Climate Change (MoEF & CC),
Indira Paryavaran Bhawan
Jor Bagh, New Delhi- 110003

Subject : Submission of EIA Addendum Report of Offshore Oil and Gas Development and Production from Discovered Small Field of B-9 Cluster fields at Mumbai Offshore Basin - EC Regarding.

Ref : Agenda for 6th Expert Appraisal Committee (Industry-2) meeting held during 8-9 April 2019.

Dear Sir,

With reference to the subject line, we are hereby submitting the EIA Addendum Report of "Offshore Oil and Gas Development and Production from Discovered Small Field of B-9 Cluster fields at Mumbai Offshore Basin", in compliance to the terms and conditions given in minutes of 6th EAC (Industry-2) meeting held during 8-9 April 2019 (Agenda no. 6.3.3).

In view of above, we hereby request you to kindly review the enclosed report and consider the project in upcoming EAC meeting.

We look forward to your kind corporation.

Thanking You,

For Adani Welspun Exploration Limited.

17/07/19
(Arvind Hareendran)
Vice President-Operations

Enclosures: as above

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ADDENDUM REPORT

of

EIA Study for Offshore Oil & Gas Development and Production from Discovered Small Field of B-9 Cluster Offshore Fields at Mumbai Offshore Basin.

In compliance to the Terms and Conditions

as per Agenda no. 6.3.3 & *minutes of 6th EAC (Industry-2) meeting held on dated 8-9 April 2019.*

Terms and Conditions are as follows:

1. *Baseline air quality of the areas immediately affected by the development drilling, particularly with reference to Hydrogen Sulphide, Sulphur Dioxide, NOx and background levels of Hydrocarbons and VOCs.*

2. *Details on estimation and computation of air emissions (such as Nitrogen Oxides, Sulphur Oxides, Carbon Monoxide, Hydrocarbons, VOCs, etc.) resulting from flaring, DG sets, combustion, etc. in all project phases.*

3. *Baseline data collection within 1km of each development well, in respect of oil/metal/hydrocarbon content in the surface water and sediments.*

4. *Details of DG Sets and other utilities.*

5. *Prediction of various parameters vis-à-vis estimated gas production.*

6. *Source of fresh water, water balance and effluent treatment mechanism.*

7. *Procedure for handling oily water discharges from deck washing, drainage systems, bilges, preventing spills and spill contingency plans, treatment and disposal of produced water.*

8. *Details of blowout preventer installation.*

9. *Risk assessment and mitigation measures including independent reviews of well design, drilling and proper cementing and casing practices.*

10. *Details of all environment and safety related documentation within the company (regarding Life of pipeline, Corrosion prevention method, inspection etc.)in the form of guidelines, manuals, monitoring programmes including Occupational Health Surveillance Programme etc.*

11. *Applicability of OISD Standards.*

The compliance of above points is explained herewith in detail:

1. **Baseline air quality of the areas immediately affected by the development drilling, particularly with reference to Hydrogen Sulphide, Sulphur Dioxide, NOx and background levels of Hydrocarbons and VOCs.**

   Reply: The project site is about 72 km from Diu coast in the sea. There are no developmental activities at site (platform, well head, etc.). There is no human habitation at site or within 10 km from the development drilling locations. The nearest developmental activity is at B-12 development area of ONGC at about 50 km away from the project location. Hence baseline air quality of the area is not available. It is expected that air quality within 10 km from the project site is pristine as there is neither any human habitation nor any anthropogenic activity in the area. The area is being in deep sea, there is always heavy wind and hence dispersion of pollutants from the proposed development well be very fast. The emissions from the proposed developmental drilling are calculated and given in **Table 2.1 & 2.2** below.

2. **Details on estimation and computation of air emissions (such as Nitrogen Oxides, Sulphur Oxides, Carbon Monoxide, Hydrocarbons, VOCs, etc.) resulting from flaring, DG sets, combustion, etc. in all project phases.**

   Reply: The estimation and computation of air emissions from DG set and Flare has done. From the estimations, it can be concluded that no adverse impact is envisaged.

I. Emission from DG Set

The emission dispersion rate from the DG sets has been estimated using SCREEN view model, (This SCREEN View model is developed and supported by US EPA. It can model scenarios with simple or complex terrain, with or without building downwash and give results at discrete or automated distances and can remove the need for more complicated modeling, saving time and resources). The required input for the SCREEN view to run the model are provided in the **Table 2.1.** The emission rate has been calculated based on the emission factors (*Source: section 3.3 of Stationary Internal Combustion Sources, AP-42, US EPA* *https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s03.pdf*).

Table 2.1: Emission Quantity

S. No.	DG set Capacity	Stack height (m)	Emission Rate (g/s)					Gas Exit Temp (° C)	Stack Dia. (mm)	Gas Exit Flow rate (m^3/min)
			PM_{10}	SO_2	NOx	VOC	CO			
1.	2500 KVA (1865 HP)	9.4	0.16	0.094	4.69	0.16	1.29	517	203	339.4
2.	2250 KVA (1600 HP)	6.3	0.14	0.08	4.03	0.16	1.10	511.4	203	170.3
3.	1000 KVA (750 HP)	10	0.066	0.037	1.88	0.066	0.52	465.8	203	444.2
4.	550 KVA (410 HP)	4.7	0.11	0.10	1.55	0.13	0.35	543.1	203	83.5

The maximum predicted concentration of the pollutants (for all the DG sets) and distances to the maximum concentration from the source are given in the **Table 2.2.**

Table- 2.2 Maximum Concentration and Distance from the Source

S. No	Parameters	Maximum concentration (ug/m^3)	Distance to maximum concentration from the source (m)	Standard Limit CPCB, 2000[1] (ug/m^3)
DG set with Capacity 1865 HP				
1.	PM_{10}	3.5	246	200
2.	SO_2	2.1		80
3.	NO_x	102		80
4.	VOC	3.5		-
5.	CO	28		2000
DG set with Capacity 1600 HP				
6.	PM_{10}	5.52	206	200
7.	SO_2	3.15		80
8.	NO_x	155		80
9.	VOC	6.31		-
10.	CO	43.37		2000
DG set with Capacity 750 HP				
11.	PM_{10}	3.01	192	200
12.	SO_2	1.66		80
13.	NO_x	85.67		80
14.	VOC	3.01		-
15.	CO	23.70		2000
DG set with Capacity 410 HP				
16.	PM_{10}	20	33	200
17.	SO_2	18		80
18.	NO_x	280		80
19.	VOC	28		-
20.	CO	63		2000

The maximum concentration is predicted at a distance of 246 m downwind from the source. At some locations, nitrogen dioxide exceeds the limit within the radius of 1000 m from the source. However, beyond 1000 m, all the parameters are within the safe limit as per the Environmental Standards for Ambient Air, Automobiles, Fuels, Industries and Noise, CPCB, 2000.

As stated earlier, the project location is 72 km (approx.) far from the nearest land (i.e. Diu coast). So, no impact envisaged by these emissions to the nearby locality (receptors). However, during construction suitable control measures will be taken, such as installation of high efficiency generator sets which will be provided with adequate stack height and modern emission control equipment.

[1] [1] *Environmental Standards for Ambient Air, Automobiles, Fuels, Industries and Noise, CPCB, 2000.*

For DG set 1865 HP

(i) PM10

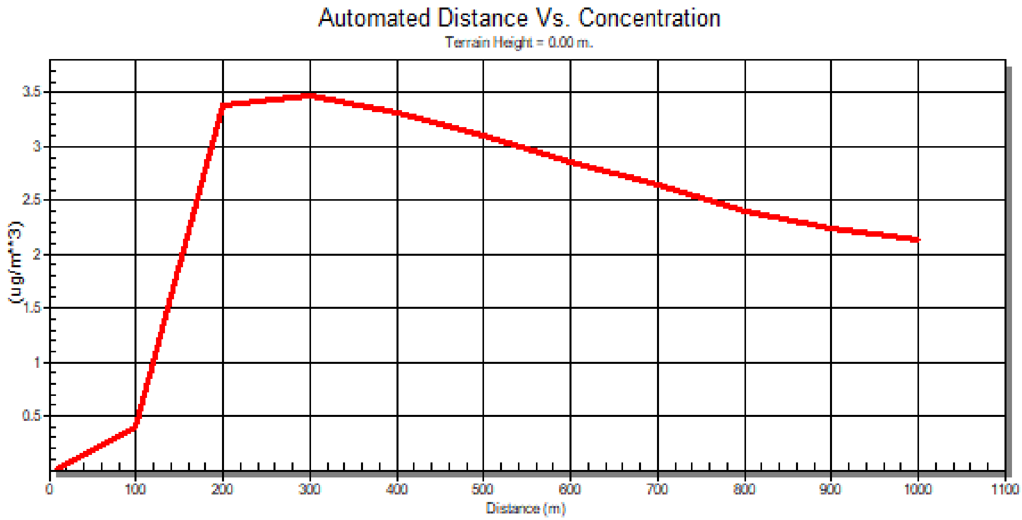


Figure 2.1: Concentration vs Distance – PM10

(ii) SO_2

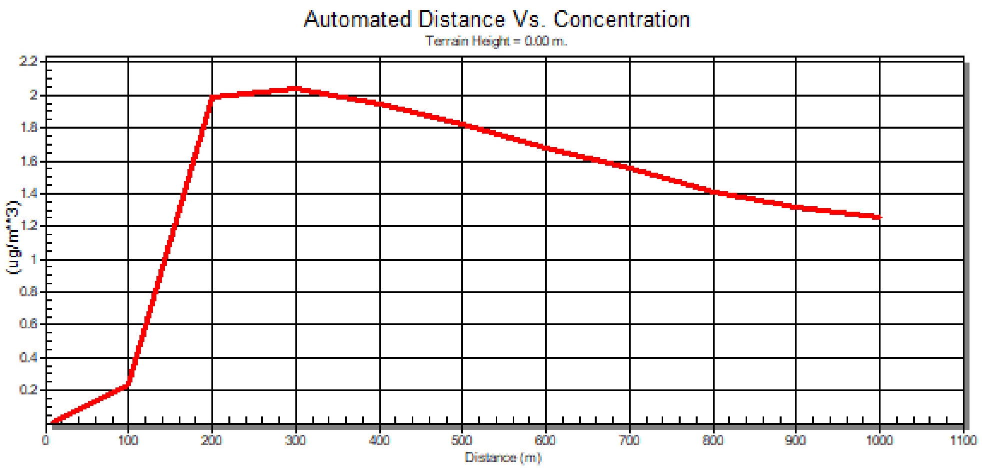


Figure 2.2: Concentration vs Distance – SO_2

(iii) NO_x

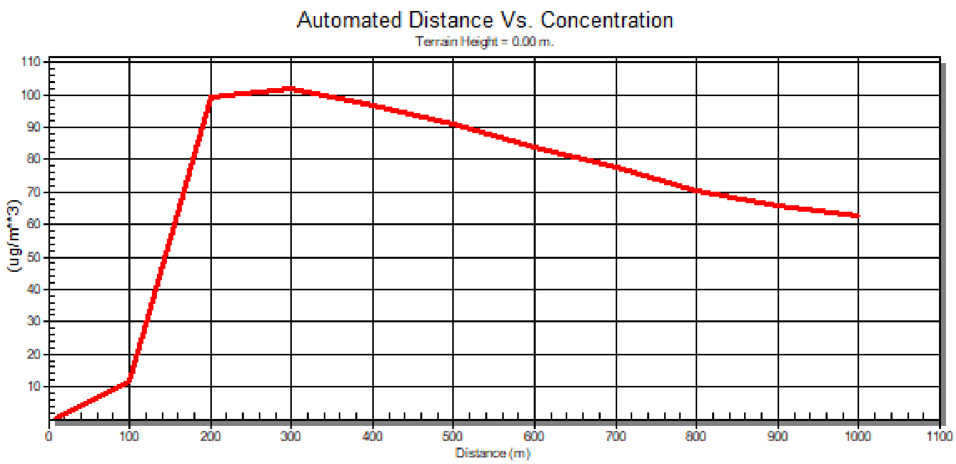


Figure 2.3: Concentration vs Distance – NO_x

(iv) VOC

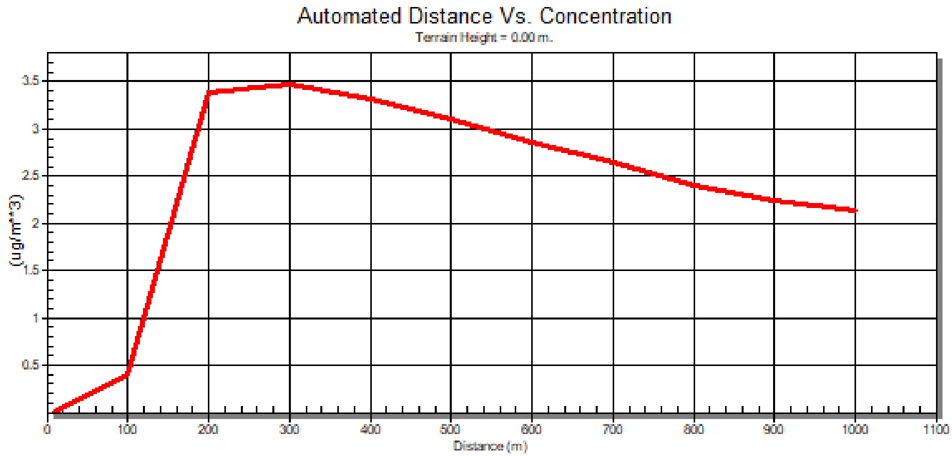


Figure 2.4: Concentration vs Distance – VOC

(v) CO

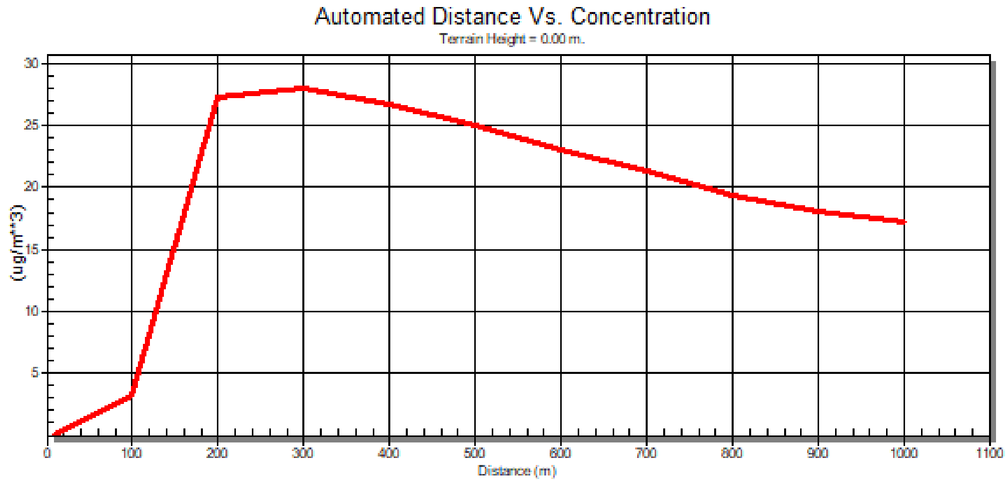


Figure 2.5: Concentration vs Distance – CO

For DG set 1600 HP

(i) PM10

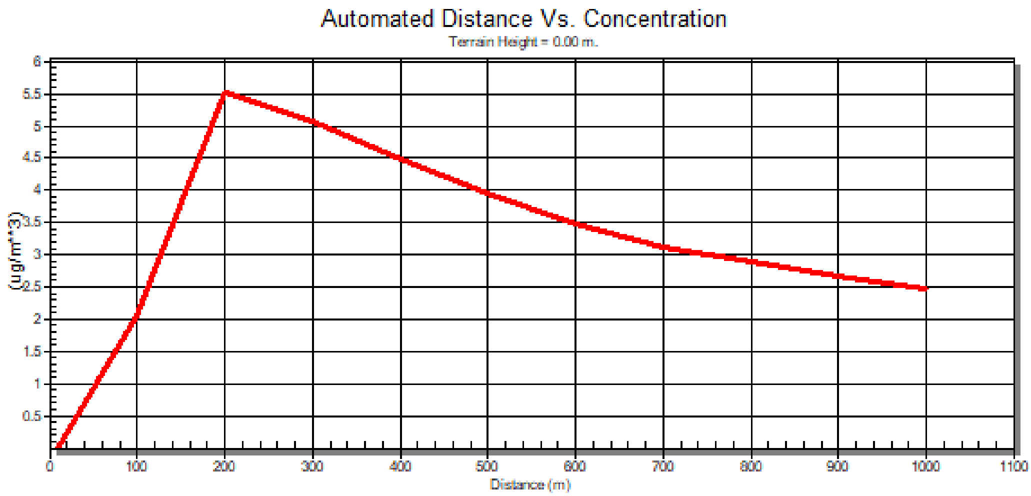
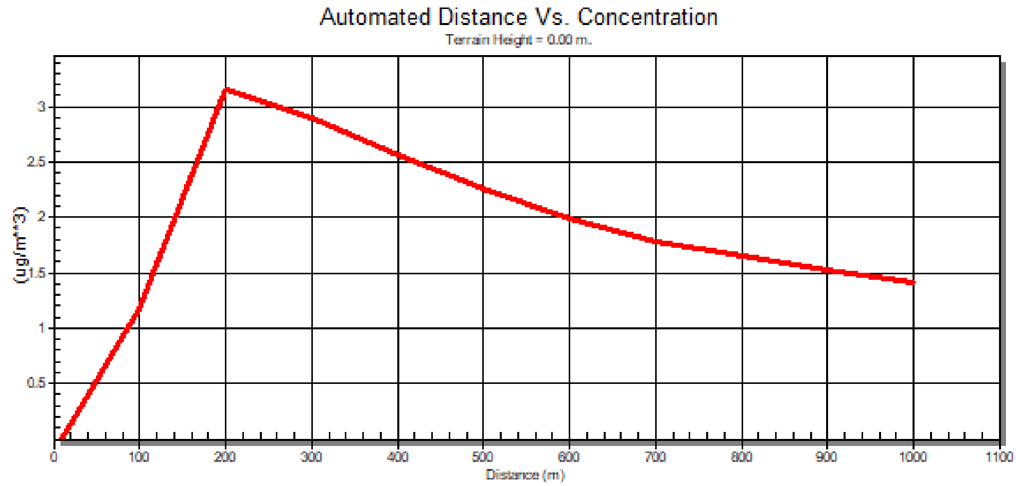


Figure 2.6: Concentration vs Distance – PM10

(ii) SO_2



(iii) Figure 2.7: Concentration vs Distance – SO_2

(iv) NO_x

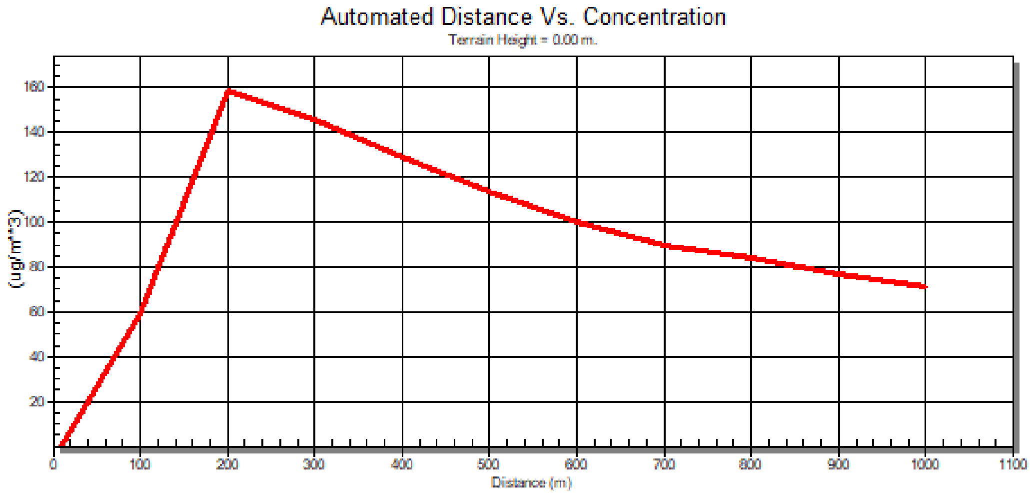


Figure 2.8: Concentration vs Distance – NO_x

(v) VOC

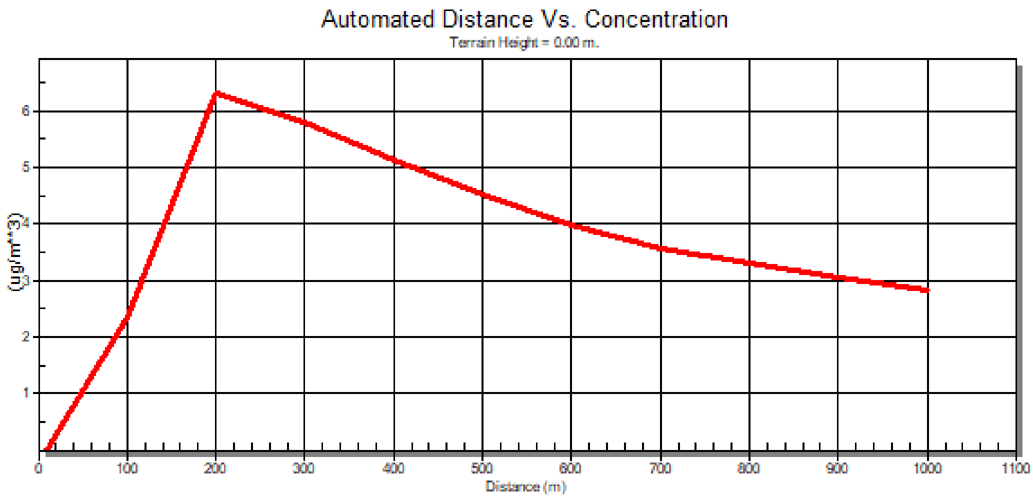


Figure 2.9: Concentration vs Distance – VOC

(vi) CO

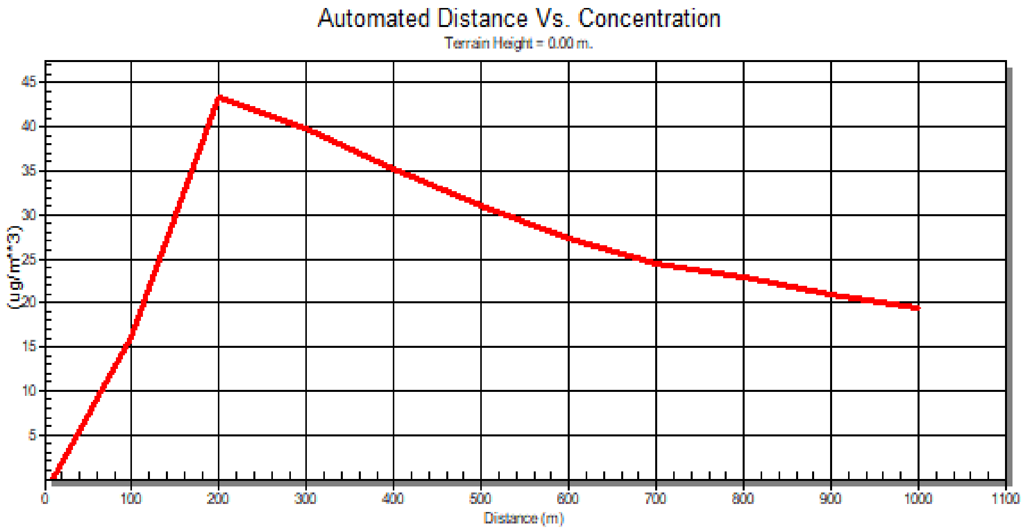


Figure 2.10: Concentration vs Distance – CO

For DG set 750 HP

(i) PM10

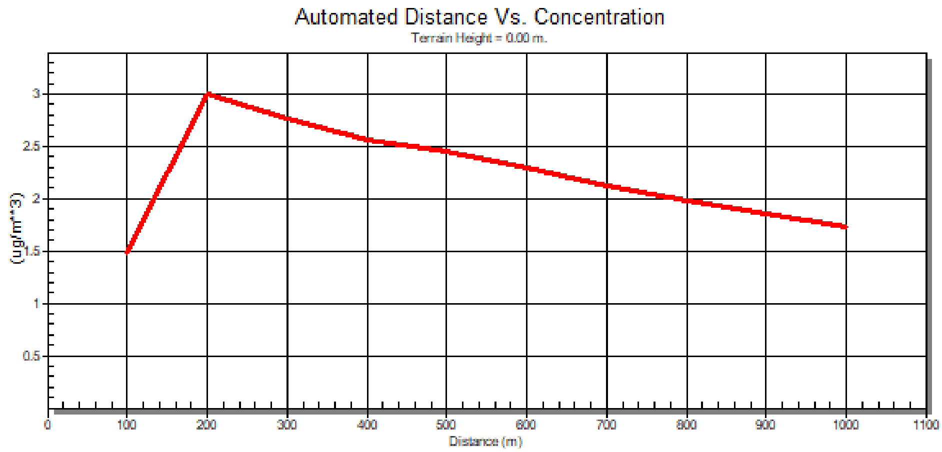


Figure 2.11: Concentration vs Distance – PM10

(ii) SO_2

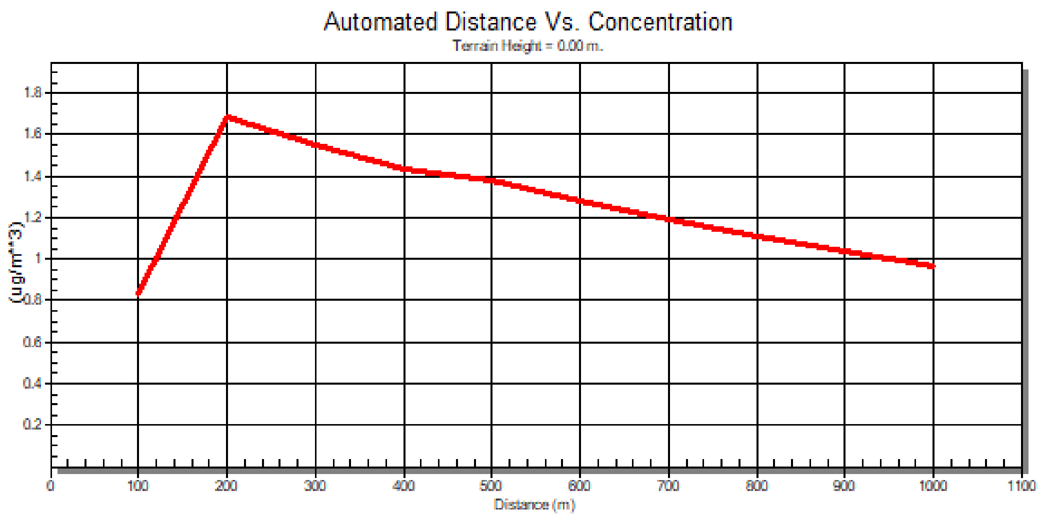


Figure 2.12: Concentration vs Distance – SO_2

(iii) NO_x

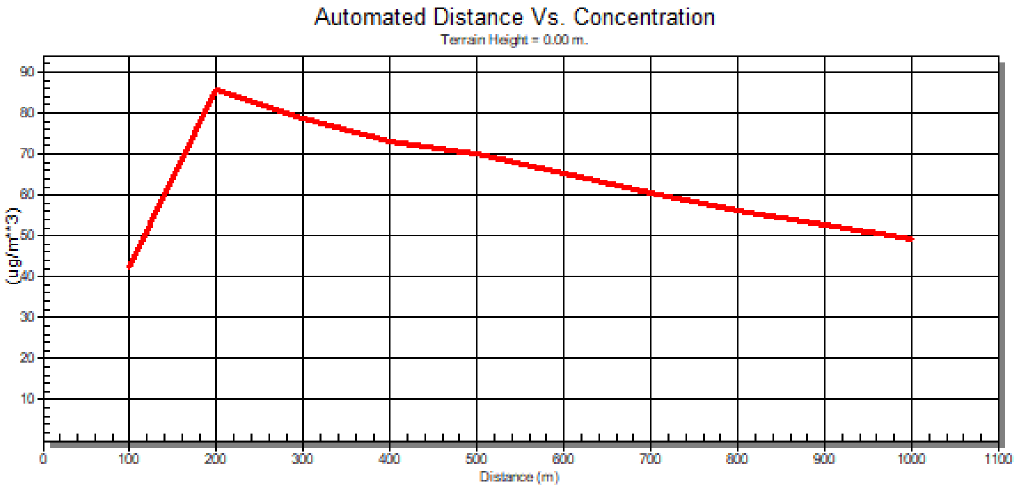


Figure 2.13: Concentration vs Distance – NO_x

(iv) VOC

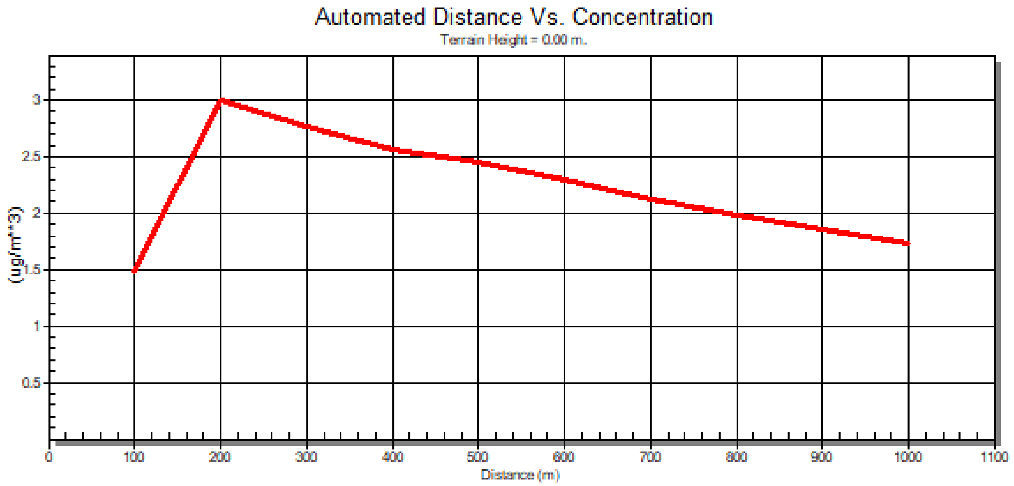


Figure 2.14: Concentration vs Distance – VOC

(v) CO

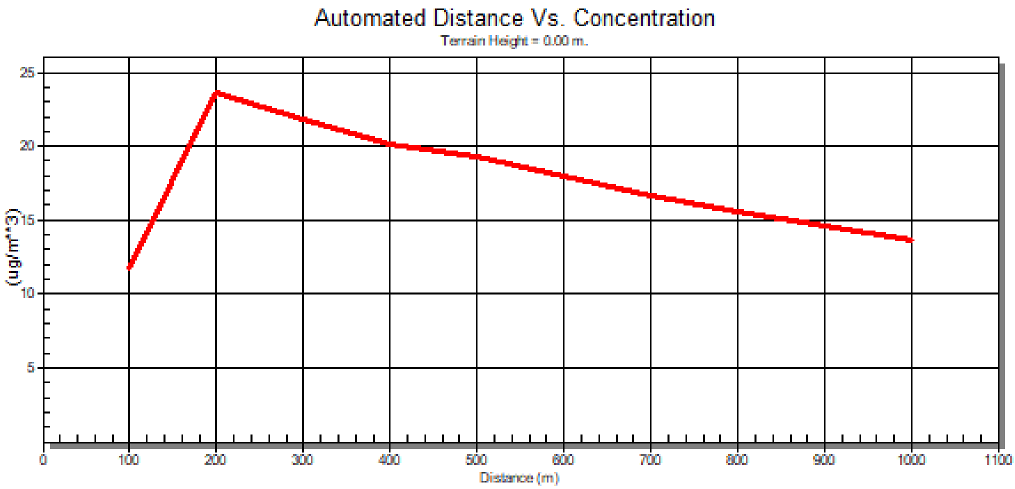


Figure 2.15: Concentration vs Distance – CO

For DG set 410 HP

(i) PM10

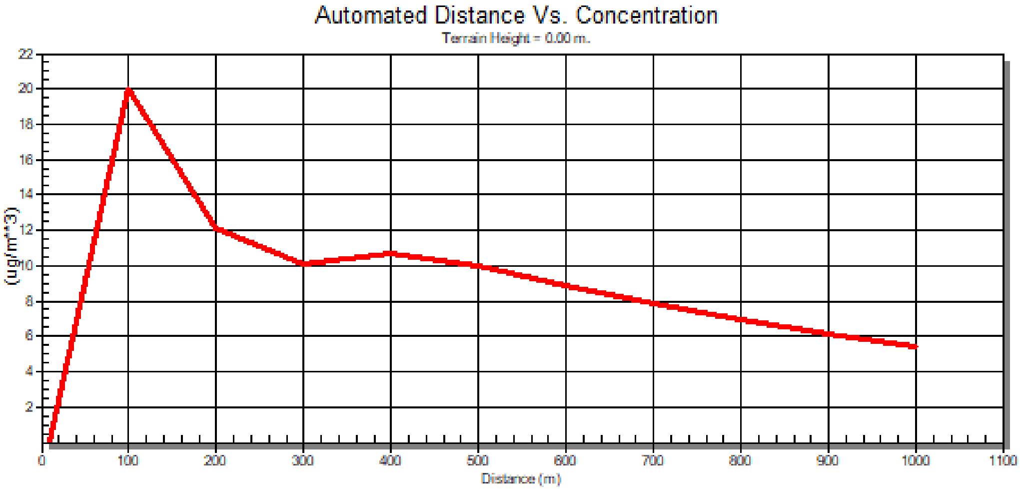


Figure 2.16: Concentration vs Distance – PM10

(ii) SO_2

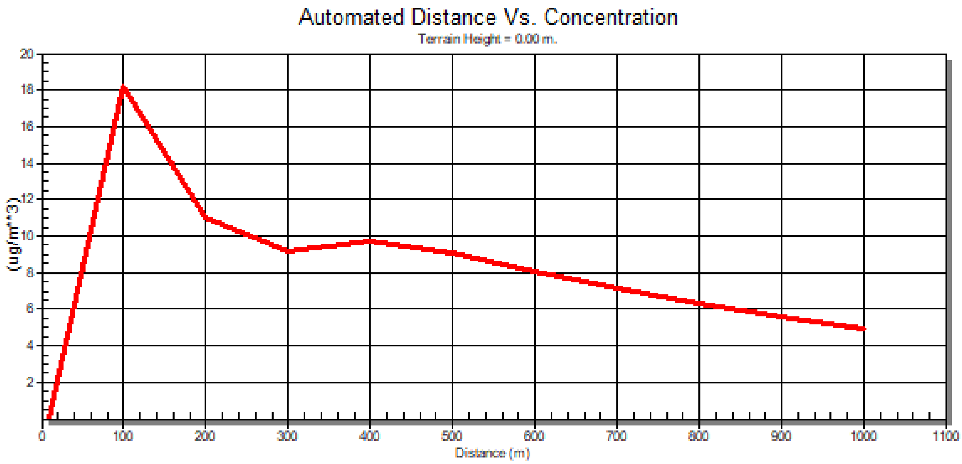


Figure 2.17: Concentration vs Distance – SO_2

(iii) NO_x

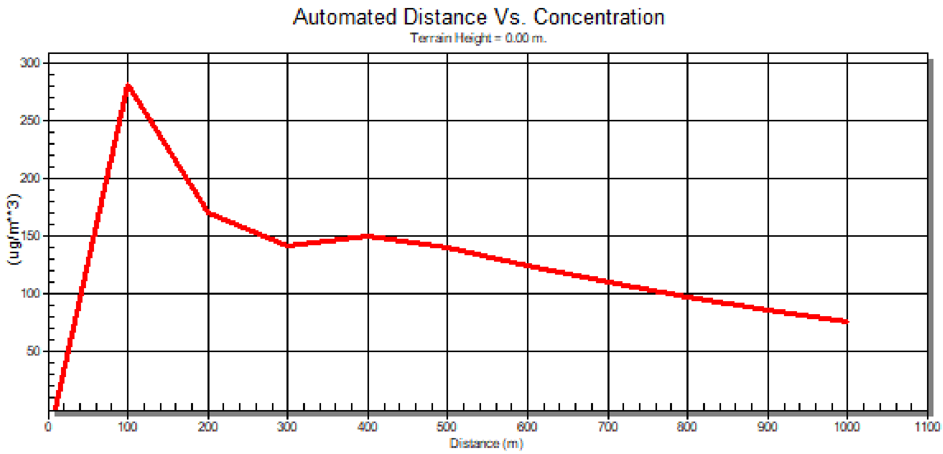


Figure 2.18: Concentration vs Distance – NO_x

(iv) VOC

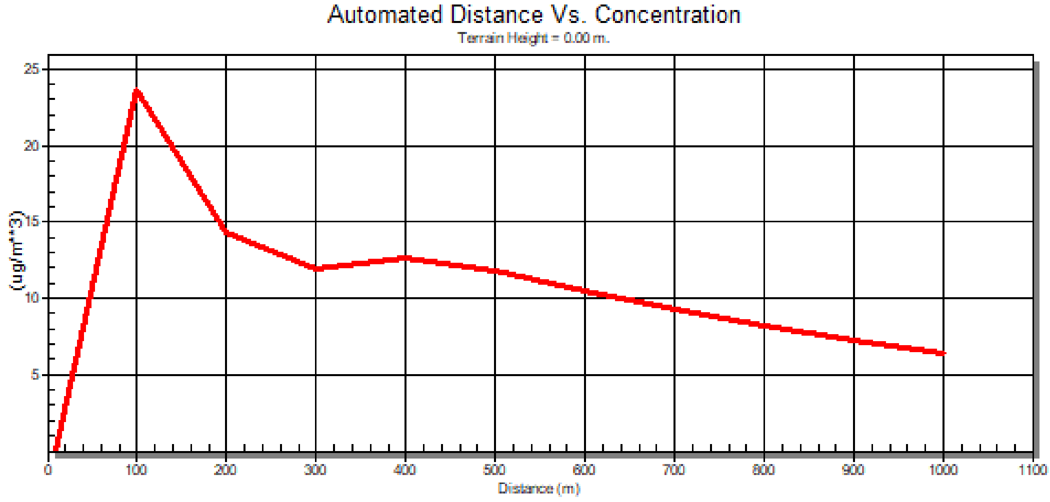


Figure 2.19: Concentration vs Distance – VOC

(v) CO

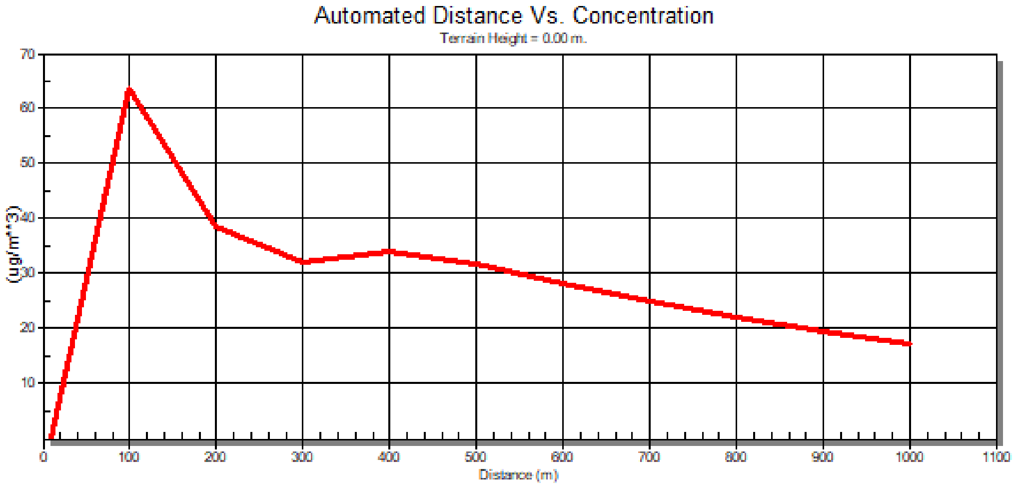


Figure 2.20: Concentration vs Distance – CO

II. Air Quality Prediction using SCREEN View - Flare

The prediction of pollutants to be emitted from the flare was done using US EPA model SCREEN View 4.0.1 version developed by lakes Environmental as the model include flares as a source option.

Source

The maximum gas flow rate for the present study is 12 MMSCF/day and, the flaring will take place 24 hours per day for upto 9 days per well (Test flaring of gas per well is expected to be done for about 4 days per zone. There are 2 zones to be tested per well. Hence up to 9 days.). The details of the gas composition are given in **Table 2.3.**

Table 2.3: Gas Composition

Gas Comp. (% Vol)	
Methane	77.09
Ethane	7.77
Propane	4.92
I Butane	2.81
N-Butane	2.04
I-Pentane	1.54
N-Pentane	1.25
CO_2	0.30
N_2	2.28

Model Inputs

Emission Rate

Emission rate for the present study has been calculated based on the emission factors. *(source: section 13.5 of AP-42, US EPA)*. The emission factors are provided for the following four (04) pollutants as given in the **Table 2.4.**

Table 2.4: Emission Factor[2]

S.No	Pollutants	Emission Factor (lb/ 10^6 Btu)
1.	Total hydrocarbons (THC)	0.335
2.	Carbon monoxide (CO)	0.37
3.	Volatile organic compounds	0.66
4.	Nitrogen oxides (NOx)	0.068

(Source: AP 42, Emission Factor, Fifth Edition, Volume I, Industrial Flares, US EPA; These factors apply to well operated ground flares & elevated flare achieving at least 95% destruction)

Based on the emission factor for pollutants as provided in the above table and gas flow rate, the emission rate for each pollutant has been computed and summarized in the below **Table 2.5.**

Table 2.5: Emission Rate

S.No	Components	Emission Rate (g/s)
1.	Total hydrocarbons (THC)	22.15
2.	Carbon monoxide (CO)	24.48
3.	Volatile organic compounds	43.65
4.	Nitrogen oxides (NOx)	4.49

Total Heat Release rate

The heat release rate as given in the **Table 2.6** was used, as it is one of the key factor for the model to run.

Table 2.6: Thermal Equivalents for Fuel (Gas)

Type of Fuel	Heating value
	Kcal/m3
Gas (composition as provided above)	10,652

[2] *Compilation of Air Pollutant Emissions Factors (AP-42), Chapter 13, Miscellaneous Sources Section 13.5, Industrial Flares, 2018.*

In case of elevated flaring, the minimum stack height shall be 30 m, Height of the stack shall be such that the max. GLC never exceeds the prescribed ambient air quality limit (*source: Environmental Standards for Ambient Air, Automobiles, Fuels, Industries and Noise, CPCB, 2000*).

Results

The output from the modelling study is in the form of a graph showing ground level concentration versus distances as presented in **Figure 2.21** to **Figure 2.24**. The maximum concentration is predicted at a distance of 1,239 m downwind from the source. The maximum predicted concentration of pollutants are given in the **Table 2.7** along with standard limit. As per the National Institute for Occupational Safety and Health's (NIOSH) maximum recommended safe methane concentration for workers during the 8-hr period is 1000 ppm.

Table 2.7: Dispersion Modelling Results

S. No	Compound	Maximum Predicted concentration (µg/m^3)	Standard Limits[3] (µg/m^3)
1.	Total Hydrocarbon (THC)	13.5	-
2.	Carbon monoxide (CO)	15	5000 (8-hr std)
3.	Volatile Organic Compounds (VOC)	26	-
4.	Nitrogen Oxides (NOx)	3	120 (24 -hr)

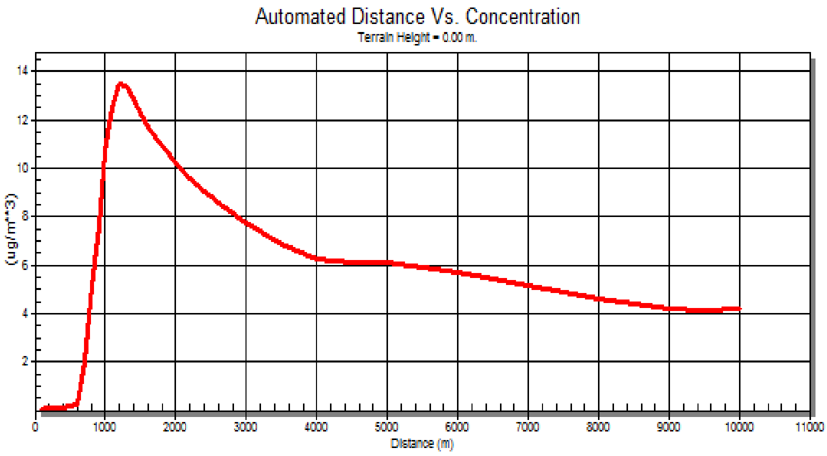


Figure 2.21: Maximum Concentration Predicted for THC

[3] *Environmental Standards for Ambient Air, Automobiles, Fuels, Industries and Noise, CPCB, 2000.*

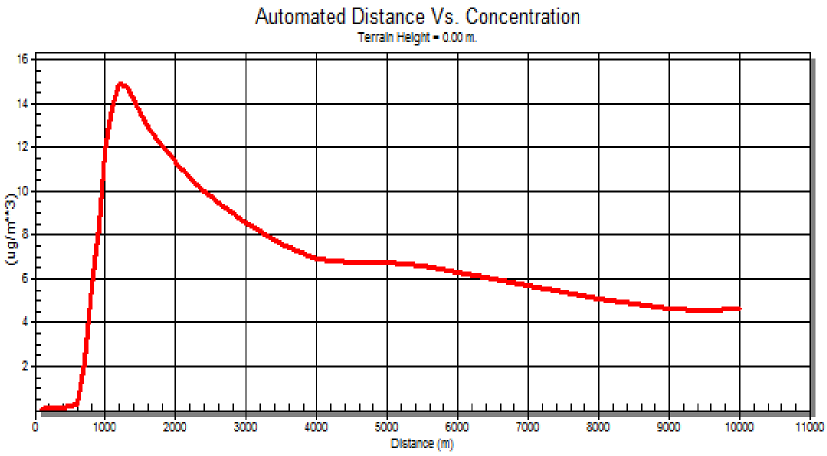


Figure 2.22: Maximum Concentration Predicted for CO

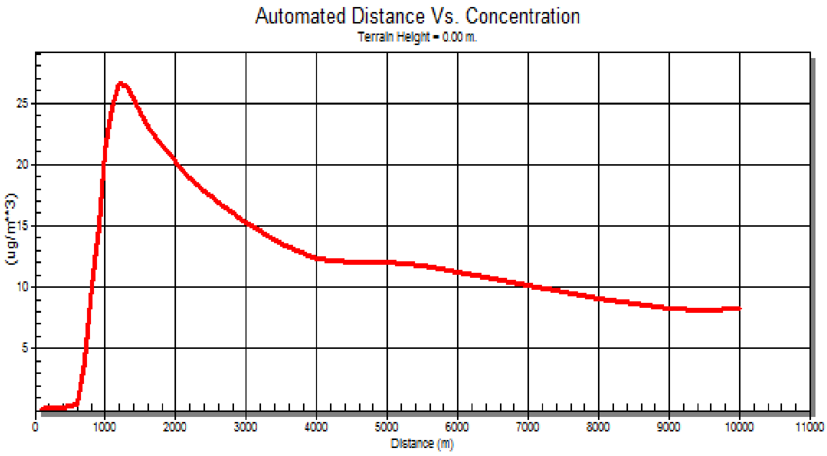


Figure 2.23: Maximum Concentration Predicted for VOC

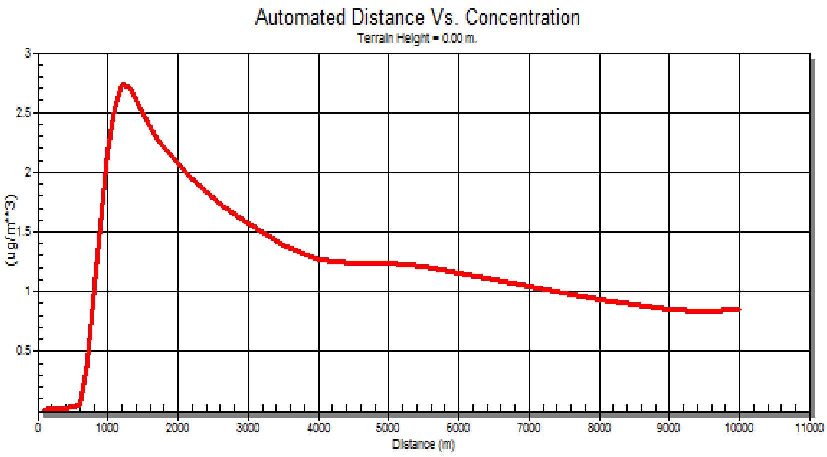


Figure 2.24: Maximum Concentration Predicted for NOx

3. Baseline data collection within 1km of each development well, in respect of oil/metal/hydrocarbon content in the surface water and sediments.

3.1 Marine Environment Monitoring

Water and sediment quality sampling were carried out in B-9, B-7 and BRC blocks of the cluster offshore fields in the Mumbai Offshore Basin. The samples collected were sent to laboratory for the analysis.

Marine Sampling Methodology

A survey vessel scrutinized by Offshore Defense Advisory Group (ODAG) was hired for offshore sampling. The vessel was well-equipped with Global Positioning System (GPS) and Radar for accurate positioning, radio communication and satellite telephone for communication. The survey vessel was cruised to the sampling locations according to the given geographical coordinates, i.e., latitude and longitude of the sampling locations. The documents for Vessel, ODAG clearance, Credentials of personnel involved in sample collection, Inspection pictures and details of GPS Data Log are annexed as **Annexure- I** ***(enclosed with this report).***

3.1.1 Sea Water Monitoring

Sampling Location

The following criterias were considered for selection of marine water sampling location:

- The sampling locations were selected within 1 km around the well head platform,
- The sampling locations were selected to describe the marine environmental conditions of the entire project area (block).
- Sampling location were selected on the basis of hydrodynamics, range of depths , sea currents etc.

The marine water sampling locations are given in **Figure 3.1** and **Figure 3.2** *(denotes the sampling location selected within 1 km of the well head platform location)* below. It highlights the five (5) water sampling locations along with the route followed by the survey vessel in the Mumbai Offshore Basin during the sampling and sampling location map with well head platforms (including 1 km buffer), respectively. **Table 3.1** depicts the coordinates of sampling locations, along with the sampling depths. **Table 3.2** shows the wellhead platform coordinates. All the five samples *(surface and bottom)* from the 3 designated O&G fields in the project location were collected during the study period i.e. in May 2018.

Table 3.1: Coordinates of Sea Water (SW) Sampling Location

S. No.	Sampling Location	Location Code	Latitude (N)	Longitude (E)	Sea Water Sampling Depth	
					Bottom (m)	Surface (m)
1.	B9-1	SW1	20° 08’.23.0”	71°21’.42.7”	33	3
2.	B9-2	SW2	20° 05’.37.8”	71°26’.23.6”	33	3
3.	B9-3	SW3	20° 01’.48.1”	71°27’.34.4”	34	3
4.	B7	SW4	19° 58’.34.4”	71°11’.37.1”	42	3
5.	BRC	SW5	19° 53’.36.4”	71°10’.54.2”	39	3

Table 3.2 Well-Head Platform Coordinates

S. No.	Field	Latitude	Longitude	Remarks
B-9 Field				
1.	Well-Head Platform 1 (B-9-1 area)	20°08'19.09"N	71°21'59.92"E	Surface location of 4 wells
2.	Well-Head Platform 2 (B-9-3 area)	20°05’39.63"N	71°26’0.92" E	Surface location of 3 wells
B-7 Field				
3.	Well-Head Platform 3	19°58’45.33" N	71°08'39.4" E	Surface location of 3 wells in B-7
BRC Field				
4.	Well-Head Platform 4	19°53’05.911”N	71°10'51.267" E	Surface location of 2 well in BRC

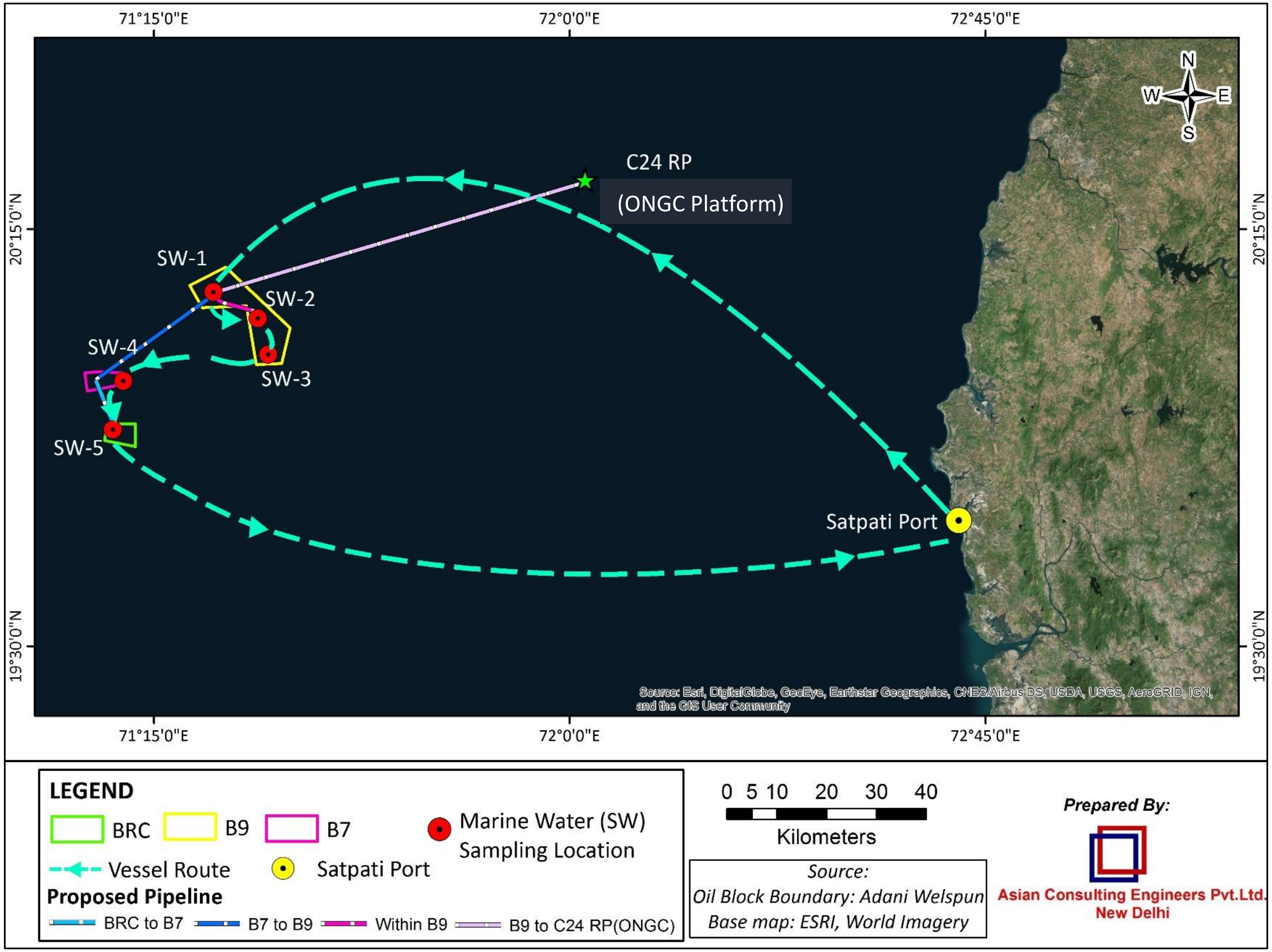


Figure 3.1: Sea Water Sampling Locations with Vessel Route

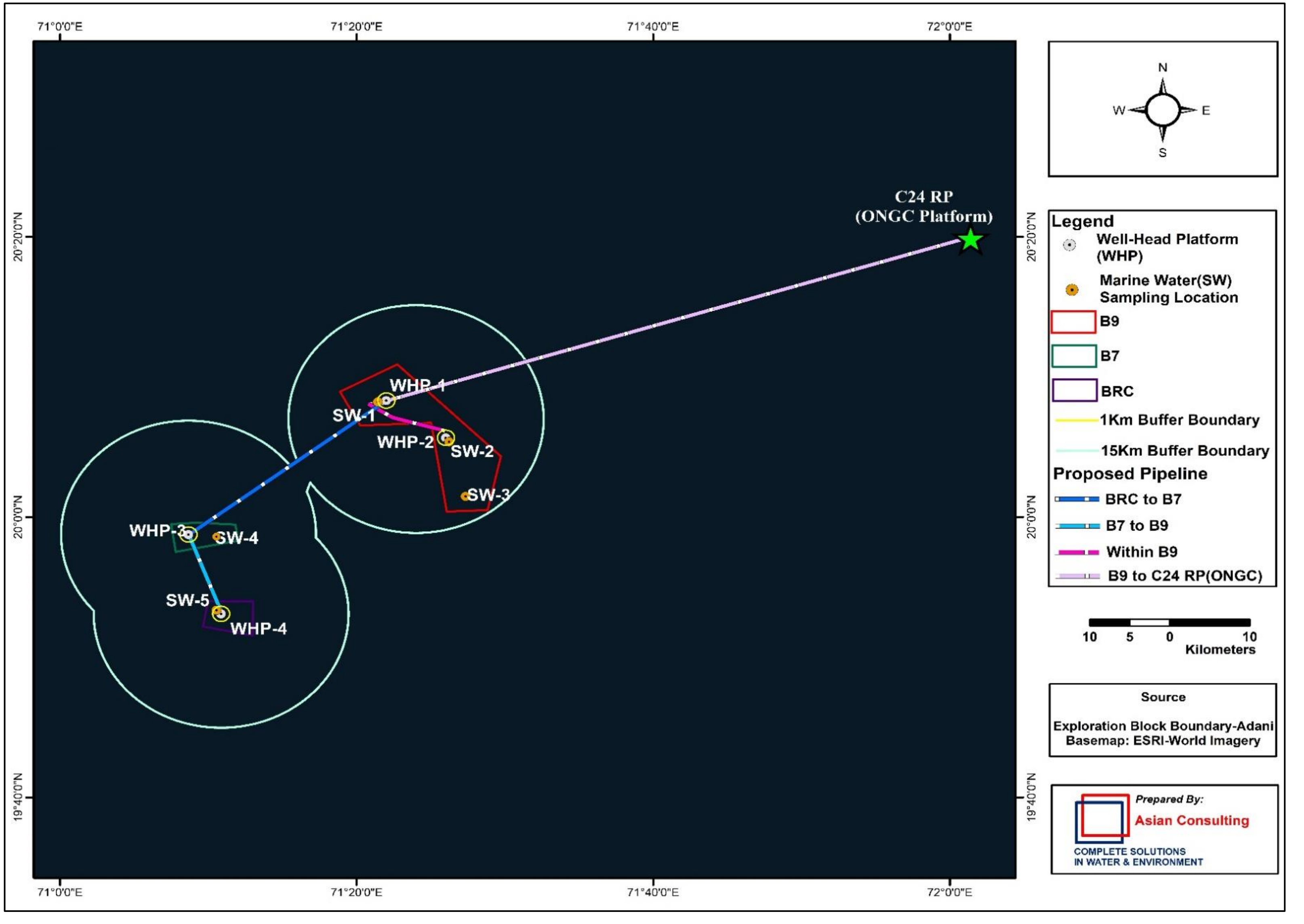


Figure 3.2: Sea Water Sampling Locations within Study Area

Sea Water Sampling Method

The sea water (SW) samples were collected from two (2) levels in the sea (**Table 3.1**, above), i.e., at the surface and bottom levels using a Niskin Sampler of 5 liters capacity. The depth levels are as follows:

a. **Sample 1** – 3 m below the surface
b. **Sample 2 –** 33-42 m (approx.) below the sea surface and 10-15 meters above the sea bed.

The quantity of sea water collected for different parameters along with the techniques for the preservation of the samples are depicted in **Table 3.3**.

Table 3.3: Preservation of Water Samples

S. No.	Sample Particulars	Sample Quantity	Preservation
1.	Dissolved Oxygen	300 ml in glass stoppered bottle/ BOD Bottle.	2 ml Wrinkler's A (Manganous Sulfate) followed by 2 ml Wrinkler's B (Alkaline Iodide Sodium Azide Solution).
2.	Oil and Grease	1 Liter in wide mouth glass bottle.	Adjust pH to <2 with conc. Sulfuric Acid or Hydrochloric Acid.
3.	Metals	1 Liter in PP container.	Adjust pH to <2 with conc. Nitric Acid.
4.	Other Physio-chemical Parameters	2 Liter in PP/PE container.	Refrigerate at 4°C.
5.	Primary productivity	300 ml in glass stoppered bottle/ BOD Bottle.	• Fixed immediately after sampling as described for Dissolved Oxygen preservation. • Keep in dark or wrapped in Aluminum wrapper and then refrigerate.
6.	Chlorophyll	1 Liter sample in wide mount PP Bottle.	----------------------------
7.	Phytoplankton	1 Liter water sample filtered through plankton net.	Preserved with Lugol's Iodine immediately and stored in dark.
8.	Zooplanktons	1 Liter water sample filtered through plankton net.	Preserved with Formalin immediately.


Marine Water Sampling using NISKIN Sampler

Marine Water Sampling using NISKIN Sampler

Sample Storage for Lab Analysis

On-Site Preservation of Samples

Photo Plate 3.1: Marine Water Sampling

(Source: ACE Survey).

Analysis Method:

The water samples were analyzed by the methods suggested by Grasshoff (1983) and APHA (1985). All the colorimetric estimations were done using double beam spectrophotometer (Genesys 10 UV Thermo Spectronic). pH was measured using a pH meter MK-Vl. The results of the marine water quality analysis are tabulated in **Table 3.4**.

Table 3.4: Marine Water Quality Analysis*

S. No.	Parameters	Unit	DL	SW1 at B9-1		SW2 at B9-2		SW3 at B9-3		SW4 at B7		SW5 at BRC	
				Surface	Bottom	Surface	Bottom	Surface	Bottom	Surface	Bottom	Surface	Bottom
1.	**pH**	--	--	8.1	8.0	8.1	8.1	8.2	8.2	8.2	8.2	8.2	8.2
2.	**Electrical Conductivity**	mS/cm	--	47,760	46,540	45,240	44,930	45,370	45,540	44,930	44,380	45,190	44,980
3.	**Dissolved Oxygen**	mg/L	--	5.2	5	4.8	4.6	4.9	4.5	4.6	4.4	4.8	4.6
4.	**Salinity**	Ppt	--	35.3	35.1	32.8	36.1	35.3	34.6	35.6	36.1	35.9	36.9
5.	**Total Dissolved Solids**	mg/L	--	31,856	31,744	30,244	32,158	31,622	30,122	33,258	34,692	33,568	35,482
6.	**Total Suspended Solids**	mg/L	--	77	86	45	93	77	70	91	91	63	86
7.	**Total Hardness as $CaCO_3$**	mg/L	--	8,000	10,000	8,000	10,000	10,000	8,000	8,400	9,000	8,600	8,000
8.	**BOD (@ 27°C, 3 Days)**	mg/L	2	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
9.	**Total Alkalinity as $CaCO_3$**	mg/L	--	126	130	130	126	130	132	130	130	130	128
10.	**Nitrates as NO^{3-}**	mg/L	0.44	0.80	0.73	0.64	BDL	0.68	BDL	BDL	BDL	BDL	BDL
11.	**Sulphate as SO_4^{2-}**	mg/L	--	3,520	3,570	3,298	3,454	2,444	2,474	2,514	3,536	3,312	2,590
12.	**Oil & Grease**	mg/L	10	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
13.	**Chlorides as Cl**	mg/L	--	19,563	19,420	18,135	19,991	19,563	19,134	19,706	19,991	19,848	20,419
14.	**Residual Free Chlorine**	mg/L	0.1	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
15.	**Iron as Fe**	mg/L	0.06	BDL	BDL	BDL	BDL	BDL	BDL	0.41	BDL	3.1	0.9
16.	**Manganese as Mn**	mg/L	0.03	BDL	BDL	BDL	BDL	0.05	BDL	BDL	0.09	BDL	0.07
17.	**Cadmium as Cd**	mg/L	0.015	BDL	BDL	BDL	BDL	BDL	BDL	BDL	0.015	BDL	BDL
18.	**Chromium as $Cr^{6}+$**	mg/L	0.01	BDL	BDL	BDL	0.01	BDL	BDL	BDL	BDL	BDL	BDL
19.	**Lead as Pb**	mg/L	0.01	BDL	BDL	BDL	BDL	BDL	BDL	0.02	0.01	BDL	BDL
20.	**Nickel as Ni**	mg/L	0.02	BDL	BDL	BDL	BDL	BDL	BDL	0.02	BDL	BDL	BDL
21.	**Zinc as Zn**	mg/L	0.02	BDL	BDL	BDL	BDL	0.3	0.05	BDL	0.03	0.02	0.02
22.	**Mercury as Hg**	mg/L	0.0015	BDL	BDL	0.0015	BDL	0.0027	BDL	0.0023	0.0016	BDL	0.0015
23.	**Arsenic as As**	mg/L	0.03	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL

(Source: Primary data generated for this project-Ultra Tech Laboratories, Thane).

***Note:**

1. **DL – Detection Limit**
2. **BDL – Below Detection Limit**

Results of Sea Water Monitoring

The observed pH value in the study region during the period of study is in the range of 8.0 to 8.2. The changes in pH are marginal as expected for natural marine waters sustaining low primary productivity. The total hardness (as $CaCO_3$) in all the water sample lies in the range of 8000 to 10000 mg/L. The value of alkalinity (as $CaCO_3$) was in the range of 126 to 132 mg/l. The dissolved oxygen ranges from 4.4 mg/l to 5.2 mg/l.

The concentrations of Chloride in all the sample were in the range of 18135 to 20419 mg/L. The contents of oil & grease in all sample was below detectable limit (BDL) in all the sampling locations. The BOD levels in all water samples was found to be below detection limit (BDL) wherein the detection limit for BOD is 2 mg/L.

It has been observed from the laboratory analysis that residual free chlorine, $Cr^{6}+$, and As were below detection limits in all the water samples. Whereas, there has been observed a slight detection in few samples in regard to the concentration of lead, nickel, zinc and mercury.

3.1.2 Sea Sediments Monitoring

Sampling Location

The following criterias were considered for selection of sea sediment sampling location:

- The sampling locations were selected within 1 km around the well head platform and one,
- The sampling locations were selected to describe the sea bed characteristics of the entire project area (block).
- Sampling location were selected on the basis of hydrodynamics, range of depths , sea currents etc.

The marine sediment sampling locations are given in **Figure 3.3** and **Figure 3.4** *(denotes the sampling location selected within 1 km of the well head platform location)* below. It highlights the five (5) water sampling locations along with the route followed by the survey vessel in the Mumbai Offshore Basin during the sampling and sampling location map with well head platforms (including 1 km buffer), respectively. **Table 3.5** depicts the coordinates of sampling locations, along with the sampling depths. All the five samples were collected from the 3 designated O&G fields in the project location.

Table 3.5: Coordinates of Sea Sediment (SS) Sampling Location

S. No	Sampling Location	Location Code	Latitude (N)	Longitude (E)	Sea Sediment Sampling Depth (m)
1.	B9-1	SS1	20° 08’.23.0”	71°21’.42.7”	40
2.	B9-2	SS2	20° 05’.37.8”	71°26’.23.6”	40
3.	B9-3	SS3	20° 01’.48.1”	71°27’.34.4”	40
4.	B7	SS4	19° 58’.34.4”	71°11’.37.1”	58
5.	BRC	SS5	19° 53’.36.4”	71°10’.54.2”	54

Sea Sediments Sampling Methodology

Sea sediment samples were collected using a Van-Veen Grab Sampler. It is an instrument to sample sediment in water environments. The grab was lowered vertically from the stationary boat until it touched the bottom. Sediment samples were collected and preserved for sediment texture analysis and physico-chemical analysis. The quantity of SS collected along with the techniques for the preservation of the samples are depicted in **Table 3.6**. **Photo Plate 3.2** shows the collection of sediment from the various sampling locations.

Table 3.6: Preservation of Sediment Samples

S. No	Sample Particulars	Sample Quantity	Preservation
1.	**Marine Sediment**	1 kg in leakage protective bag.	Refrigerate at 4°C
2.	**Marine Benthos**	Sediment collected from sea bed sieved through 500-micron test sieve stored in 125 ml wide mouth PP bottle	Preserved with Formalin immediately

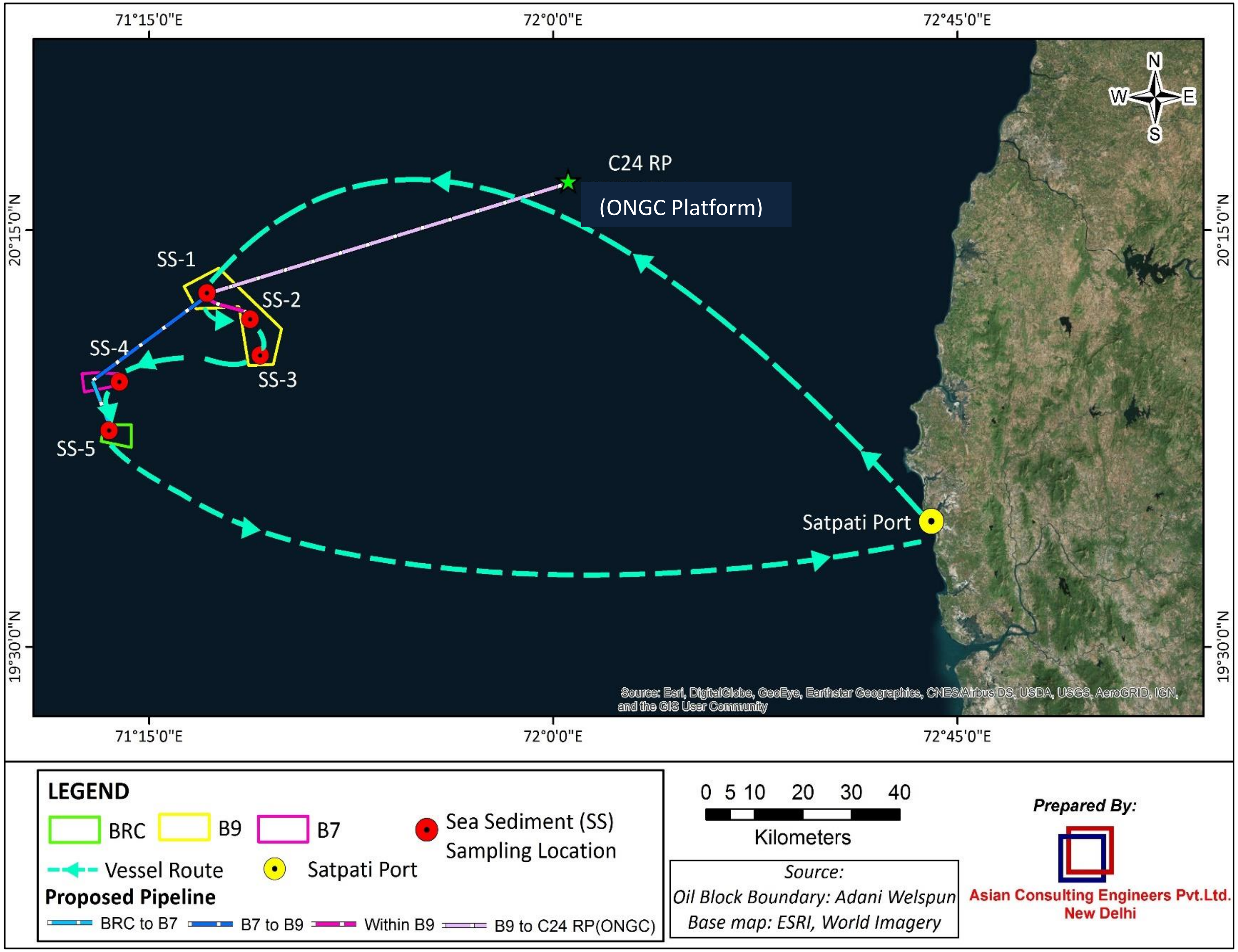


Figure 3.3: Sea Sediment (SS) Sampling Location & Vessel Route

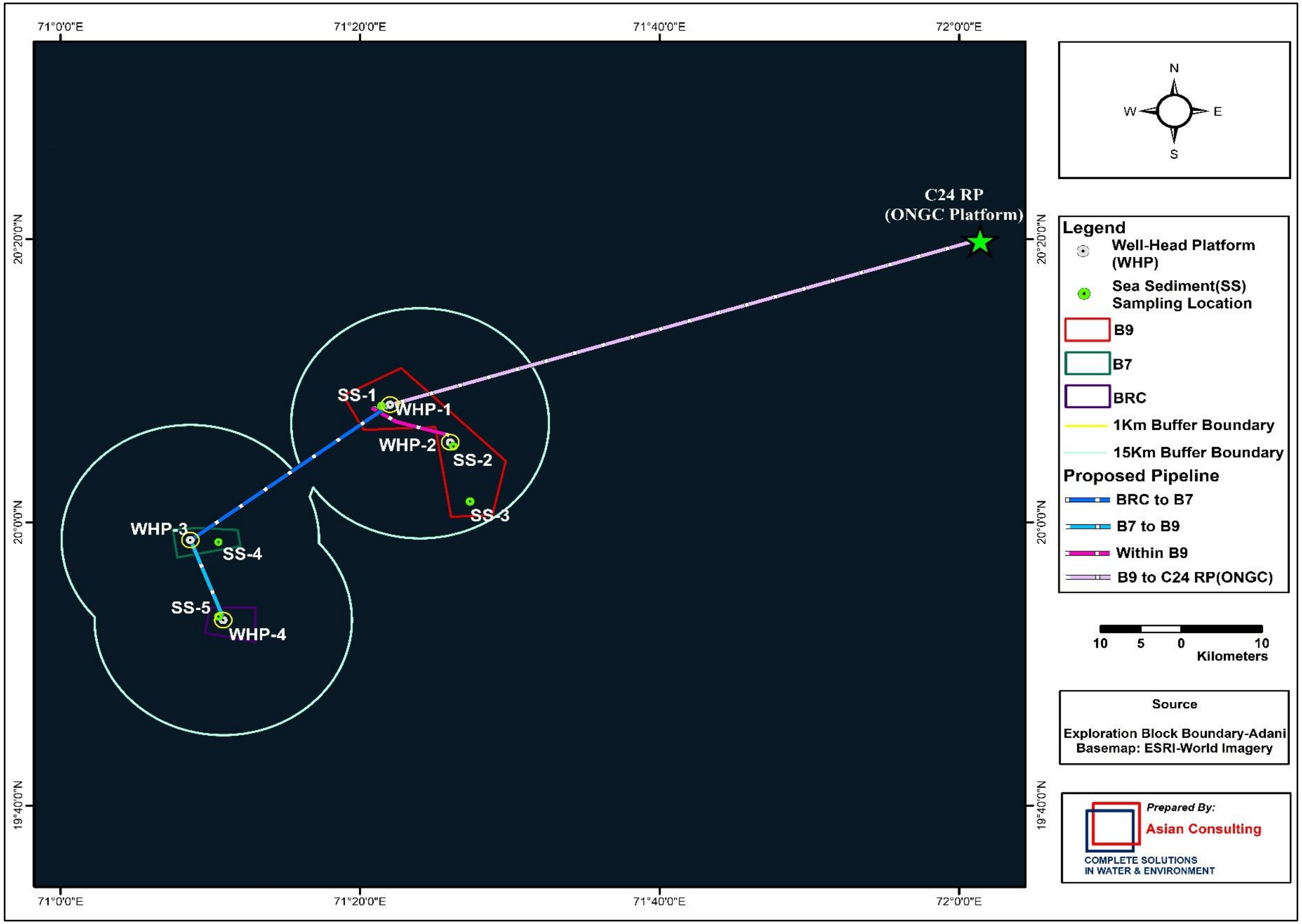


Figure 3.4: Sea Sediment (SS) Sampling Location & Vessel within Study Area

Photo Plate 3.2: Sediment Sample Collection from Mumbai Offshore Basin.

(Source: ACE Survey).

Analysis Method:

The sea sediments were processed and analyzed by the USEPA methods [3050 B (SW-846), 7000B, 7061A, 9071B etc.]. Heavy metals are analysed by flame atomic absorption spectroscopy method. pH was analysed by IS: 2720 (part 26), 1987. The results of the marine sediment quality analysis are tabulated in **Table 3.7** below.

Table 3.7: Marine Sediment Quality Analysis

S. No.	Parameters	Unit	DL	SS1 at B9-1	SS2 at B9-2	SS3 at B9-3	SS4 at B7	SS5 at BRC
1.	pH (1:2.5: Sediment: Water Extract)	--	--	8.4	8.4	8.2	8.5	8.5
2.	Oil and Grease	%	--	0.7	0.5	0.4	0.4	0.1
3.	Nitrate as Nitrogen	mg/kg	2	3	BDL	BDL	BDL	3
4.	Total Kjeldahl Nitrogen	mg/kg	--	520	431	440	403	528
5.	Hexavalent Chromium as Cr(VI)	mg/kg	0.01	BDL	BDL	BDL	BDL	BDL
6.	Polyaromatic Hydrocarbon	mg/kg	--	0.82	1.12	0.85	0.23	0.61
7.	Arsenic as As	mg/kg	2	4.2	2.9	BDL	BDL	2.3
8.	Cadmium as Cd	mg/kg	2	BDL	BDL	BDL	BDL	BDL
9.	Iron as Fe	mg/kg	0.44	49,318	56,797	39,243	46,442	48,497
10.	Lead as Pb	mg/kg	--	7	6	6	6	5
11.	Mercury as As	mg/kg	2	BDL	BDL	3	BDL	BDL
12.	Zinc as Zn	mg/kg	--	69	65	68	65	60

(Source: Primary data generated for this project- Ultra Tech laboratories).

Note: DL- Detection Limit

BDL-Below Detection Limit

Results of Sea Sediment Monitoring

Oil and grease ranges from 0.1 to 0.7, Nitrite as Nitrogen found as 3 mg/kg at location SS1 & SS5 while in the rest of the locations, the values are below detection limits. The Total Kjeldahl Nitrogen ranges from 403 mg/kg to 528 mg/kg.

The hexavalent chromium is found below the detection limit at all the locations.

Among the heavy metals, iron varied from 39,243 mg/kg to 56,797 mg/kg and lead from 5 mg/kg to 7 mg/kg, zinc showed variation of 60 mg/kg to 69 mg/kg, cadmium was found below detection limit and arsenic varied from 2.3 mg/kg to 4.2 mg/kg.

Among the exchangeable nutrient fractions of nitrogen, nitrate was found 3 mg/kg at location SS1 & SS5, at rest of the location it is below detection limit i.e. 2. The polyaromatic compounds are found ranges from 0.23 mg/kg to 1.12 mg/kg, the amount of PAH is observed low.

3.1.3 Biological Analysis

To monitor biological characteristics of the marine environment, diversity of phytoplankton, zooplankton and benthic organisms were assessed.

Sampling Location

Ecological sampling was carried out to conduct the analysis. **Photo Plate 3.4** shows few glimpses of the ecological sampling done in the B-9 Cluster block, monitoring locations. Sea water samples have been collected for analyzing primary productivity, phytoplankton and zooplankton diversity from the locations as mentioned in **Table 3.1** above. For analyzing diversity of the benthos, sediments have been collected from five locations as mentioned in **Table 3.5**, above.

Photo Plate 3.4: Ecological Sample Collection from Mumbai Offshore Basin

(Source: ACE Survey).

a) Chlorophyll Analysis

Chlorophyll concentration is the result of the conversion of inorganic nutrients into living biomass and acts as an indicator of the health and productivity of the estuarine ecosystem. However, high levels of chlorophyll for a long duration indicate poor water quality while low levels often suggest good quality.

Methodology

Chlorophyll was estimated following the methods published by UNESCO (1966). A known volume of water sample was filtered through Millipore GF/C filter paper with $MgCO_3$ suspension. Subsequently the filters were extracted with 90% acetone, centrifuged for 10 minutes at 5000 rpm. The extinction of the supernatant solution was measured using spectrophotometer against a reference cell containing 90% acetone at 665, 645 and 630 nm and the concentration was calculated using standard equations.

b) Phytoplankton, Zooplankton and Benthos Analysis

Analysis Methodology

Phytoplankton: Thirty (30) liters of surface water was filtered through phytoplankton net of 20μm mesh size made of bolting silk. The filtrate was preserved in 3% neutralized formaldehyde/Lugol's iodine solution. Quantitative analysis was done employing Sedgewick-Rafter counting cell. Species identification was done using a Leica DM 2000 LED light microscope.

Enumeration by Sedgewick-Rafter Counting Cell: The planktonic microalgae filtered from 30 liters of surface water were made up to a 10 ml volume concentrate. One (1) ml of this sample was transferred to the Sedgewick-Rafter Counting Cell (*volume of this chamber is 1ml*). The number of microalgae present in all the thousand grids in the Sedgewick-Rafter Counting Cell was calculated. Counting was repeated for three times and an average was taken. The total number of planktonic algal species present in one (1) liter of water sample was calculated using the formula:

$$N = \frac{n \times v}{V}$$

Where, N = No. of planktonic algae per liter of water filtered

n = Average no. of planktonic algae in one (1) ml of sample

v = Volume of plankton concentrates in ml

V = Total volume of water filtered in liter

Identification of phytoplankton: Phytoplankton groups were identified based on standard keys (*Allen and Cupp, 1935;Venkataraman, 1939;Cupp, 1943;Subrahmanyan, 1946;Hustedt, 1955;Desikachary, 1959;Hendey, 1964;Simonsen, 1974;Gopinathan, 1984; Jin Dexiang et al., 1985;Desikachary and Sreelatha, 1989;Hallegraeff et al., 1995; Tomas et al., 1997*).

***Zooplankton**:* Samples were collected from the surface waters along each location by horizontal surface towing of plankton net (Bongo Net, mouth area $0.25m^2$, mesh size 200µm) for 10 minutes. Samples were collected in 250 ml plastic bottles and preserved in 4% buffered formaldehyde which was later used for qualitative and quantitative analysis following Goswami and Padmavathi (1996)[4].

Zooplankton biomass is expressed as $ml/1000m^3$ by using the formula as given below:

Biomass = Displacement Volume/ Volume of Water Filtered

The zooplankton taxa were sorted from the whole sample or from an aliquot (50%) using a Folsom Splitter (*Sell and Evans, 1982*) and counted under a stereomicroscope. The zooplankton was primarily sorted to the major taxonomic groups according to the standard identification manuals (Newell and Newell, 1973; Todd and Laverack, 1991). The keys employed include the works of Todd *et al.*, (1996), Wilson (1932), Davis (1955), Kasthurirangan (1963), Krishnapillai (1986) and Wickstead (1965).

The abundance is expressed as 'ind / 1000 m^3' using the formula:

Abundance (ind/1000 m^3) = No. of individuals of the particular taxa /volume of water filtered

Benthos: The sediment for analysis of benthos, both macro and meiofauna has been collected using a standard Van-Veen Grab Sampler, with an area of 0.2 m^2 (*Anastasio Eleftheriou and Alasdair McIntyre, 2005; Holme and McIntyre, 1971*).

***Macro-benthos*:** Macrobenthos were separated by sieving the sediment through 0.5 mm sieve. The organisms retained in the sieve are considered as macrobenthos. The entire macrobenthic specimen were picked out from the sediment and sorted out. Before sieving, samples were treated with Rose Bengal in order to enhance the colour contrast of the organisms. Identification was carried out for major groups such as polychaetes and molluscs. The standard as well as published references were used for identification of different macrofauna (*Fauvel, 1953 and other published works*). Identification was followed by count of the individuals per species for polychaetes and molluscs and group for rest of the organisms.

[4]*Goswami and Padmavathi, 1996. Zooplankton Production, Composition and Diversity in the Coastal Waters of Goa. Indian J. Mar. Sci., 25(91-97).*

***Meio-benthos*:** For the analysis of meiofauna, graduated glass corer, 30 cm long with an inner diameter of 2.5 cm was used to sub sample meiofauna from $0.2m^2$ Van-Veen grab haul. The corer was inserted into the undisturbed sediment, to a depth of 4 cm and samples were transferred into labeled plastic containers containing 5% neutral formalin. The sediment containing the meiofauna was stained with Rose Bengal biological stain (0.1 g in 100 ml of distilled water). The organisms were separated and enumerated using a binocular microscope and preserved in 4 % neutral formalin (*Giere, 2008*). The numerical abundance of organisms was extrapolated in to no./$10cm^2$. The standard as well as published references were used for identification of the different meiofauna (*Giere, 2008*).

Analysis Results

The location-wise abundance of the various species of phytoplankton, zoo planktons, benthic meio and the chlorophyll productivity are given in **Table 3.8** The abundance of phytoplankton genera, zooplankton genera and benthic phylum are separately shown in **Table 3.9**, **Table 3.10** and in **Table 3.11** respectively**.** The graphical analysis of the abundance of the species, location-wise, is shown in **Figure 3.5**.

Table 3.8: Marine Biological Environment Analysis (S-Surface, B-Bottom)

S. No.	Parameters	Unit	SW1 at B9-1		SW2 at B9-2		SW3 at B9-3		SW4 at B7		SW5 at BRC	
			S	B	S	B	S	B	S	B	S	B
1.	**Chlorophyll-a**	mg/m^3	2.72	2.85	2.91	2.81	3.04	1.91	3.49	1.95	3.81	3.39
2.	**Primary Productivity-*Gross***	$mgC/m^3/d$	680	--	640	--	490	--	600	--	490	--
3.	**Primary Productivity-*Net***	$mgC/m^3/d$	190	--	120	--	150	--	70	--	80	--
4.	**Phyto-plankton**	No./ml	200	100	191	76	190	181	288	247	932	520
5.	**Zooplankton**	No./ m^3	1214	--	1478	--	1044	--	1211	--	1183	--
6.	**Benthic Meio**	No./m^2	--	25	--	19	--	12	--	60	--	17

(Source: Primary data generated for this project-Ultra Tech Laboratories, Thane).

Table 3.9: Abundance of Phyto-plankton Species (S-Surface, B-Bottom)

Speciation of Phytoplankton Species Observed												Total No. of Samples	Total No. of Occurrence.
S. No.	Phytoplankton Genera	SW-1		SW-2		SW-3		SW-4		SW-5			
		S	B	S	B	S	B	S	B	S	B		
1	Amphiprora	-	-	+	+	-	+	-	+	-	-	10	4
2	Amphora	+	-	-	-	-	-	-	-	-	-	10	1
3	Anabaena	-	-	-	-	-	-	-	-	-	+	10	1
4	Asterionellopsis	+	-	+	+	-	+	+	+	-	-	10	6
5	Ceratium	-	+	-	-	-	-	+	-	-	+	10	3
6	Chaetoceros	+	+	+	+	+	+	+	+	-	-	10	8
7	Corethron	-	-	-	-	+	-	+	+	-	-	10	3
8	Cyclotella	-	-	-	-	-	-	-	-	+	+	10	2
9	Cylindrotheca	+	+	+	+	+	+	+	+	+	+	10	10
10	Diploneis	+	+	-	-	-	-	-	-	-	-	10	2
11	Ditylum	+	+	+	+	-	+	+	+	-	-	10	7
12	Gonyaulax	-	-	+	-	-	-	+	+	+	-	10	4
13	Guinardia	+	+	+	+	+	+	+	+	+	+	10	10
14	Gymnodinium	+	+	+	-	+	+	+	+	-	-	10	7
15	Gyrodinium	-	-	-	+	+	+	+	+	+	+	10	7
16	Gyrosisma	-	-	-	-	-	-	-	-	-	+	10	1
17	Leptocylindrus	-	-	-	-	-	-	+	-	+	+	10	3
18	Lithodesmium	-	-	-	-	+	+	+	-	-	-	10	3
19	Mallomonas	-	-	-	-	-	-	-	-	+	-	10	1
20	Melosira	+	-	-	-	-	-	-	-	-	-	10	1
21	Navicula	-	+	-	-	-	-	+	-	+	+	10	4
22	Nitzschia	+	+	-	+	+	+	+	-	-	+	10	7
23	0dontella	+	+	+	+	+	+	+	+	+	+	10	10
24	Peridinium	-	-	-	-	+	-	+	-	+	+	10	4
25	Pleurosigma	+	+	+	+	+	-	+	+	+	+	10	9
26	Prorocentrum	-	+	-	-	+	-	-	-	+	-	10	3
27	Protooeridinium	-	+	-	-	+	-	+	-	+	-	10	4
28	Pseudo-nilzschia	+	+	+	+	+	+	+	+	+	+	10	10
29	Rhizosolenia	-	+	+	-	+	+	+	+	+	+	10	8
30	Skeletonema	+	-	+	-	+	+	-	-	+	+	10	6
31	Surirella	-	+	+	-	+	+	-	-	+	+	10	6
32	Thalassionema	+	+	+	+	+	-	+	+	+	-	10	8
33	Thalassiosira	+	+	+	+	+	+	+	+	+	+	10	10
34	Thalassiothrix	-	-	-	-	-	-	-	-	+	-	10	1
35	Triceratium	-	-	-	+	+	+	-	-	-	-	10	3
36	Trichodesmium	-	-	-	-	-	-	-	-	-	+	10	1

(Source: Primary data generated for this project-Ultra Tech Laboratories).

Table 3.10: Abundance of Zooplankton Species

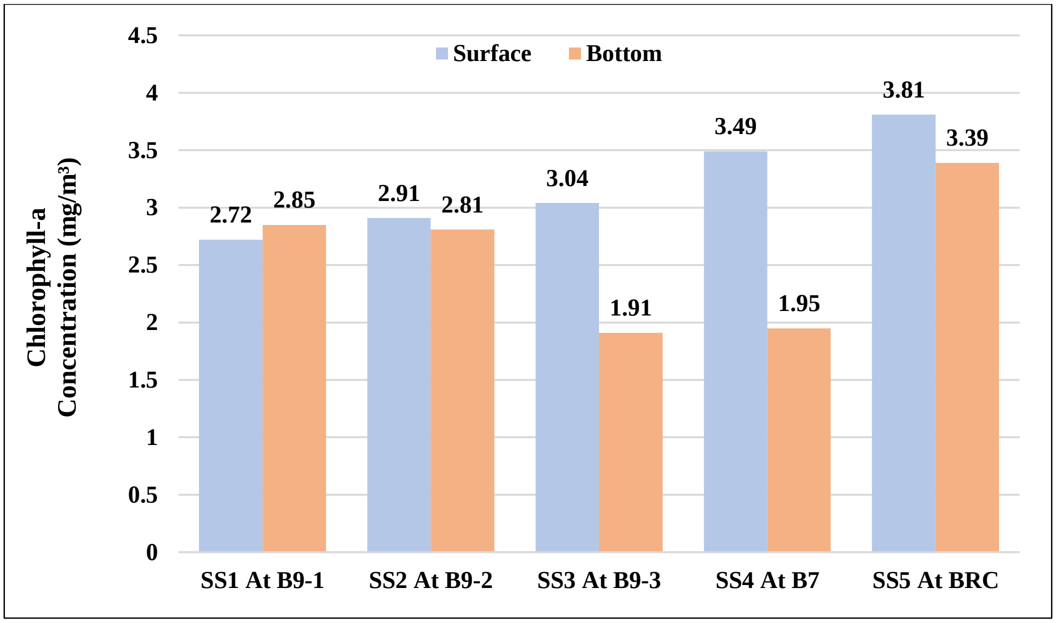
Speciation of Zooplankton Species Observed (Surface)							Total No. of Samples	Total No. of Occurrence
S. No.	Zooplankton Genera	SW-1	SW-2	SW-3	SW-4	SW-5		
1.	*Acetes* sp.	+	+	+	+	-	5	4
2.	Amphioods	+	-	-	+	-	5	2
3.	Chaetognaths	+	+	+	-	-	5	3
4.	Copepods	+	+	+	+	+	5	5
5.	Ctenonhores	-	-	-	+	-	5	1
6.	Decapod larvae	+	+	+	+	+	5	5
7.	Foraminiferans	+	-	-	-	-	5	1
8.	Fish Eggs	-	-	+	-	-	5	1
9.	Fish Larvae	+	+	+	+	+	5	5
10.	Gastropods	+	+	+	+	+	5	5
11.	Isopods	+	+	+	+	+	5	5
12.	Lamellibranchs	+	+	+	+	+	5	5
13.	Lucifer sp.	+	+	+	+	+	5	5
14.	Medusae	+	-	+	+	+	5	4
15.	Mysids	+	+	+	+	-	5	4
16.	Polychaetes	+	+	-	+	-	5	3
17.	Siphonophores	+	+	-	+	-	5	3

(Source: Primary data generated for this project-Ultra Tech Laboratories, Thane).

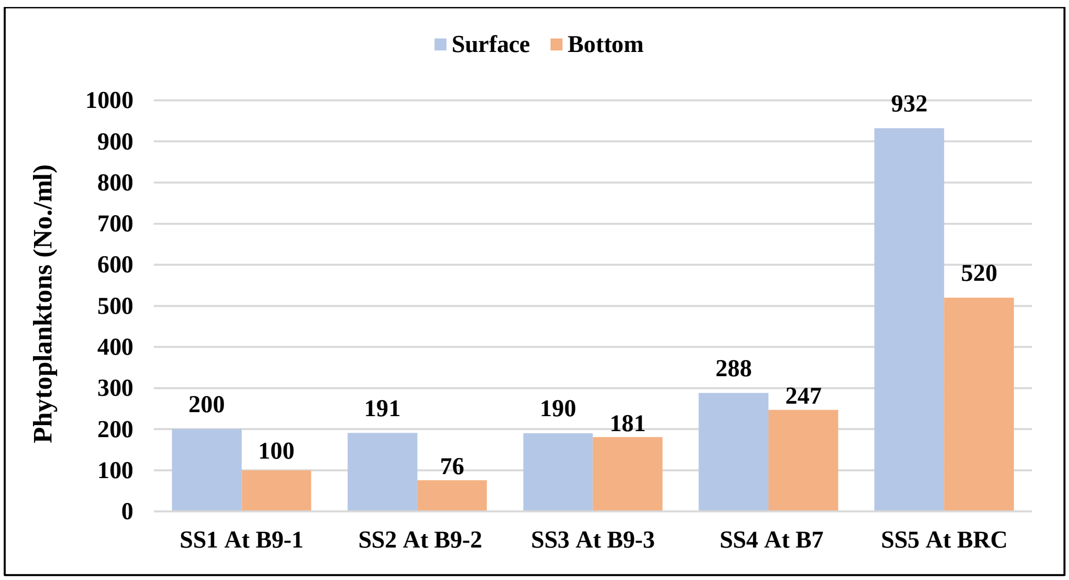
Table 3.11: Abundance of Benthic Species (Bottom)

Speciation of Benthos Species Observed								Total No. of Samples	Total No. of Occurrence
Sl. No.	Phylum	Groups	SS-1	SS-2	SS-3	SS-4	SS-5		
1.	Mollusca	Gastropoda	-	-	+	-	+	5	2
2.	Mollusca	Pelecypods	+	+	-	-	+	5	3
3.	Annelida	Polychaetes	+	+	-	+	-	5	3
4.	Sipuncula	Sipunculid	-	-	-	-	+	5	1
5.	Arthropoda	Isoooda	-	-	-	+	-	5	1
6.	Arthropoda	Brachyura	+	-	+	-	-	5	2
7.	Arthropoda	Sergestids	+	-	-	+	-	5	2
8.	Chordata	Fish larvae	+	-	-	-	-	5	1
9.	Nemetrea	Nemetrea	-	-	-	-	+	5	1

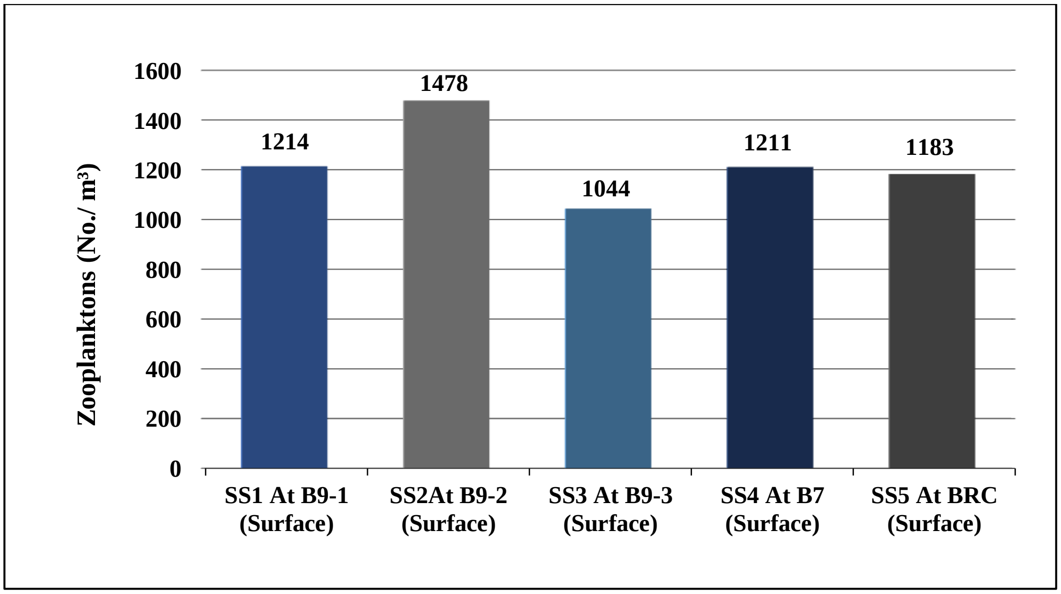
(Source: Primary data generated for this project-Ultra Tech Laboratories).



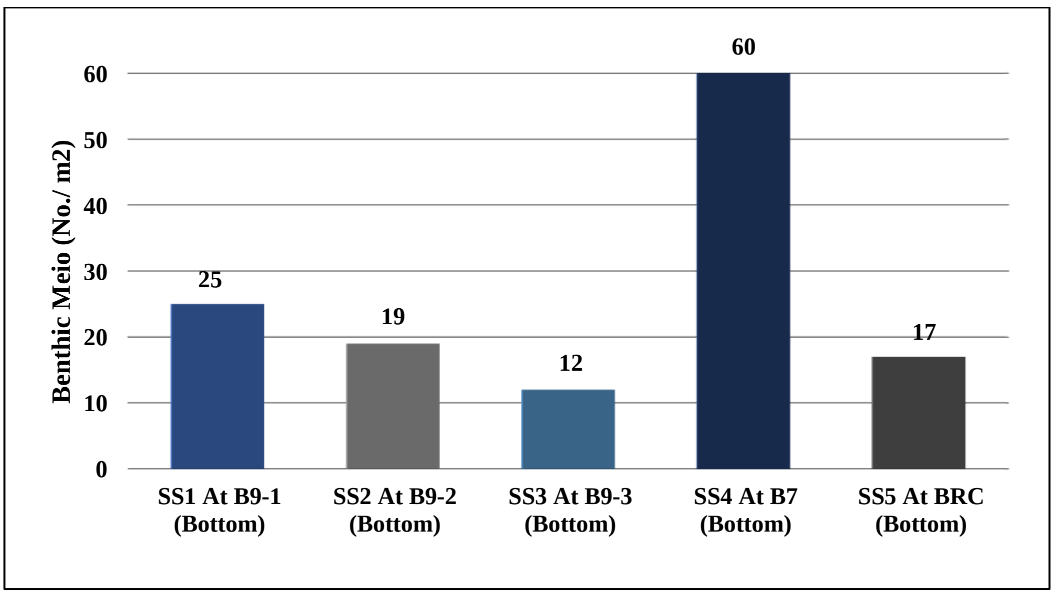
Concentration of Chlorophyll-a at Various Sampling Locations (Surface & Bottom)



Abundance of Phytoplankton at Various Sampling Locations (Surface)



Abundance of Zooplankton at Various Sampling Locations



Abundance of Benthic Meio at Various Sampling Locations (Bottom)

Figure 3.5: Graphical Analysis of Marine Biological Characteristics

(Source: Primary data generated for this project-Ultra Tech Laboratories).

During the study, 36 Phytoplankton genera were observed. Among which the most abundant was Cylindrotheca, Guonardia, Odontella, Thalassiosira and Pseudo-nilzschila which was observed in all 10 samples of 5 sites. Similarly, 17 zooplanktons were observed, in which Copepods, Decapod larves, Gastropods, Isopods, Lamellibranchs, *Lucifer sp,* were the most abundant genera. Likewise, benthos species were studied and were classified up to the groups. The species falling under nine

(9) different groups were identified among which, the most abundant groups were Pelecypods and Polychaetes, followed by Gastropods, Brachyura, and Sergestids.

4. Details of DG Sets and other utilities

Following is the typical minimum requirement that is expected. However, will have to be updated depending on the actual rig that we end up contracting. The DG Sets and Other Utilities on typical offshore Jack up Rig are given in **Table 4.1**.

Table 4.1 Details of DG Sets and Other Utilities

Sl. No.	Details	Make	Capacity	Quantity
1.	Diesel Engines	Caterpillar or Similar	1600 HP	4-5 Nos
2.	Generator (Continuous power)	Kato or Similar	2200-2500 KVA	4-5 Nos
3.	Emergency Generator (Only to be used in emergency))	Caterpillar or Similar	750 HP	1 Nos
4.	Generator	Kato or Similar	475-550 KVA	1 Nos

5. Prediction of various parameters vis-à-vis estimated gas production.

Table 5.1: Proposed Products

S. No	Products	Quantity
1.	Gas (from B-9 Field)	**32 mmscfd** (*Peak Production Rate (PPR) for a plateau period of four (4) years followed by declining profiles*).
2.	Gas (from B-7 Field)	**21 mmscfd** (*PPR for a plateau period of four (4) years followed by declining profiles*).
3.	Oil (from BRC Field)	**800 bopd & 0.4 mmscfd** (*PPR for a plateau period of two (2) years followed by declining profiles*).

The parameters regarding estimated gas production:

B-9-1 well fluid composition & PVT Properties

Well Name	**B-9-1**	
Depth Interval (m)	**2644.5**	
	2648	
Date of collection	**22.10.2005**	**22.10.2005**
	Gas Comp.	**Liquid Comp.**
METH (%Vol)	77.09	0.00
ETHAN(%Vol)	7.77	0.00

Well Name	B-9-1	
Depth Interval (m)	2644.5	
	2648	
Date of collection	22.10.2005	22.10.2005
	Gas Comp.	Liquid Comp.
PROP(%Vol)	4.92	0.02
I BUT(%Vol)	2.81	0.03
N-BUT(%Vol)	2.04	0.03
I-PENT(%Vol)	1.54	0.10
N-PENT(%Vol)	1.25	0.10
N-HEX+(%Vol)	0.00	3.33
N-HEPTANE	0.00	10.46
N-OCTANE	0.00	10.05
N-NONANE	0.00	10.48
N-DECANE	0.00	9.70
N-C11	0.00	8.42
N-C12	0.00	9.45
N-C13	0.00	37.80
CO2(%Vol)	0.30	0.00
N2(%Vol)	2.28	0.00
specific gravity	0.7789	-
net CV (kcal)/m3	10652	-
mol wt	22.48	151.39

B-9-3 well fluid composition & PVT Properties

Well Name	B-9-3	
Depth Interval (m)	2686	
	2688	
Date of collection	15.01.2009	15.01.2009
	Gas Comp.	Liquid Comp.
METH (%Vol)	79.96	0.00
ETHAN(%Vol)	6.69	0.00
PROP(%Vol)	2.96	0.02
I BUT(%Vol)	1.14	0.03
N-BUT(%Vol)	0.73	0.03
I-PENT(%Vol)	0.51	0.10
N-PENT(%Vol)	0.31	0.10
N-HEX+(%Vol)	1.83	3.33
N-HEPTANE	0.00	10.46
N-OCTANE	0.00	10.05
N-NONANE	0.00	10.48
N-DECANE	0.00	9.70
N-C11	0.00	8.42

Well Name	B-9-3	
Depth Interval (m)	2686	
	2688	
Date of collection	15.01.2009	15.01.2009
	Gas Comp.	Liquid Comp.
N-C12	79.96	9.45
N-C13	6.69	37.80
CO2(%Vol)	5.87	0.00
N2(%Vol)	-	0.00
specific gravity	0.7615	-
net CV(kcal)/m3	-	-
mol wt	21.98	151.39

<u>Production Profiles (Indicative)</u>

The Production Forecast for the B-9 field production for 10 years life is as below.

Field Production profile

Date (dd-mm-yyyy)	Condensate Rate (STB/day)	Gas Rate (MMscf/day)	Water Rate (STB/day)	Cum Cond Produced MMstb	Cum Gas Produced Bscf	Cum Water Produced MMstb	Number of Producers
01-04-2020	193.6	32.0	0.0	0.0	0.0	0.0	4.0
01-04-2021	193.6	32.0	3.9	0.1	11.1	0.0	4.0
01-04-2022	193.6	32.0	22.9	0.1	22.2	0.0	4.0
01-04-2023	192.5	31.9	78.4	0.2	33.3	0.0	4.0
01-04-2024	105.9	22.1	136.2	0.3	43.0	0.1	4.0
01-04-2025	130.7	25.7	294.8	0.3	50.0	0.1	4.0
01-04-2026	64.9	17.6	376.7	0.3	56.8	0.2	4.0
01-04-2027	96.7	17.7	618.9	0.4	62.5	0.4	4.0
01-04-2028	68.7	12.2	662.5	0.4	67.5	0.6	4.0
01-04-2029	23.8	2.0	115.5	0.4	70.2	0.7	4.0
01-04-2030	0.0	0.0	0.0	0.4	70.2	0.8	2.0

6. Source of fresh water, water balance and effluent treatment mechanism.

The water required for the proposed drilling is 45–55 KL per day per well. The water balance diagram is given in **Figure- 6.1.**

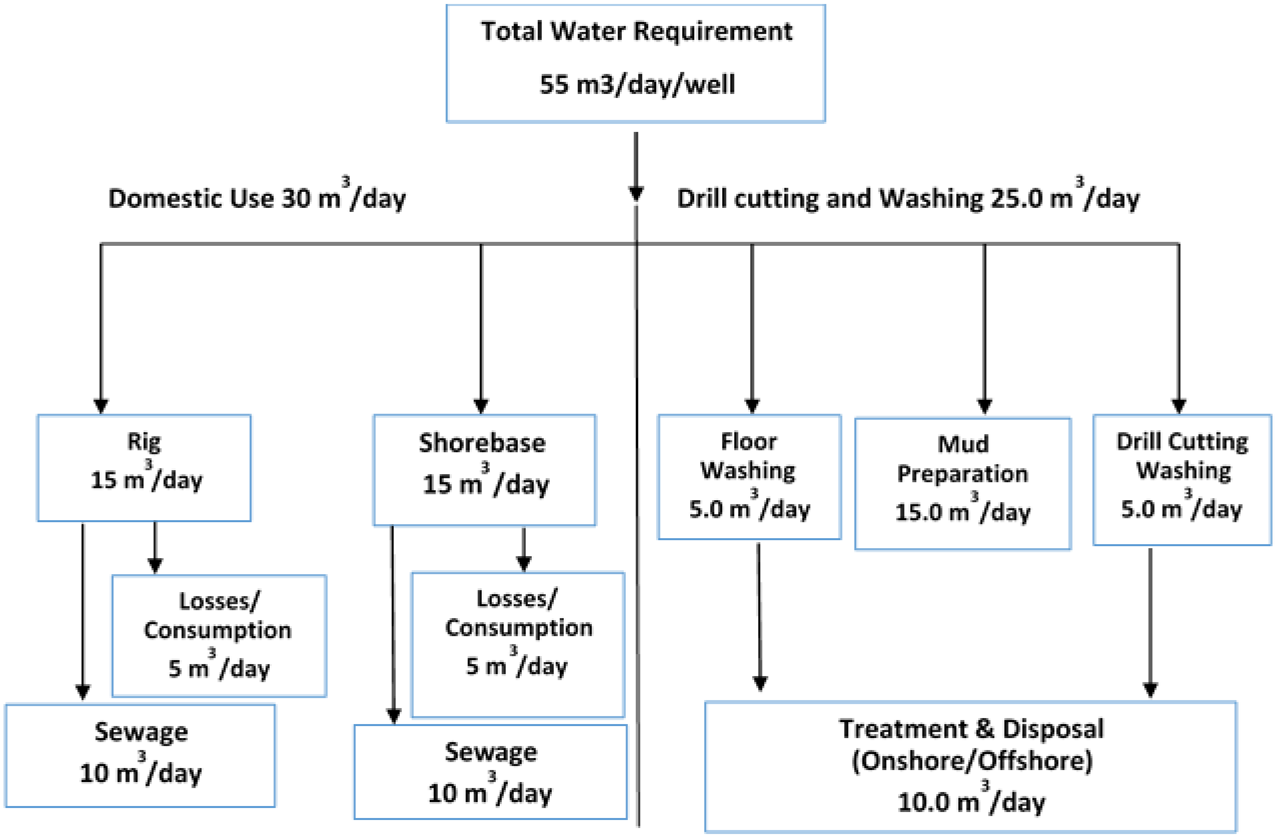


Figure 6.1: Water Balance

7. Procedure for handling oily water discharges from deck washing, drainage systems, bilges, preventing spills and spill contingency plans, treatment and disposal of produced water.

Table 7.1: Procedure/ Plan for handling of Waste Management Plan

Waste Category	Waste Type	Proposed Action
Domestic Waste.	Sewage.	• Sewage will be treated on-board of the rig as per MARPOL regulations. Residual chlorine of the treated sewage will not exceed 1mg/L before disposal.
	Kitchen Waste.	• Biodegradable waste from kitchen, laundries and galleys will be collected, segregated, stored in containers and will be transported onshore and used for composting.
	Combustible Waste (Paper, Rags, Packing Material).	• Waste will be properly segregated (plastics, metal, glass) and transported to onshore base for sale to recycling contractor.
Recyclable Wastes	Tin packs, plastic and glass bottles and other metallic materials.	• Waste will be properly segregated and temporarily stored at onshore segregation pit. The waste will then be delivered to approved recycling contractor.

Waste Category	Waste Type	Proposed Action
Non-Hazardous Wastes	Drill Cuttings	• Cuttings free from WBM will be discharged offshore (as per G.S.R. 546 (E), dated 30/08/05) into sea intermittently, at an average rate of 50 bbl/hr/well from a platform so as to have proper dilution and dispersion without any adverse impact on marine environment. • In case of drill cuttings associated with high oil content from hydrocarbon bearing formation, then it should be ensured that disposal of DC does not have oil content > 10 gm/kg.
	Water Based Drilling Mud (WBM).	• As per G.S.R. 546 (E), dated 30/08/05, WBM/SOBM (is used in special case) will be recycled to the maximum extent. Unusable portion of WBM/SOBM (toxicity of 96 hr LC50 Value > 30,000 mg/L) will be discharged offshore into sea intermittently, at an average rate of 50 bbl/hr/well from a platform so as to have proper dilution and dispersion without any adverse impact on marine environment.
	Drilling & Wash Wastewater	• Drilling and wash water will be treated to conform to limits notified under Environment Protection Act, 1986, before disposal into sea. The treated effluent will be monitored regularly.
Hazardous Waste	Oily waste/ Used Oil	• Used oil will be collected in the designated containers. Vessels will be safely transported to onshore and sent to the approved recycling contractor for its disposal as per the norms notified by MoEF.
	Produced/Formation Water	• Formation/Produced water, if any, separated during hydrocarbon processing will be treated and disposed as per CPCB/MoEF standards.
Bilge Water	Oily Waste	• The oily mixture in bilge water will be processed through an oil filtering equipment (MARPOL regulations 14 & 15, Annex-I)

OIL SPILL CONTINGENCY PLAN (OSCP)

AWEL will have Oil Spill Response contract in place before the start of operations. The agency whom the contract is awarded shall be preparing the Oil Spillage Contingency Plan in compliance with OSLO Convention.

An effective response to oil spill is dependent on the extent of the preparedness of the organization and the people involved. The objectives of the plan are:

- To develop appropriate and effective systems for the detection and reporting of spillage of oil.
- To ensure prompt response to prevent, control, and combat oil pollution.
- To ensure that adequate protection is provided to the public health and welfare, and the marine environment.
- To ensure that appropriate response techniques are employed to prevent, control, and combat oil pollution, and dispose off recovered material in an environmentally accepted manner.
- To ensure that complete and accurate records are maintained of all expenditure to facilitate cost of recovery.

An effective oil spill contingency plan should comprise four components:

a. **Risk Assessment –** To determine the risk of spills and expected consequences,
b. **Strategic Policy –** Defining roles and responsibilities, and providing summary of the rationale for operations,
c. **Operational Procedures –** Establishing procedures when spill occurs,
d. **Information Directory** – Collating support data.

While deciding the plan, it is equally important to take decisions on waste storage and options for treatment, disposal or reuse of waste, keeping in mind the environmental considerations and legal requisites. The Plan should include procedures for mobilizing the logistic support necessary for effective clean up, e.g. distribution of PPE and food for response team, adequate fuel for machinery and transport facility for labour, equipment and recovered wastes.

The Contingency Plan must also focus on timetable for exercises and training for all levels including marine and shoreline response teams and other interested parties. This will help in ensuring that contingency arrangements are in place and personnel have clear understanding of their responsibilities.

Information that should be included in immediate response strategy includes:

a. Actions required to be undertaken by the observer of an incident/the person that identifies that an incident has occurred.
b. Process for informing other site personnel (identifying various site roles).
c. Lines of communication and contact information (i.e. contact phone numbers, radio call protocol, etc.).
d. Steps to identify the most appropriate response strategy/strategies.

The Environmental Officer/Coordinator will be responsible for designing an appropriate post spill environmental monitoring program.

8. Details of blowout preventer installation.

The details of blowout preventors to be installed on the drilling rig, are given below:

Table 8.1 Blowout Preventer Detail

Blow out Preventers Details			
Sl. No.	**Specification**	**Pressure**	**Accessories**
1.	29 ½” Diverter	Working Pressure 500 psi	12” Diverter lines and auto valves
2.	21 ¼” BOP	Working Pressure 2000 psi	2 x 2000 psi Single pipe rams
3.	13 5/8” BOP, Annular Preventer	Working Pressure 10,000 psi	1x 5000 psi Annular Ram 2 x 10000 psi Pipe Rams 1 x 10000 psi Blind / Shear Ram

9. Risk assessment and mitigation measures including independent reviews of well design, drilling and proper cementing and casing practices.

9.1 Introduction

The overall project scope consists of drilling of three (3) wells, two (2) from B-9-1 platform and one (1) from B-9-3 platform. Fluids from both platforms will be comingled at B-9-1. A subsea pipeline of approx. 10.0 KM will transfer gas from B-9-3 to B-9-1 and comingled gas will be delivered to existing ONGC platform (C24-RP) from B-9-1 through another subsea pipeline of length approx.75 KM.

Wellhead platforms will be minimum facilities platforms unmanned with periodical visits through helicopter to conduct routine maintenance, well maintenance and any repair work.

AWEL plans to drill new offshore wells, install well head platforms and subsea pipelines, the details of the proposed facilities are as follows:

1. Drilling and Completion of Wells

- 12 nos. of wells (oil and gas);
  - 7 wells in B-9 Field.
  - 3 wells in B-7 Field.
  - 2 wells in BRC Field.
  - Alternately sub-sea completion wells may also be explored during the design stage.

2. Installation of Wellhead Platforms

- 4 nos. of wellhead platforms (oil and gas);
  - 2 in B-9 Field.
  - 1 in B-7 Field.
  - 1 in BRC Field.

Hazard identification and risk assessment was carried out for the chemicals, which are being proposed to be handled. Safety measures for handling of these chemicals are also proposed.

9.2 Objectives & Methodology of the Risk Analysis Study

To assess the risks posed by a facility, it is necessary to first analyze the risks (risk analysis) and then compare the risks presented with "an acceptability criteria" to determine whether the risks presented by the facility are acceptable. The major steps taken in a risk assessment exercise, looks into the following:

- Define the potential event sequences and potential incidents;
- Evaluate the incident outcome (consequences) & Estimate the incident impact on people, environment and property;
- Estimate the potential incident frequencies;
- Estimate the risk;
- Evaluate the risk; and
- Identify and prioritize potential risk reduction measures if the risk is considered to be unacceptable.

For ease of understanding and administration, the quantitative risk assessment procedure can be divided into component techniques. Depending on the problem on hand and the complexity of the assessment needed, some of the techniques can be simplified or not used. The component techniques used in this report are:

- Hazard Identification;
- Consequence Estimation;
- Likelihood Estimation; and
- Risk Estimation.

9.3 Hazards Identification

The objective of hazard identification is to focus on the type and nature of the hazards which may be present and which require evaluation, to determine the level of risks that are present. The initiating events that may give rise to these hazards such as operator error or equipment failure, etc. are also identified. It is important to point out that the identification of possible hazards does not, in any way, imply that the accidents described will happen. There are many methods available for identifying hazards. The application of hazard identification methods can be time consuming. It is often necessary to concentrate on the more hazardous sections of the installation and deal with other less hazardous sections more superficially.

The hazard identification has been carried out based on the process flow diagram & the nature of material handled.

The following are the loss of containment scenarios identified for the project

1. Well Blow out scenario
2. Leak of piping in well head platform
3. Rupture of piping in well head platform
4. Leak of sub sea piping
5. Rupture of sub sea piping

Development envisages drilling of mainly gas wells at offshore so the chances of getting a ignition source is also very remote so the Leak / Rupture of subsea pipelines does not pose a fire / explosion hazard.
B-9 well case is being discussed in this report as other well cases are smaller and the scenarios will be subset of the cases discussed in this report.

9.4 Weather conditions, Process conditions for the study:

9.4.1 Weather conditions: Once there is a loss of containment its dispersion is governed by the ambient weather conditions. The wind rose presented below are taken for this study

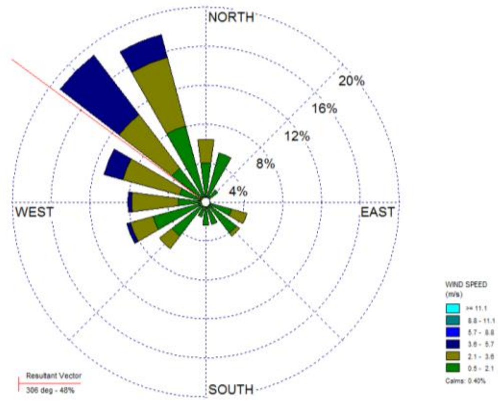


Figure -9.1 Wind Rose for March 2018

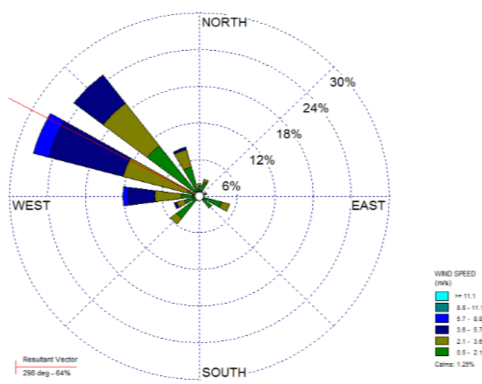


Figure -9.2 Wind Rose for April 2018

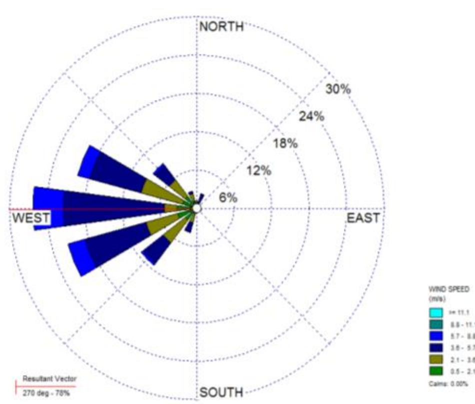


Figure -9.3 Wind Rose for May2018

The ambient air temperature range: maximum and minimum value of mean air temperature in the Arabian Sea is 30.2ºC and 24.04 ºC, respectively.

The sea temperature range: maximum and minimum value of mean sea surface temperature in the Arabian Sea is of 30.8ºC and 26.04 ºC, respectively.

More detailed weather conditions are found in the main EIA report.

9.4.2 Process Conditions:

The worst-case process conditions are taken for evaluation, the summary of process conditions for various Loss of Containment scenarios is summarized as below:

S. No	Scenario	Shut in Pressure of Well Head (Kg/cm^2g)	Max. Operating Temperature (deg C)	Maximum Flow rate (mmcsfd)	Diameter of Well Pipeline (Inches)	Water Depth at well location (meters)
1.	Well Blowout	271 kg/cm^2g	133°C	8 MMCSFD	8	32

S. No	Scenario	Max. Operating Pressure (Kg/cm^2g)	Max. Operating Temperature (deg C)	Maximum Flow rate (mmcsfd)	Diameter of Pipeline (Inches)	Length of pipeline (meters)
1.	Leak of piping in Well Head Platform	144 kg/cm^2g	75	8 MMCSFD	8	200 mtrs
2.	Rupture of piping in Well Head Platform	144 kg/cm^2g	75	8 MMCSFD	8	200 mtrs

Composition of the B9 field fluid is as follows:

Well Name	B-9-1	
Depth Interval m	2644.5	
	2648	
Date of collection	22.10.2005	22.10.2005
	Gas Comp.	Liquid Comp.
METH (%Vol)	77.09	0.00
ETHAN(%Vol)	7.77	0.00
PROP(%Vol)	4.92	0.02
I BUT(%Vol)	2.81	0.03
N-BUT(%Vol)	2.04	0.03
I-PENT(%Vol)	1.54	0.10
N-PENT(%Vol)	1.25	0.10
N-HEX+(%Vol)	0.00	3.33
N-HEPTANE	0.00	10.46
N-OCTANE	0.00	10.05
N-NONANE	0.00	10.48

Well Name	**B-9-1**	
Depth Interval m	**2644.5**	
	2648	
Date of collection	**22.10.2005**	**22.10.2005**
	Gas Comp.	**Liquid Comp.**
N-DECANE	0.00	9.70
N-C11	0.00	8.42
N-C12	0.00	9.45
N-C13	0.00	37.80
CO2(%Vol)	0.30	0.00
N2(%Vol)	2.28	0.00
specific gravity	0.7789	-
net CV(kcal)/m3	10652	-
molwt	22.48	151.39

9.4.3 Population

The facility is unmanned, however on an average, weekly twice a group of five people can be expected to carry out routine inspections & maintenance for a period of twelve hours.

9.5 Consequence Assessment

Consequence analysis methodology comprises source term and physical effects modelling. Software package DNV PHAST has been used for the calculation of the consequence effects. Consequence modelling has been carried out for the identified hazard scenarios, including release rates, thermal radiation extent, dispersion and explosion overpressure distance.

The study is carried out in line with the CPR 18E (Guidelines for Quantitative Risk Assessments) & Indian standard IS 15656 (Hazard Identification & Risk Analysis - code of practice)

9.5.1 Jet Fire

Jet fires typically result from the combustion of a material as it is being released from a pressurized process unit. In the event of a continuous pressurized release of either gas or liquid or two-phase fluid, a jet of fluid will form. If ignited, this jet will produce an elongated flame or jet fire. The hazard from jet fires are to a certain extent directional. There are two types of hazards from jet fires. The first is when the jet fire impinges upon a storage vessel or other process equipment and causes them to fail. The second is from thermal radiation from the burning jet flame.

Scenario	Jet Fire Downwind Damage Distances in meters					
	Weather Condition 1.5 F			Weather Condition 5 D		
	4 Kw/m^2	12.5 Kw/m^2	37.5 Kw/m^2	4 Kw/m^2	12.5 Kw/m^2	37.5 Kw/m^2
Well Blow out (B9 - Gas Well)	254.59	53.18	NR	307.48	144.36	NR
Well Head Platform piping Leak (B9 - Gas Well)	42.14	26.76	NR	42.99	28.31	NR
Well Head Platform piping Rupture (B9 - Gas Well)	248.77	173.33	129.33	248.89	182.15	137.16

Legend: NA - Not Applicable, NR - Not Reached

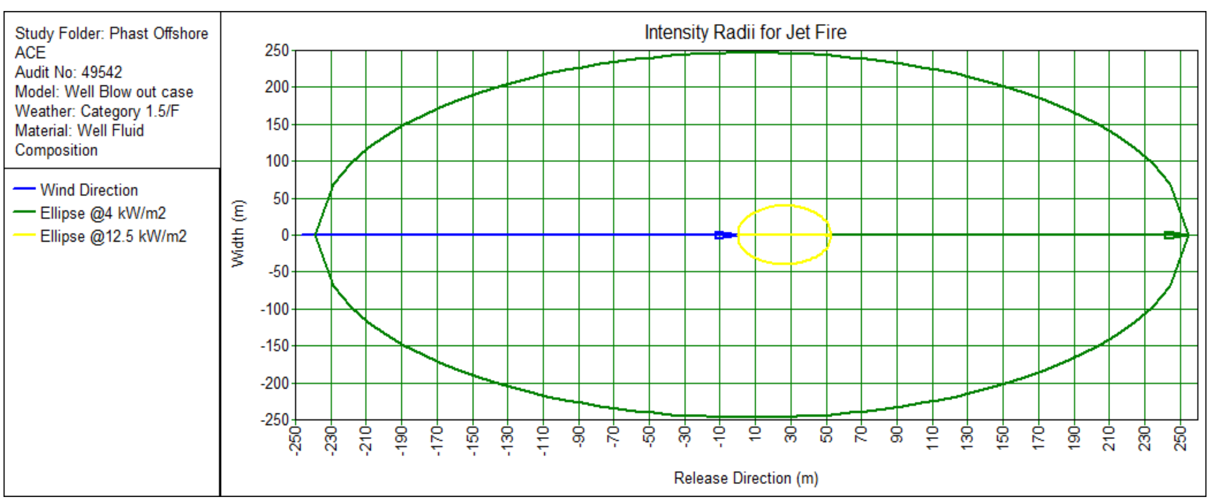
Analysis:

The worst case scenario is when Catastrophic Rupture of Well Head Platform piping (B9) occurs under weather condition 5D with 37.5 Kw/m2 heat radiation distances reaching upto 137.16 mtrs which can cause structural damage, heat radiation intensity of 12.5 Kw/m2 reaches upto 182.15 mtrs and people exposed to this heat radiation intensity for a period of one minute have significant likelihood of death.

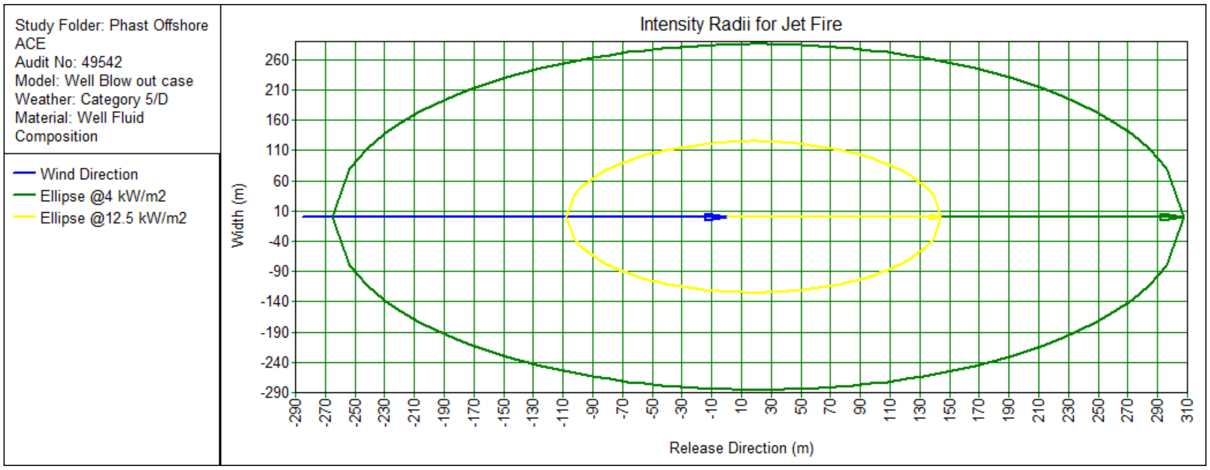
The corresponding software outputs are also presented below:

Well Blow out (B9 - Gas Well)

Weather Condition 1.5 F

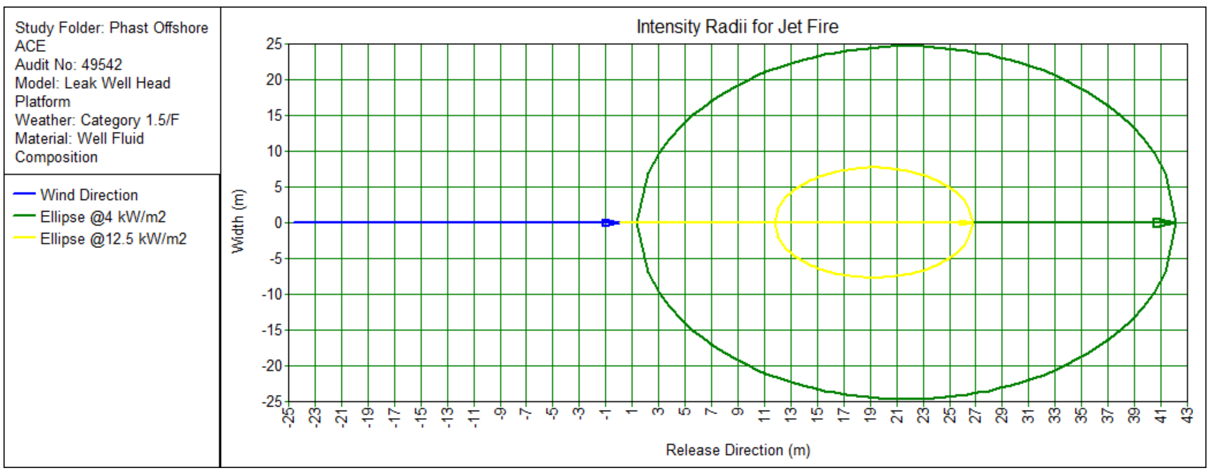


Weather Condition 5 D:

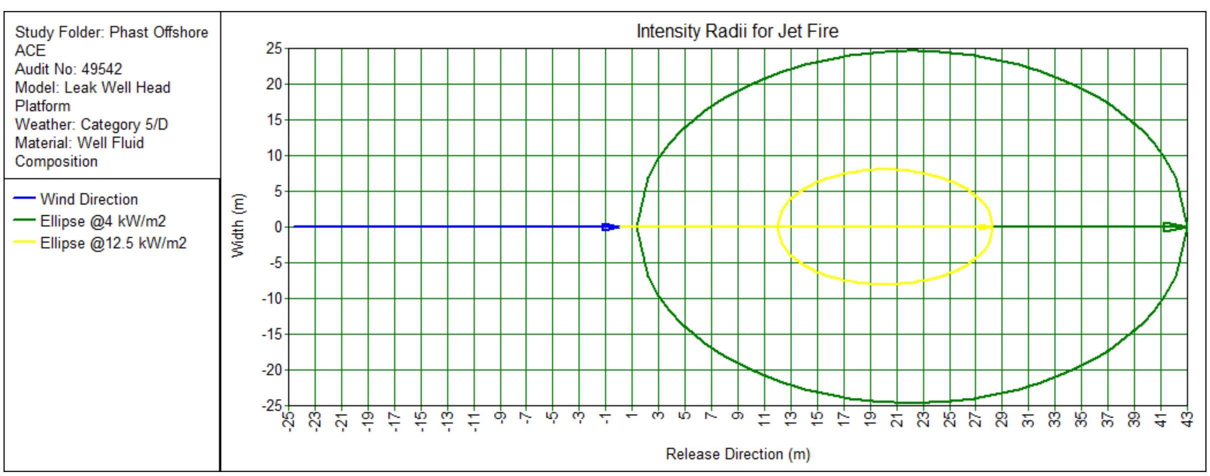


Well Head Platform piping Leak (B9 - Gas Well)

Weather Condition 1.5 F:

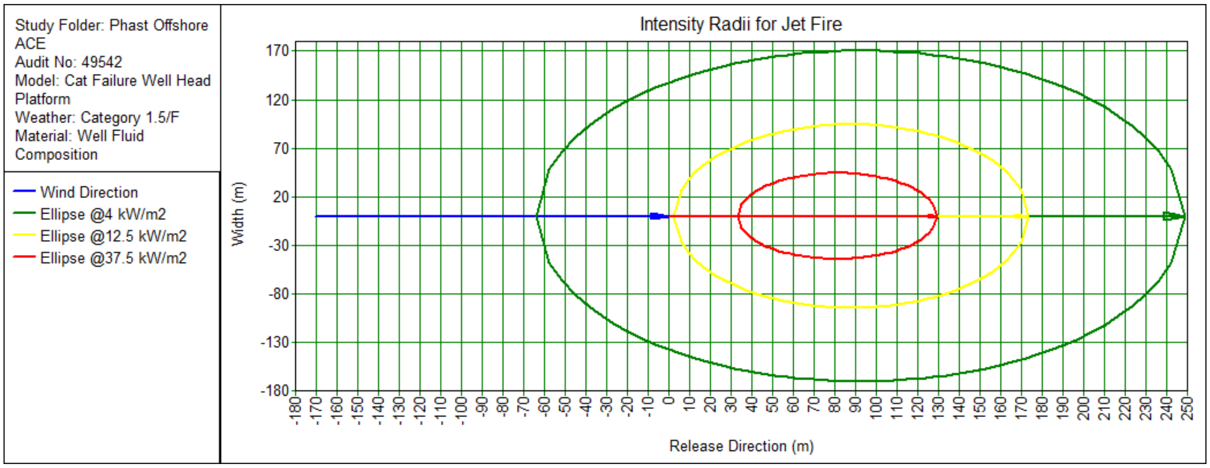


Weather Condition 5 D:

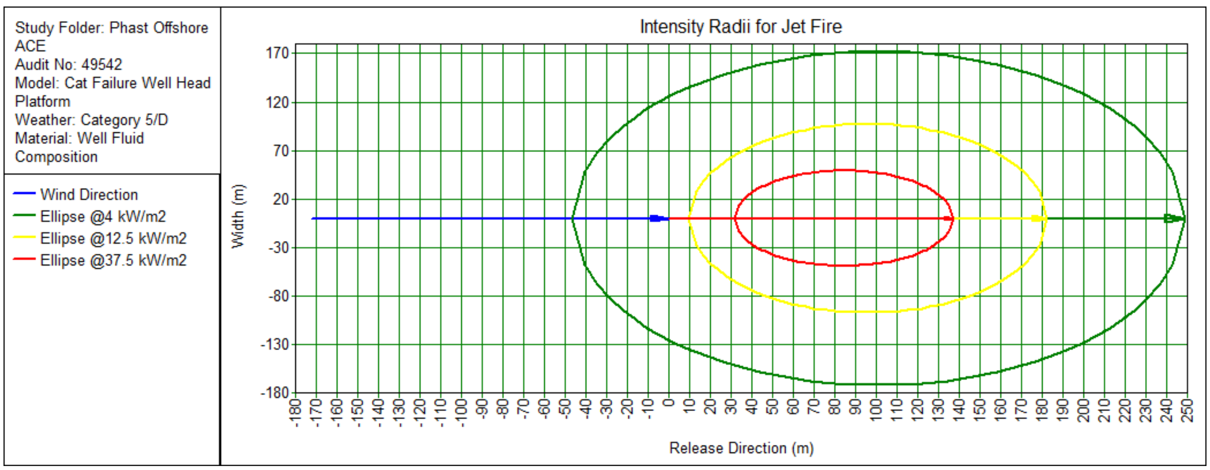


Well Head Platform piping Rupture (B9 - Gas Well)

Weather Condition 1.5 F:



Weather Condition 5 D:



9.5.2 Pool Fire / Oil Spill Case

A pool fire is a turbulent diffusion fire burning above a horizontal pool of vaporising hydrocarbon fuel where the fuel has zero or low initial momentum. Fires in the open will be well ventilated (fuel-controlled), but fires within enclosures may become under-ventilated (ventilation-controlled). Pool fires may be static (e.g. where the pool is contained) or 'running' fires

The primary effects of such fires are due to thermal radiation from the flame source. The radiative heat transfer and the resulting burning rate increases with the pool diameter. For pool diameters greater than 1 m, radiative heat transfer dominates and the flame’s geometric view factor is constant. Thus, a constant burning rate is expected.

The wells under discussion are only gas wells so Pool fire are not expected out gas. However, the BRC well produces small quantities of Oil which when spilled can create a Oil spill over water whose distances are presented below

In this project the BRC wells handle oil and can lead pool fire on waters, But considering the percentage of water cut in oils and the probability of ignition of these oils this scenario becomes less cresible. However, the Oil spill case still remains cresible. So for the BRC wells the Oil spill case is modelled as it presents an environmental hazard. The production rate of BRC wells is 800 bopd.

Scenario	Pool Diameters Distances in meters	
	Weather Condition 1.5 F	Weather Condition 5 D
BRC wells subsea piping rupture	31.67	27.15

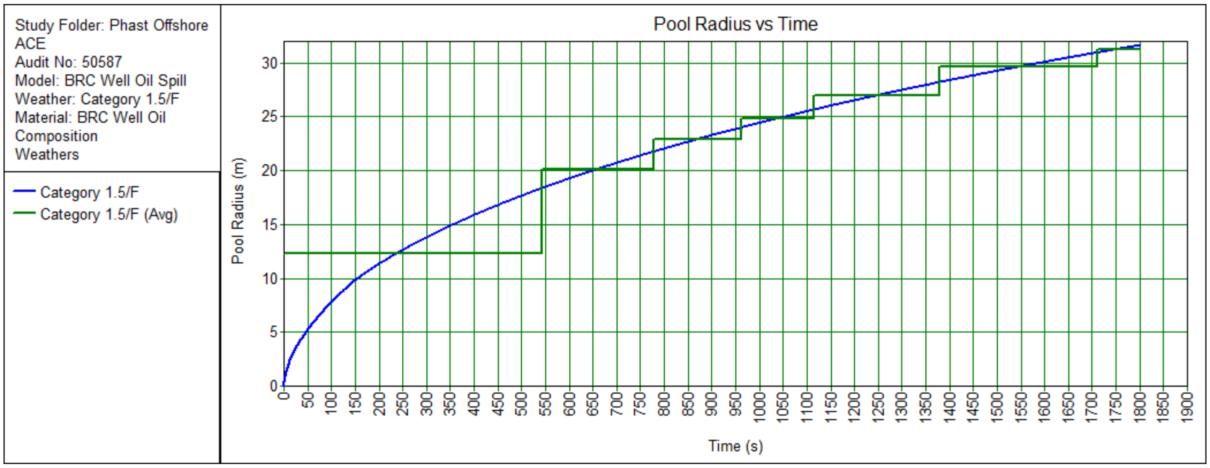
Legend: NA - Not Applicable, NR - Not Reached

Analysis:

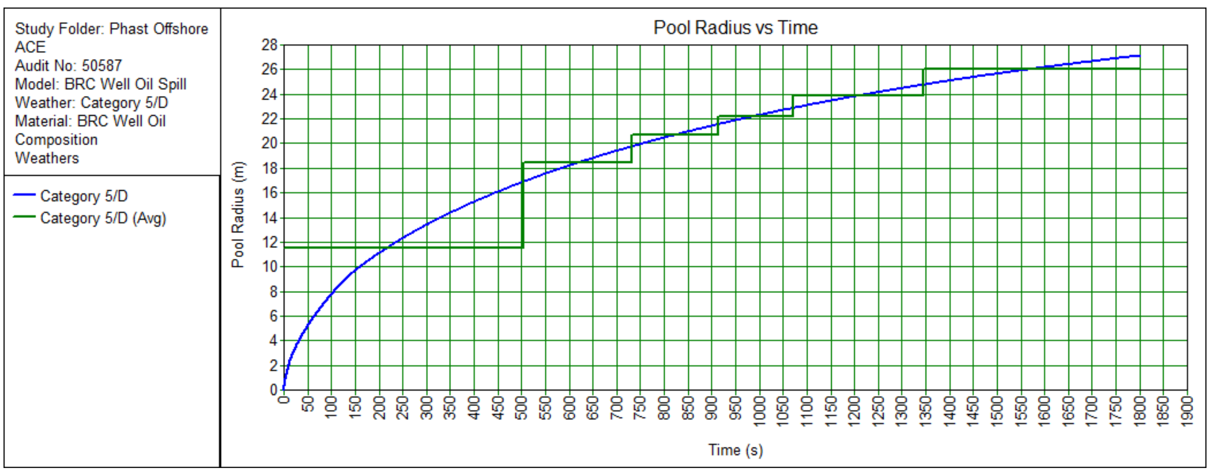
The worst-case scenario is when Catastrophic Rupture of BRC wells subsea piping rupture occurs under weather condition 1.5F with pool diameter reaching upto a distance of 31.67 meters.

The corresponding software outputs are also presented below

Weather Condition 1.5 F



Weather Condition 5 D



9.5.3 Vapor Cloud Explosion

The explosion resulting from the ignition of a cloud of flammable vapor, gas, or mist in which flame speeds accelerate to sufficiently high velocities to produce significant overpressure.

Scenario	Vapor Cloud Explosion Downwind Damage Distances in meters					
	Weather Condition 1.5 F			Weather Condition 5 D		
	0.03 bar	0.1 bar	0.3 bar	0.03 bar	0.1 bar	0.3 bar
Well Blow out (B9 - Gas Well)	1373.74	1303.83	1286.41	336.41	172.15	110.99
Well Head Platform piping Leak (B9 - Gas Well)	69.18	52.44	46.21	67.79	51.85	45.92
Well Head Platform piping Rupture (B9 - Gas Well)	508.34	400.32	360.11	497.84	395.85	357.87

Legend: NA - Not Applicable, NR - Not Reached

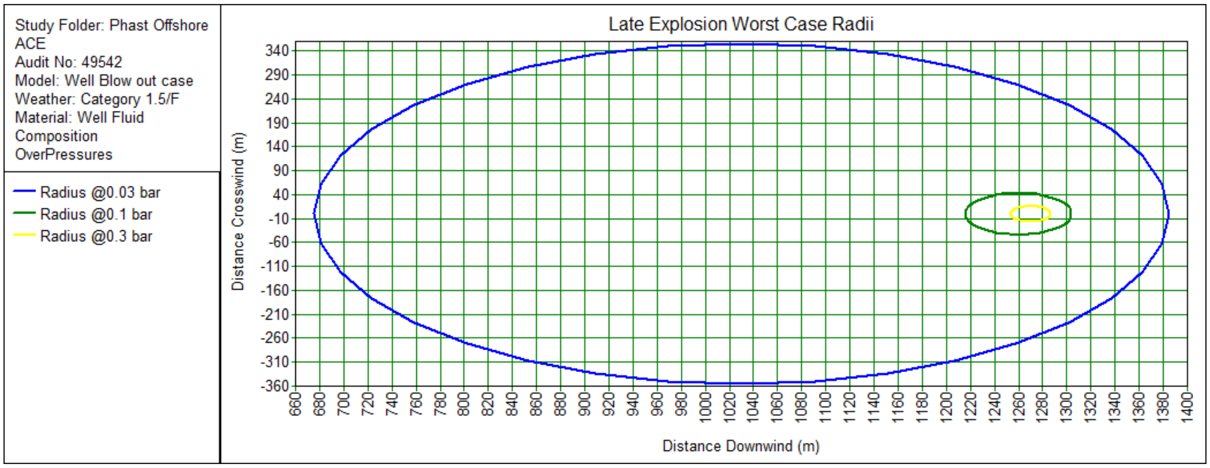
Analysis:

The worst case scenario is when Catastrophic Rupture of Well Blow out (B9 - Gas Well) occurs under weather condition 1.5F with 0.3 bar overpressure distances reaching upto 1286 mtrs which can cause structural damage, Overpressure intensity of 0.1 bar reaches upto 1303 mtrs and people exposed to this Overpressures can have 10% fatality probability & Repairable damage to plant equipment & structure.

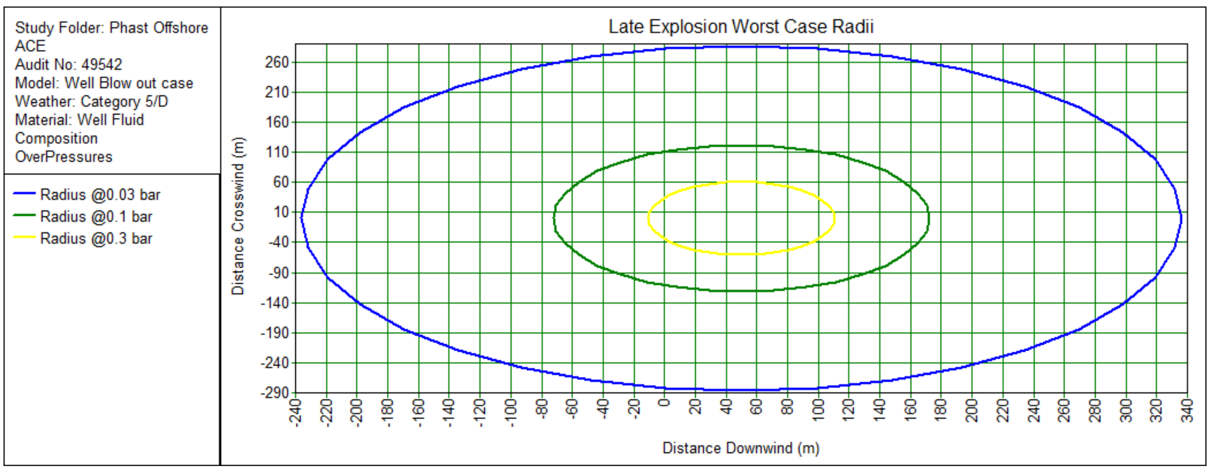
The corresponding software ouputs are also presented below

Well Blow out (B9 - Gas Well)

Weather Condition 1.5 F

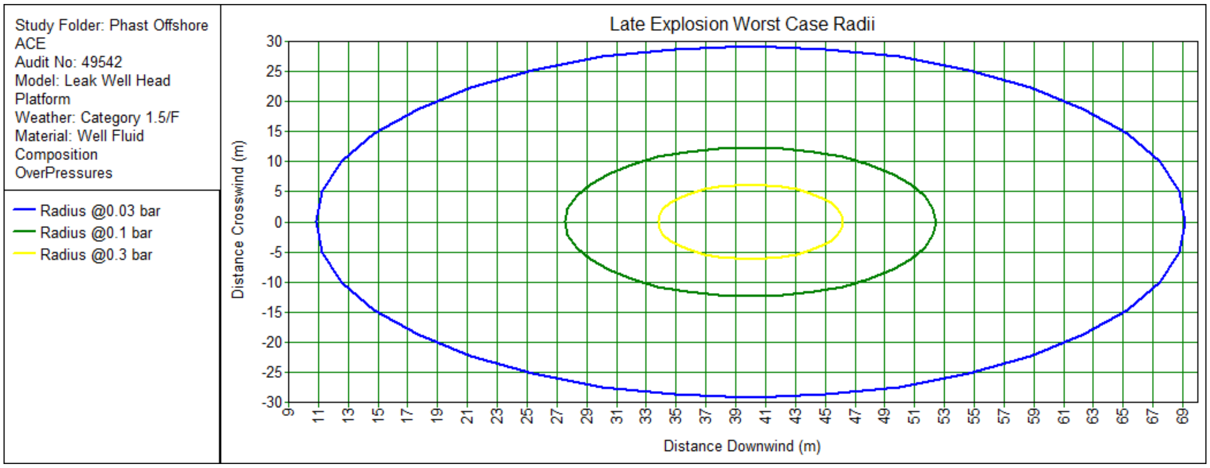


Weather Condition 5 D

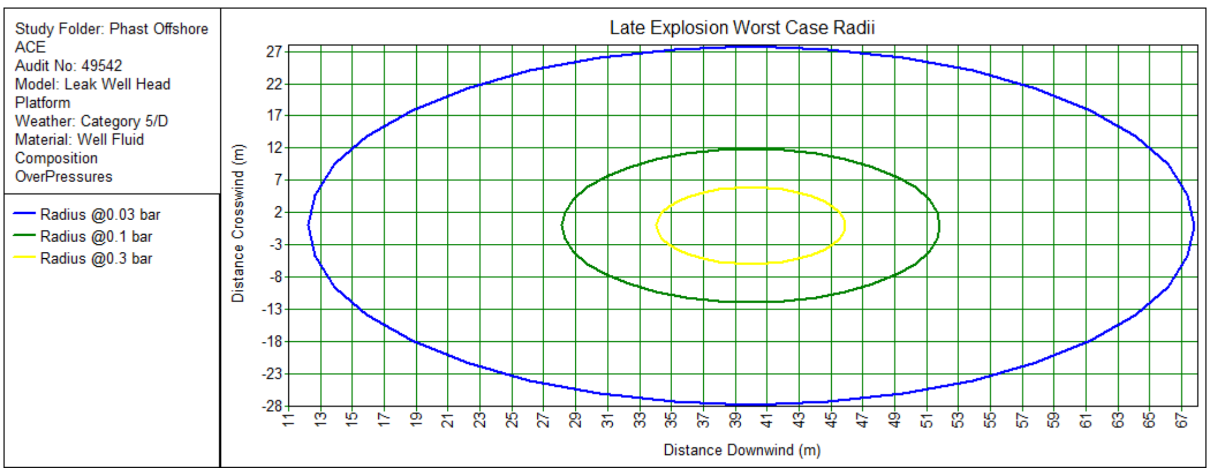


Well Head Platform piping Leak (B9 - Gas Well)

Weather Condition 1.5 F

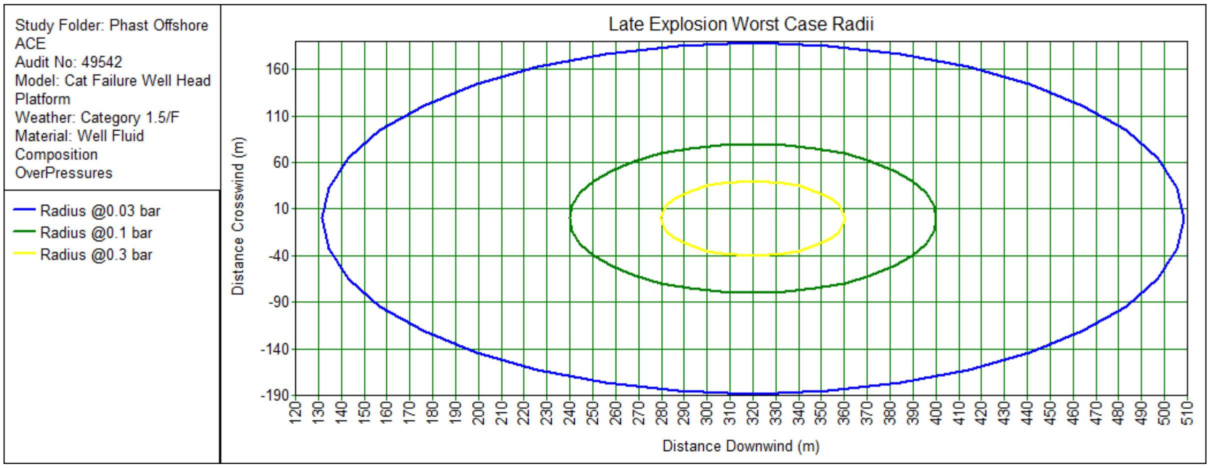


Weather Condition 5 D

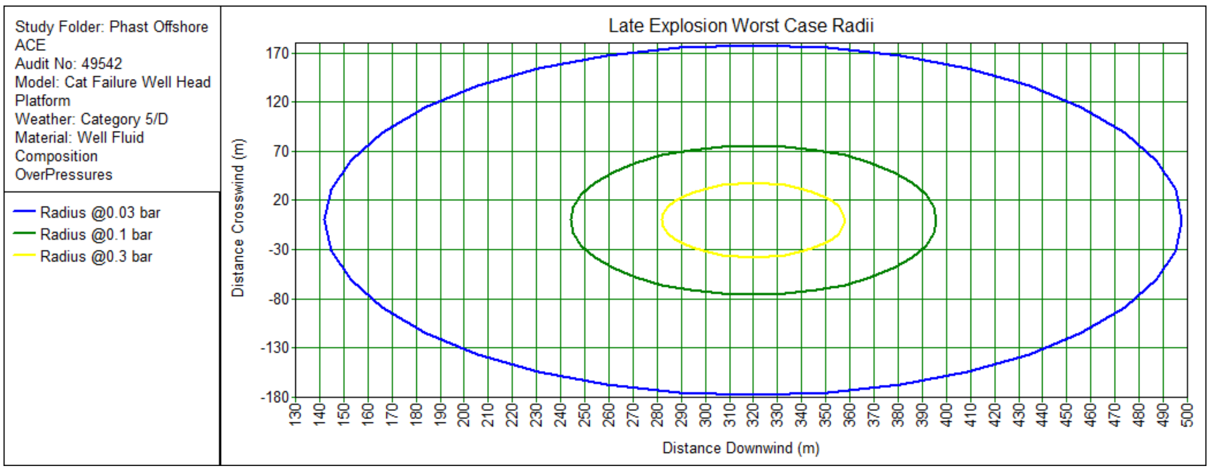


Well Head Platform piping Rupture (B9 - Gas Well)

Weather Condition 1.5 F



Weather Condition 5 D



9.5.4 Flash Fire

A flash fire is a sudden, intense fire caused by ignition of a mixture of air and a dispersed flammable substance.

It is characterized by high temperature, short duration, and a rapidly moving flame front.

The flash fires can be experienced upto the lower flammable limit points of dispersion.

Scenario	Flash Fires Downwind Damage Distances in meters	
	Weather Condition 1.5 F	Weather Condition 5 D
	3.419E4 ppm (Gas)	3.419E4 ppm (Gas)
Well Blow out (B9 - Gas Well)	997	20
Well Head Platform piping Leak (B9 - Gas Well)	22	21
Well Head Platform piping Rupture (B9 - Gas Well)	142	137

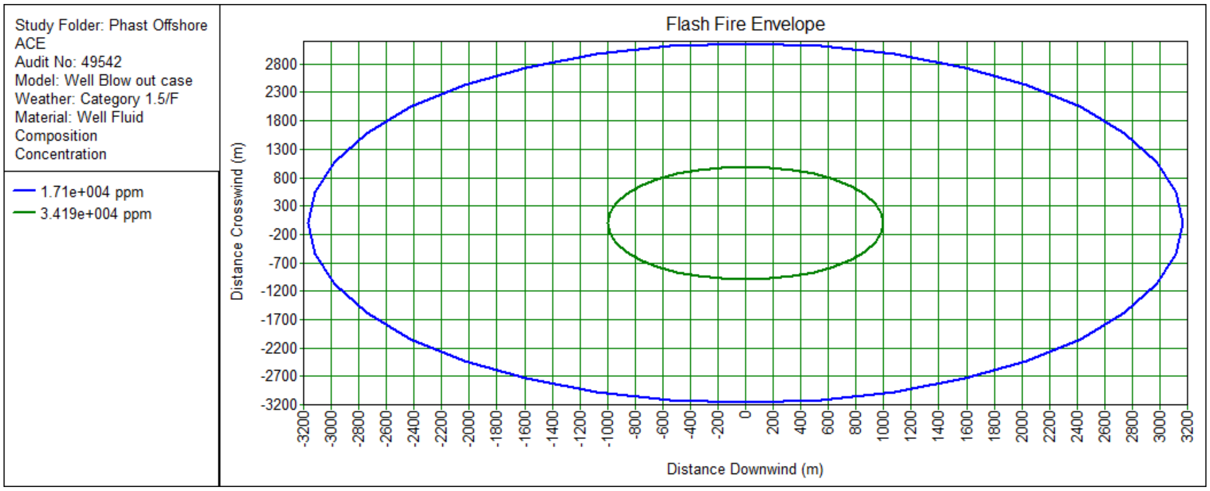
Analysis:

The worst case scenario is when Catastrophic Rupture of Well Blow out (B9 - Gas Well) occurs under weather condition 1.5F with flash fire distances reaching upto 997 mtrs.

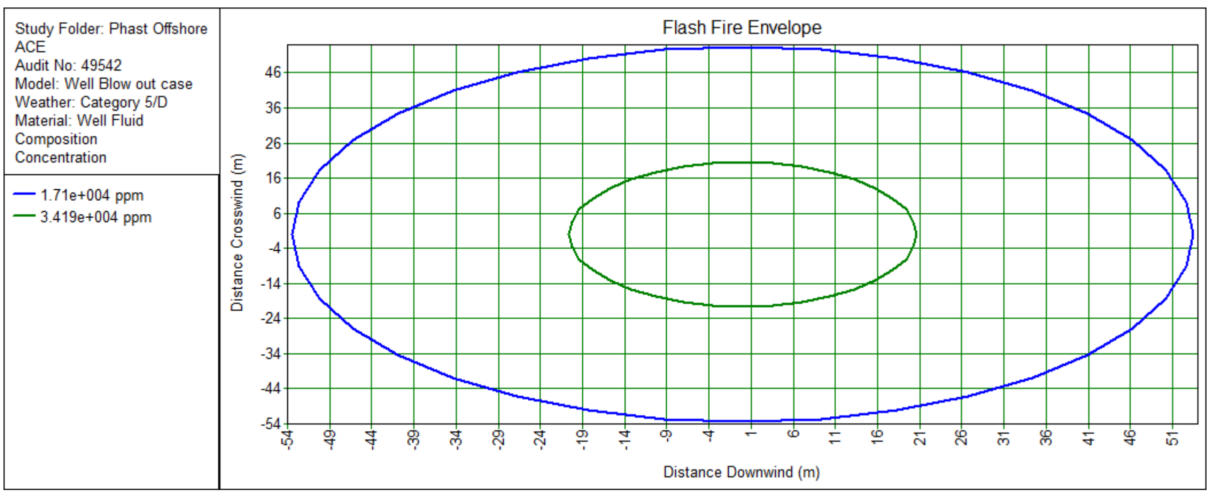
The corresponding software outputs are also presented below

Well Blow out (B9 - Gas Well)

Weather Condition 1.5 F

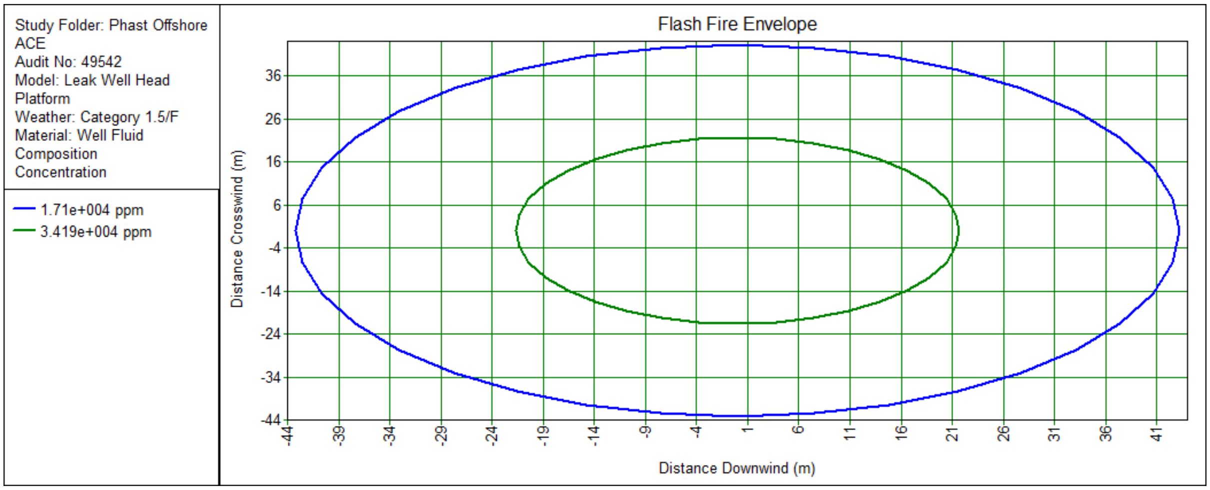


Weather Condition 5 D

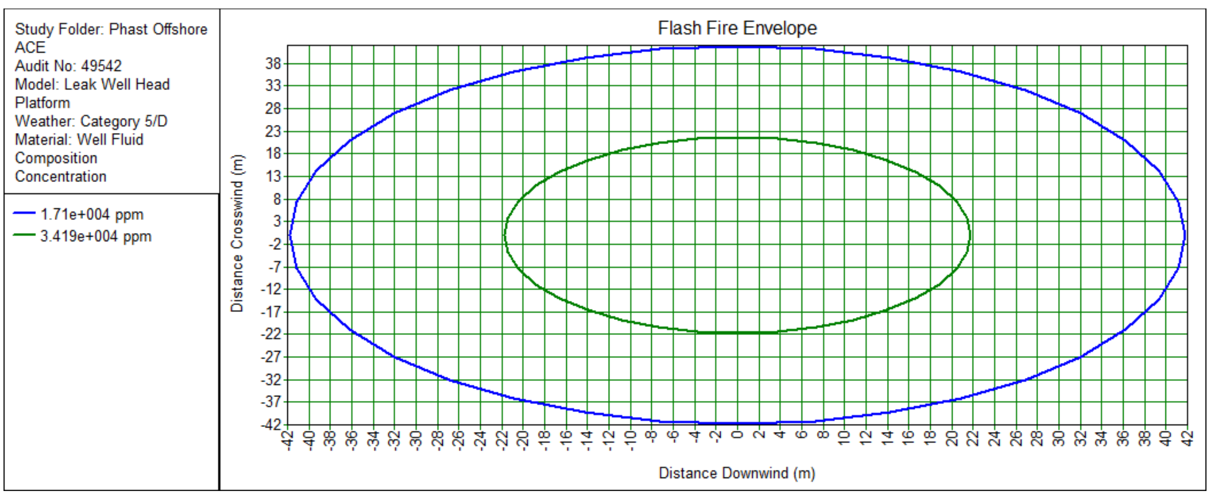


Well Head Platform piping Leak (B9 - Gas Well)

Weather Condition 1.5 F

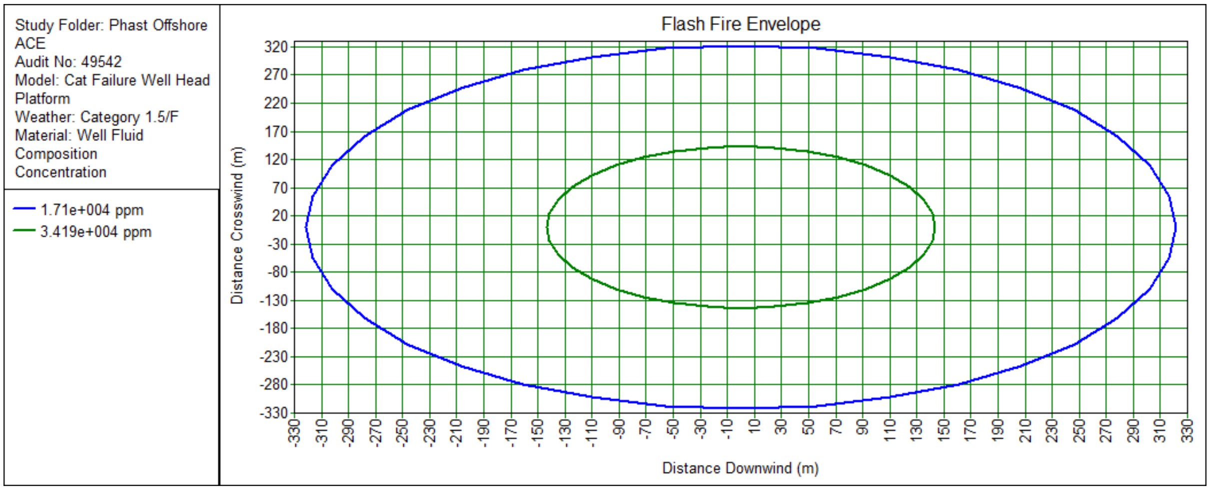


Weather Condition 5 D

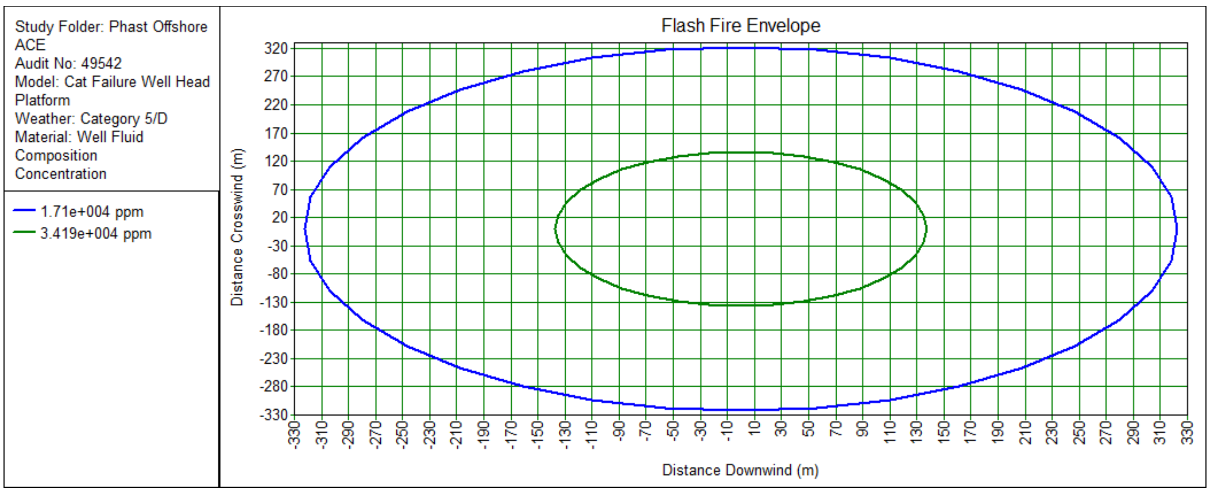


Well Head Platform piping Rupture (B9 - Gas Well)

Weather Condition 1.5 F



Weather Condition 5 D



9.6 Likelihood Estimation

Likelihood estimation is the methodology used to estimate the frequency or probability of occurrence of the major hazard scenarios considered.

The failure rate data used in this risk analysis study is based on typical failure frequencies published in OGP database & OREDA

There are several approaches to predicting failure rates including the construction of logic trees (fault trees). For the specific requirements of this analysis, the best and the most cost effective estimates of failure rates were obtained by assuming basic failure rates from standard failure database and then to fit the conditions that are expected at this site. The relevant conditions are primarily:

- Materials of construction;
- Mode of construction;
- Design of equipment;
- Proposed inspection and maintenance routines;
- Exposure of the equipment; and
- General knowledge of hazards involved.

For the requirements of this study, data presented in OGP database & OREDA will be used and modified to fit the conditions that are expected at this site.

Failures due to the causes discussed in can result in a leak (High Frequency Low Severity) and catastrophic rupture (instantaneous release of complete inventory) (Low Frequency High Severity).

9.6.1 Base Failure Frequency:

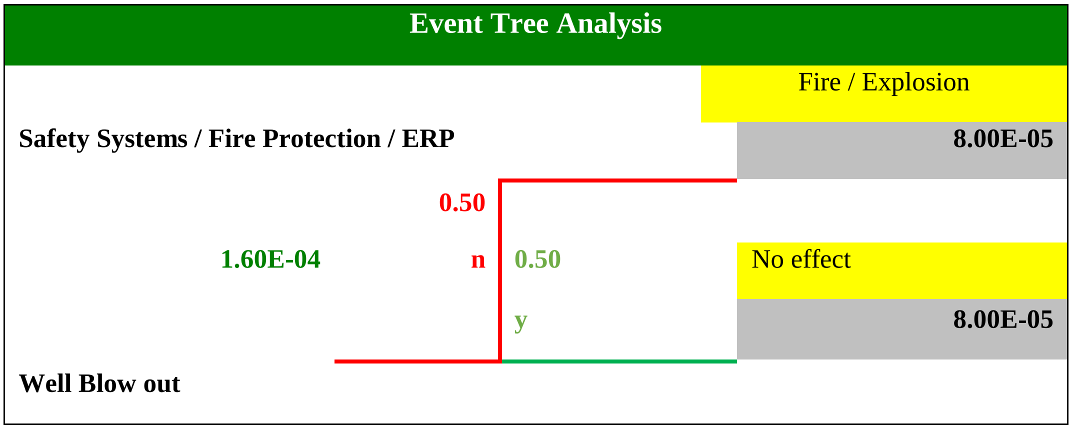
The base failure frequencies for the various loss of containment scenarios under consideration are as follows

Scenario	Failure Frequency
	Per year
Well Blow out (B9 - Gas Well)	1.6 E-4
Well Head Platform piping Leak (B9 - Gas Well)	5.84E-4
Well Head Platform piping Rupture (B9 - Gas Well)	1.17E-4

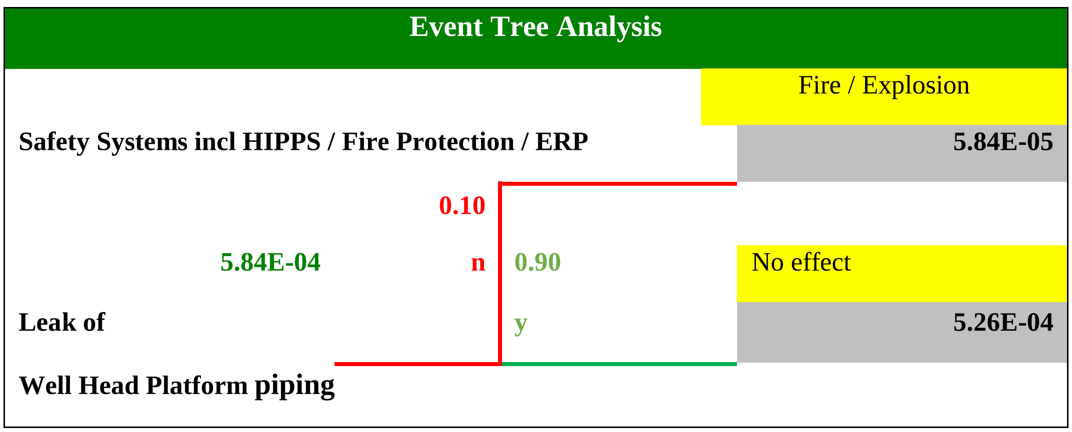
9.6.2 Event Tree

The various safety systems like of this proposed facility like HIPPS, Automatic Leak Detection & control etc. are given credits to calculate the failure rate of the identified loss of containment scenarios.

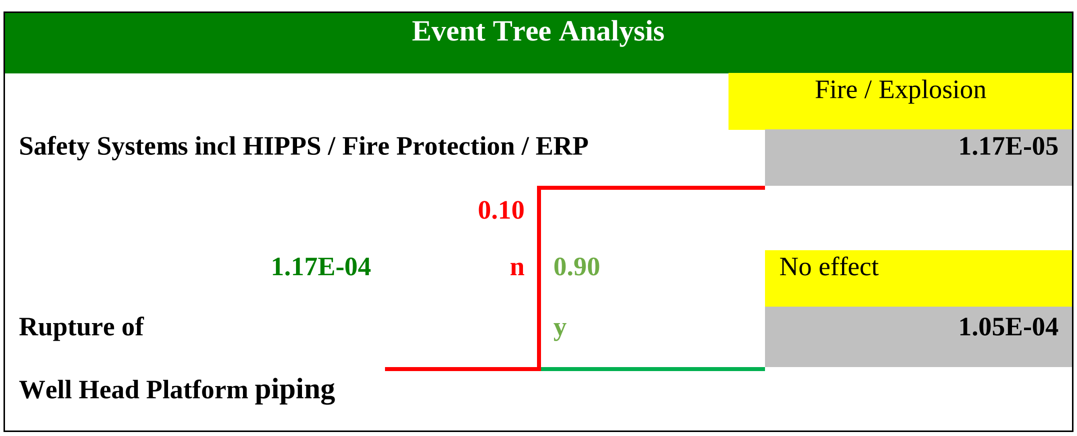
Well Blow out Case:



Leak of WellHead Platform piping:



Rupture of Well Head piping:



9.6.3 Calculated Failure Frequency:

Based on the event tree discussed above the calculated failure frequency for the various identified loss of containment scenarios are as follows

Scenario	Failure Frequency
	Per year
Well Blow out (B9 - Gas Well)	8.00E-5
Well Head Platform piping Leak (B9 - Gas Well)	5.84E-5
Well Head Platform piping Rupture (B9 - Gas Well)	1.17E-5

9.7 Risk Assessment

9.7.1 Risk Estimation

Individual Risk Per Annum (IRPA) is the frequency at which an individual suffers a defined degree of injury.

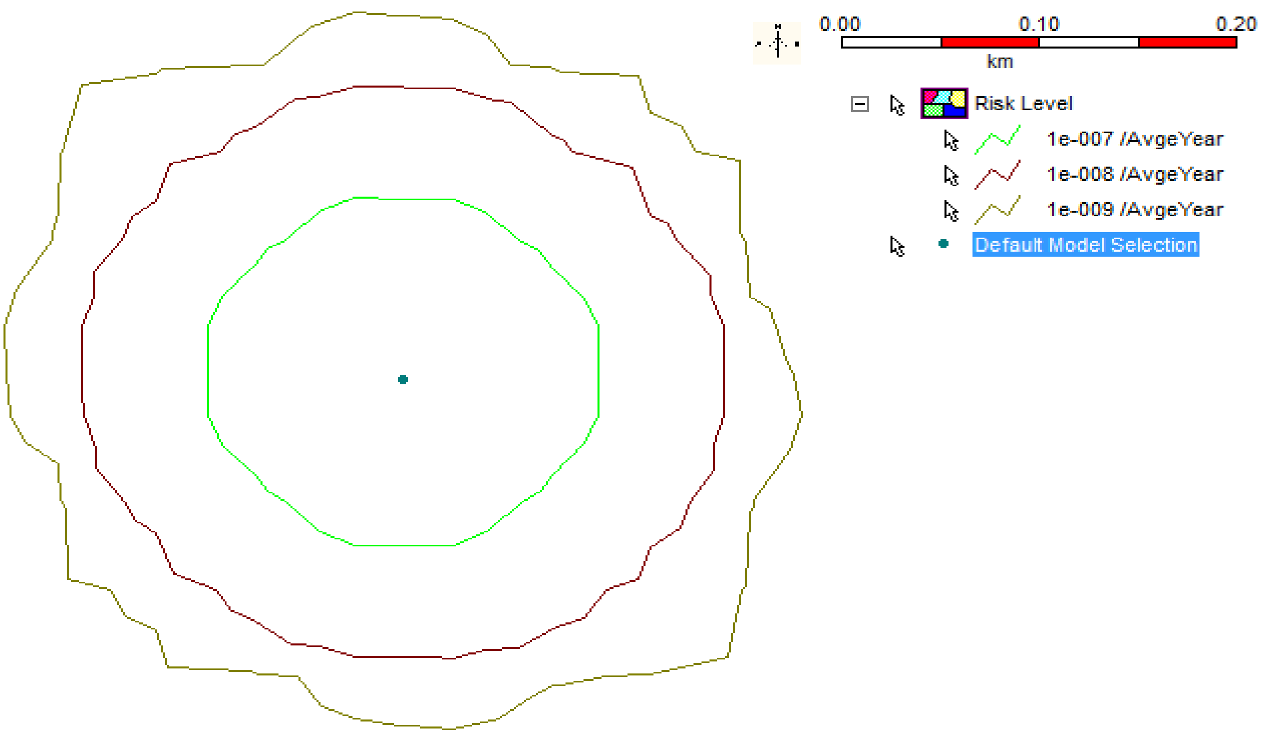
The product of the likelihood of an event and the magnitude (severity) of the outcome of that event. The risk is expressed in terms of fatalities per year.

Individual risk is usually used to indicate how significant the imposition of risk is compared with the background risk an individual is normally exposed to.

Using the process parameters (defined in section 9.4.2), weather conditions (defined in section 9.4.1), Population distribution (defined in section 9.4.3) and the calculated failure frequencies (Section 9.6.3) the Individual Risk per Annum(Individual Risk Per Annum) is calculated using software. The calculated Individual Risk Per Annum for various scenarios are presented below

Scenario	Individual Risk Per Annum
Well Blow out (B9 - Gas Well)	1.89E-6
Well Head Platform piping Leak (B9 - Gas Well)	2.96E-9
Well Head Platform piping Rupture (B9 - Gas Well)	2.07E-7
Overall	6.35E-6

The overall Individual Risk Contour is presented below



9.7.2 Risk Acceptability:

The risk acceptability criteria in India as per IS 15656- Hazard Identification & Risk Analysis Code of practice, for new facilities is **1E-5** / annum,

From the risk assessment results, it can be seen that the facility poses risk level which falls well within acceptable limits.

Overall Individual risk value is **6.35E-6**

Results are in compliance with the current planning guidelines and falls under acceptable limits as per IS 15656 - Hazard Identification & Risk Analysis Code of practice.

The inherent hazard associated with the operations is potential fires and explosion. All incidents as demonstrated by this quantified risk assessment are well outside any habitat areas.

Recommendations & Conclusion

The main hazards associated with the facility are due to fire and explosion. Potential major accidents involving fire and explosion were evaluated in the risk assessment study. Results indicate that the damage potential associated with such accidents is likely to be limited to Offshore areas only.

Following controls are available,

- Fire & Gas detection system is available;
- HIPPS system is available;
- Scheduled inspection & maintenance program is available
- Automatic leak detection & controls systems are in place and there is a designated Control room
- Operation & Control Philosophy is available.

Following risk reduction measures need to be ensured at site to maintain the risks within the acceptable levels:

- Facility to be designed & maintained as per the standards practices as prescribed in API standards (API RP 17D - Design and Operation of Subsea Production Systems-Subsea Wellhead and Tree Equipment, API RP 14 E - Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, API RP 14 C -Analysis, Design, Installation and Testing of Basic Surface Safety Systems on Offshore Production Platforms, API- RP 53 - Blowout Prevention Equipment Systems for Drilling Operations,) including the *well design, drilling and proper cementing and casing practices*.
- Fire & Gas detection & protection systems (Example: Fire Hydrant system, Portable fire extinguishers, Sprinkler systems) are to be maintained as per the applicable standards to ensure its effectiveness.
- Standard Operating procedure / Standard Maintenance procedures to be developed.
- To prepare a Comprehensive Contingency Plan, to prevent and control the accident.
- Stability of Rig during storm etc. The Rig Survival Conditions shall be checked against the existing weather parameters and met-ocean conditions prevailing at the well location prior to deployment. In the event of storm conditions are beyond the Survival Conditions of the rig, the personnel shall be evacuated and the rig shall be towed to a safe location as per the Company’s approved ERP.
- The Emergency Response Plan to be reviewed and regularly updated.
- Training plan to be developed and ensure all concerned are trained as per the training plan.

The Risk Register for the B-9 Drilling Program is given below:

B-9 Drilling Program Risk Register

I = Impact, P = Probability, E = Exposure

VH = Very High, H = High, L=Low

Risk Title	Description of Risk / Hazard	Team Assessment			Risk Type HSE (H) Economic (E)	Comments & Control Measures
		I	P	E		
Major Topic	**General**					
Well Design	Well design should ensure all available information from Exploration is used. e.g. pore pressure data.	VH	L	H	E,H	Extremely thorough review made of all offset wells. Well design information documented.
Shallow gas	Encountering shallow gas and dealing with it in a safe manner.	M	L	M	E	Very low probability.
WOE	Equipment not delivered to the rig in time, equipment failure and equipment required for unplanned operations.	VH	M	H	E	Develop detailed equipment lists, load-out schedules. Ensure equipment inspected before shipping. QC equipment on arrival at location.
Drill string failure	Failure of down hole tubulars	M	L	M	E	Thorough inspection of all tubulars before accepting rig.
Well Control (influx)	Controlling and preventing influx of hydrocarbons or water. Insufficient information or wrong interpretation of information to predict pore pressure increases.	M	L	M	E, H	Low probability; gradients in the area are well known.

Risk Title	Description of Risk / Hazard	Team Assessment			Risk Type HSE (H) Economic (E)	Comments & Control Measures
		I	P	E		
Stuck pipe	Stuck pipe due to differential or mechanical sticking	M	M	M	E	Possible occurrence in sandy sections. Mud will contain bridging agents to minimise seepage. API HPHT fluid loss will be tightly controlled.
Failure of Service company equipment	Failure of critical service company equipment during operation.	M	M	M	E	Ensure equipment inspected before shipping. QC equipment on arrival at location.
Rig equipment failure	Failure of rig equipment e.g. top drive, mud pumps etc.	H	L	M	E	Full QC inspection of rig performed by Third Party. All critical items to be closed out before day-work commences.
Environmental Damage and Hazardous Waste	Failure to properly dispose of waste and hazardous materials	M	M	M	E,H	Review environmental /disposal procedures with drilling contractor. Properly plan site restoration.
Major Topic	**26” hole**					
Washout below or around 30” pipe	Major hole enlargement in soft sand conductor shoe. Lost returns around pre-set conductor.	M	H	M	E	Maintain low-end rheology and high gel content in spud mud. Spud with reduced circulation rate and keep rate low until firm formations are penetrated.
BHA pick up / drilling 26” hole	Personnel exposure to slip/trips/falls and trapped fingers	M	H	M	H,E	Pre-task safety tool box talks required
Mud Mixing	Personnel exposed to operations, manual handling of products.	L	H	M	H,E	Pre-task safety tool box talks required and PPE/MSDS at site
Losses while drilling 26” hole	Low strength of the surface formation; or annulus overloaded with solids	M	H	L	E	Coarse, mixed-media LCM to be available on rig site prior to spud.

Risk Title	Description of Risk / Hazard	Team Assessment			Risk Type HSE (H) Economic (E)	Comments & Control Measures
		I	P	E		
Low (limited) ROP due to overloading the shakers	Insufficient shakers capacity	M	L	M	E	Use coarse shaker screens. Run desander & desilter continuously to control sand content of mud.
Excessive deviation	Well deviation from vertical > 1.5deg at 26" OH TD. Incorrect drilling parameters used or incorrect BHA	H	L	M	E	Standard 3 stabiliser packed assembly to be used from spud.
20" casing operations	Personnel exposure to slip/trips/falls and trapped fingers	M	H	M	H,E	Pre-task safety tool box talks required
20" casing operations	Unable to run to 20" casing to bottom, due to ledges, tight hole from swelling shale or doglegs.	M	M	M	E	Standard 3 stabiliser packed assembly to be used from spud. Wiper trip and viscous pill on bottom before running casing. Possible use of weighted mud displacement.
Low 20" leak-off	Poor 20" cement job, or unusually low strength of Lower Alabaster Shale	M	H	M	E	Possible remedial squeeze.
Mixing cement	Personnel exposed to operations, manual handling of products, and COSHH requirements	L	H	M	H,E	Pre-task safety tool box talks required and PPE/MSDS at site
Poor cement job	Losses during cement job and poor cement seal at the shoe	L	L	L	E	Perform remedial cement squeeze at shoe. Perform top job if no cement back to surface.
Major Topic	**17 ½" hole**					
Picking up 17-1/2" hole BHA	Personnel exposure to slip/trips/falls and trapped fingers	M	H	M	H,E	Pre-task safety tool box talks required

Risk Title	Description of Risk / Hazard	Team Assessment			Risk Type HSE (H) Economic (E)	Comments & Control Measures
		I	P	E		
Losses in 17-1/2" hole	Losses induced or due to weak formations	M	H	M	E	In case of partial losses, follow LCM-pill procedures in mud programme. In case of total losses, drill blind with water and high-viscosity sweeps.
Reactive shales	Packing-off of annulus, reduced penetration rates	L	M	M	E	Maintain mud properties for optimum hole cleaning, maintain inhibitive properties (KCl and PHPA)
Tight hole on trips	Back reaming and pumping out as necessary causing excessive trip times	M	M	M	E	Ensure mud properties adequate for hole stability and hole cleaning.
Mud Mixing	Personnel exposed to operations, manual handling of products.	L	H	M	H,E	Pre-task safety tool box talks required and PPE/MSDS at site
13-3/8" casing operations	Personnel exposure to slip/trips/falls and trapped fingers	M	H	M	H,E	Pre-task safety tool box talks required
13-3/8" casing operations	Unable to run 13 3/8" casing to bottom, due to tight hole eg swelling shale, ledges, dog legs etc.	L	L	M	E	Standard 3 stabiliser packed assembly to be used. Wiper trip before running casing.
Mixing Cement	Personnel exposed to operations, manual handling of products.	L	H	M	H,E	Pre-task safety tool box talks required and PPE/MSDS at site
Poor cement job	Losses during cement job and poor cement seal at the shoe and over sands	L	L	L	E	In case of poorly cured losses in Sui Main consider two stage cement job

Risk Title	Description of Risk / Hazard	Team Assessment			Risk Type HSE (H) Economic (E)	Comments & Control Measures
		I	P	E		
Casing shoe set at the wrong depth and/or in poor formation.	Shoe inadvertently set in a sandstone / weak formation	M	M	M	E	Ensure that shale has been penetrated by at least 30 metres before setting casing.
Inadequate LOT	LOT less than required to drill the next section within kick tolerance policy	M	M	M	E	Perform remedial cement squeeze at shoe.
Major Topic	**12 1/4” hole**					
Picking up 12 1/4” hole BHA	Personnel exposure to slip/trips/falls and trapped fingers	M	H	M	H,E	Pre-task safety tool box talks required
Unable to drill ahead due to insufficient kick tolerance	Kick tolerance reduces below policy	M	L	M	E, H	Unlikely, based on known fracture strengths in area. Remedial squeeze if low LOT.
Hole cleaning	Poor hydraulics, mud properties and practices	M	L	M	E	Maintain mud properties as per programme.
Mud Mixing	Personnel exposed to operations, manual handling of products.	L	H	M	H,E	Pre-task safety tool box talks required and PPE/ MSDS at site
Unable to set 9-5/8” casing on bottom.	Unable to run to bottom due to tight hole eg swelling shale, doglegs, ledges etc.	L	M	M	E	Standard 3 stabiliser packed assembly to be used. Wiper trip before running casing.
Mixing Cement	Personnel exposed to operations, manual handling of products.	L	H	M	H,E	Pre-task safety tool box talks required and PPE / MSDS @ site

Risk Title	Description of Risk / Hazard	Team Assessment			Risk Type HSE (H) Economic (E)	Comments & Control Measures
		I	P	E		
Poor cement job	Losses during cement job and poor cement seal at the shoe and in permeable zones.	M	M	M	E	Perform remedial cement squeeze after drilling shoe.
Problems running Wireline logs	Unable to run to bottom. Hole problems eg ledges, cuttings beds. Tool failure.	M	M	M	E,H	Clean-up trip. Thoroughly QC tools prior to job. Have logging crew at location 48 hrs early.
Inadequate LOT	LOT less than required to drill the next section within kick tolerance policy.	H	L	M	E	Perform remedial cement squeeze at drilling shoe.
Losses	Losses induced to weak formations, a fault, poor drilling practices.	M	L	M	E	No faults evident on 3D seismic. No known cases of losses due to weak formations. Ensure that hole cleaning is adequate and annular cuttings load is controlled.
Tight Hole	Back reaming and pumping out of the hole is necessary causing excessive time on trips. Swabbing trying to POOH. Excessive resistance RIH	M	L	M	E	High quality KCl/PHPA/Glycol mud system with minimum density has been successful in mitigating this risk.
Unable to run casing to TD	Tight hole due to swelling	H	M	H	E	See above. Make wiper trip after logging, prior to running casing.
9-5/8” casing operations	Personnel exposure to slip/trips/falls and trapped fingers	M	H	M	H,E	Pre-task safety tool box talks required and PPE/ MSDS at site
Major Topic	**8 1/2” hole**					

Risk Title	Description of Risk / Hazard	Team Assessment			Risk Type HSE (H) Economic (E)	Comments & Control Measures
		I	P	E		
Losses in 8 ½" hole	Could cause well control problems	M	L	M	E, H	Maintain adequate concentration of bridging agents in mud system. Additional LCM to be available on rig site.
Unable to drill ahead due to insufficient kick tolerance	Kick tolerance reduces below policy	M	L	M	E, H	Unlikely, based on known fracture strengths in area. Remedial squeeze if low LOT. Evaluate situation, perform HAZID and seek dispensation from policy if abnormal pressures are encountered. Policy dispensation to be obtained.
Difficulties while tripping	Washouts, ledges, spiraling.	M	H	M	E	Use 3 stabiliser packed assembly to minimise tendency to spiral. Ream all ledges. Maintain mud weight above 11.0 lb/gal to prevent hole enlargement in over pressured, tight sands.
Picking up 8 1/2" hole BHA	Personnel exposure to slip/trips/falls and trapped fingers	M	H	M	H,E	Pre-task safety tool box talks required. Wear PPE.
Mud Mixing	Personnel exposed to operations, manual handling of products.	L	H	M	H,E	Pre-task safety tool box talks required and PPE / MSDS @ site
Washouts, poor OH geometry	Poor logs, unable to obtain RFT data	M	M	M	E	Maintain mud weight as per programme.
Abrasive formation	Early bit gauge damage; tight hole on following runs, BHA damage	H	H	M	E	Use diamond dressed gauge and heel TCI bits. Consider use of hard formation roller reamers.

Risk Title	Description of Risk / Hazard	Team Assessment			Risk Type HSE (H) Economic (E)	Comments & Control Measures
		I	P	E		
Hard formation	Low ROP	H	H	M	E	PCD bits available. Optimised drilling parameters.
H_2S in reservoir	Safety. Problems with mud; drop in pH; drill string corrosion, embrittlement.	L	L	M	E, (H)	Low probability. No H2S seen in area during drilling. Run the mud with increased pH and monitor closely. Sulphide scavengers to be available on rig site.
CO_2 in reservoir	Problems with mud; drop in pH; drill string corrosion. Dramatic increases in mud yield point and gel strengths.	L	L	M	E	Run the mud with increased pH and monitor closely. Calcium ion source to be available on rig site. Maintain calcium ion concentration above soluble calcium level.
Major Topic	**Logistics / Environmental Conditions**					
Excessive environmental temperatures / conditions.	Plant /equipment/material /personnel affected with environmental conditions.	VH	H	H	E,H	Ensure all vehicles /personnel are inspected /briefed /equipped on / for local environmental conditions.
Material Handling / Hazardous Goods	Transportation and manual / mechanical handling of hazardous goods /dangerous goods to and from well site.	VH	H	H	E,H	Trained operators / inspected. Supervised loading /unloading operations. Vehicles loads secured /not over weight. MSDS on all vehicles with hazardous /toxic material. Driver safety tool box talks held prior to travel.

Risk Title	Description of Risk / Hazard	Team Assessment			Risk Type HSE (H) Economic (E)	Comments & Control Measures
		I	P	E		
Documentation Control & Security Clearances	Failure to obtain necessary documentation /custom clearances for plant /equipment /materials /personnel	H	M	M	H,E	In-house procedures in place. All documentation / contractors documentation routed Logistics' Manager. Early mobilisation procedures in place. Contractor meetings held.
Water Shortages	Loss or short supply to potable /drill water requirements.	VH	M	H	H,E	Early mobilisation of water tankers & contingency procedure in place for hiring extra tankers. Poor water purity / DC to inspect regularly well site water transportation /supplies for purity. Regular site inspections of equipment and early orders of supply.
Communication failure	Failure of communications between rig site and office.	H	M	L	E	V-Sat system to be installed with separate satellite phone and independent power supply. HF Radio to be installed at rig and in office.

10. Details of all environment and safety related documentation within the company (regarding Life of pipeline, Corrosion prevention method, inspection etc.) in the form of guidelines, manuals, monitoring programmes including Occupational Health Surveillance Programme etc.

The environment and safety related documentations, pipeline integrity management system (PIMS) is enclosed as **Annexure-II *(enclosed with this report)*.**

The Occupational Health surveillance programme shall be in line with-

- API RP-54_- Occupational Safety & Health for Oil and Gas well drilling and servicing and
- Occupational health monitoring OISD Std-166.

The requirement will be finalized during the design & engineering stage of the development.

Applicability of OISD Standards: The equipments and utilities to be involved in the overall drilling tasks and their applicable standards are mentioned below:

Platform and Pipeline to be included

Sl. No.	Equipments	Verification Requirements	Reference Standards
1.	Drilling structure, Derick floor, sub structure, lifting equipment.	A. Derrick / Structures i. Structures have been designed and fabricated by manufacturers as per API Spec 4F or equivalent. This verification should include structural safety level (refer sections 6 and B.6 of API Spec 4F).	API Spec 4F (3rd Edition 2008)
		ii. Different categories' inspection(s) of derrick, structures and drill floor have been carried out as per section 6 of API RP 4G or equivalent and OEM's recommendations, besides Non-Destructive Examination (NDE) as considered necessary.	API RP 4G (3rd Edition, 2004)
		iii. Repair and modification of structures (if carried out, based on inspection) have been carried out as per section 7 and 8 respectively of API RP 4G or equivalent and OEM's recommendations. Quality control of repair and modification has been ensured in line with requirements of section 11 of API SPEC 4F or equivalent.	API RP 4G(3rd Edition, 2004) API Spec 4F (3rd Edition 2008)
		B. Drilling equipment i. Installation, inspection and maintenance of IC engines have been carried out as per API Spec	API Spec 7C-11F (5th Edition 1994)

Sl. No.	Equipments	Verification Requirements	Reference Standards
		7C-11F or equivalent and OEM's recommendations. For minimizing potential fires and/or explosions in the operations of IC engines requirements given in Appendix A of API Spec 7C-11F or equivalent, are being followed. Functional testing of safety devices and emergency stop function has been carried out.	
		ii. Design, inspection and operating limits of drill stem components is as per API RP 7G or equivalent.	API RP
		iii. Design of drilling equipment (rotary equipment, slush pumps, power tongs and draw works) is as per API Spec 7K or equivalent.	7G API Spec 7K
		iv. Inspection, maintenance and repair of rotary equipment, slush pumps, power tongs and draw works has been carried out as per API RP 7L or equivalent and OEM's recommendations. Inspection has included NDE and/or opening of equipment as considered necessary. Functional testing of safety devices and emergency stop function has been carried out.	API RP 7L
		v. Design of drilling hoisting equipment is as per API Spec 8A and API Spec 8C or equivalent	API Spec 8A and API Spec 8C.
		vi. Inspection, maintenance and repair of hoisting equipment are as per API RP 8B or equivalent and OEM's recommendations. Inspection of hoisting equipment has focused on structural integrity and personnel protection. Category III and IV inspection has included NDE / MPI and/or opening of equipment as considered necessary. Functional testing of safety devices and emergency stop function has been carried out.	API RP 8B
		vii. Minimum requirements and terms of acceptance of steel wire ropes as per API Spec 9A / ISO 10425 or equivalent are being followed.	API Spec 9A / ISO 10425
		viii. Field care (inspection) and use of wire rope and evaluation of rotary drilling line has been carried out as per API RP 9B or equivalent.	API RP 9B

Sl. No.	Equipments	Verification Requirements	Reference Standards
		ix. Inspection of piping and piping systems has been carried out as per API RP 570 and API RP 574.	API RP 570
		x. Pressure vessels have been inspected externally and internally; thickness measurement / crack detection tests have been carried out as deemed necessary. Pressure testing at a pressure equal to maximum allowable working pressure has been carried out. Safety valves / instrumentation have been tested.	API RP 574
2.	Well Control Systems: blow out preventers, diverters, marine risers, choke and kill system, control systems for well control equipment.	A. Design of drill through equipment / blowout prevention equipment – ram and annular blowout preventers, hydraulic connectors, drilling spools, adaptors etc. is as per API Spec 16A / ISO 13533 or equivalent. Records of maintenance (including major inspection as per section 17.10.3 of API RP 53 and OEM's recommendations) have been reviewed. Installation and testing (complete performance testing including functional and pressure tests) of blow out control equipment is being carried out in line with API RP 53 or OISDRP- 174 or equivalent.	API Spec 16A (3rd Edition 2004) / ISO 13533 (2001)
		B. Design and maintenance of diverter systems is as per API RP 64 or equivalent. Inspection and testing of diverter systems has been carried out as per API RP 64 or OISD-RP- 174 or equivalent.	API RP 53 (3rd Edition 1997) or OISD-RP-174 API RP 64 or OISD-RP-174
		C. Design of choke and kill systems are as per API Spec 16C or equivalent. Pressure testing of choke and kill systems is being carried out in line with API RP 53 or OISD-RP-174 or equivalent. Flexible choke and kill lines and choke manifold are inspected as per section 17.10.3 of API RP-53(3rd Edition 1997) and OEM's recommendations.	API Spec 16C API RP 53(3rd Edition 1997) or OISD-RP-174
		D. Design of control systems for well control equipment and diverter equipment is as per API Spec 16D and API RP 53 or equivalent and performance requirements/ testing, inspection and maintenance is as per API RP 53 or OISD-	API Spec 16D and API RP 53 API RP 53 or OISDRP-174 API RP 16Q

Sl. No.	Equipments	Verification Requirements	Reference Standards
		RP-174 or equivalent and OEM's recommendations.	
		E. Marine drilling riser systems for floating drilling operations have been selected, operated and maintained in line with API RP 16Q or equivalent. Design, manufacture and fabrication of marine drilling riser system and associated equipment used in conjunction with a subsea blowout preventer (BOP) stack are as per API Spec 16F or equivalent. Design and standards of performance for marine drilling riser coupling is as per API Spec 16R or equivalent. Risers and riser couplings / joints are being inspected for wear, cracks and corrosion; thickness measurement has been carried out as required.	API Spec 16F / API Spec 16R
3.	Man riding equipment	Selection of man riding equipment is done ensuring that equipment is suitable for man riding operations, and the equipment are inspected and maintained regularly.	
4.	Drilling fluid handling and cementing system	Physical condition of the equipment is satisfactory and instrumentation, safety alarms and pressure safety valves are being tested regularly.	
5.	Electrical Systems	A. Design and maintenance of electrical systems is as per IMO MODU code meeting requirements of industry standards API RP 500 or API RP 505. B. Inspection and functional testing of emergency power system is being carried out.	MODU code API RP 500 API RP 505
6.	Safety systems (exclude items which are covered by MODU safety certificate, provided the rig has valid MODU safety certificate	A. Inspection and testing of the following safety systems is being carried out periodically: − Fire detection system − Gas detection system – HC and H2S − Drilling operations related alarm system − Lifesaving appliances − SCBA − Gas measuring devices − Firefighting system − Communication systems B. Safety systems are as per MODU code requirements, as applicable.	

Sl. No.	Equipments	Verification Requirements	Reference Standards
7.	Cranes (If classed certificate notation does not cover cranes)	A. Design and testing of pedestal mounted offshore cranes are as per API Spec 2C or equivalent. B. Operations and maintenance of offshore cranes are as per API RP 2D or equivalent. Inspection has focused on structural integrity and includes: − Blocks and sheaves − Wire ropes and end attachments − Hooks − Bearings − Shackles − Securing arrangements − Support structure − Axle pin and housing C. Inspection and function testing has included: − Correct adjustment of brakes − Resistance measurement of electrical systems − Leakages in hydraulic systems D. Load charts have been verified by carrying out load tests as per applicable requirements. Functional testing of safety devices and emergency stop function are being carried out	API Spec 2C API RP 2D
8.	Helideck (If classed certificate notation does not cover helideck)	Inspection has included: − Structural integrity of deck and supporting structure − Surface of deck − Obstacles and marking − Safety net − Fire safety arrangements	

Other applicable OISD Standards:

Sl. No.	Requirements	Reference Standards
1.	Standard on Fire Fighting Equipment for Drilling Rigs, Work Over Rigs and Production Installations.	OISD-STD-189
2.	Inspection of Drilling and Workover Rig Mast / Sub-Structure.	OISD-GDN-202
3.	Guidelines for Safe Rig- Up and Rig- Down Of Drilling And Work Over.	OISD-GDN-218
4.	Inspection of Piping Systems	OISD-STD-130
5.	Inspection of pipelines Offshore	OISD-STD-139

Sl. No.	Requirements	Reference Standards
6.	Well Control	OISD-RP-174
7.	Safe Practices for Workover & well Stimulation Operations	OISD-GDN-182
8.	Oil Field Explosive Safety	OISD-STD-191
9.	Safety Practices During Construction	OISD-GDN-192

ANNEXURE – I

- Documents of Vessel,
- ODAG Clearance Document
- Credential of Personnel involved in sample collection.
- Vessel Inspection Pictures
- GPS data log of sampling route and location.

Sampling Vessel for baseline monitoring (Phalguni Boat).

Sampling Vessel for baseline monitoring.

MAHARASHTRA GOVT. INS. FUND MUMBAI DIRECTORATE OF INS.

सत्यमेव जयते

Maharashtra Government Insurance Fund

Office :- Directorate of Insurance, Griha Nirman Bhavan MHADA Opp Kalanagar Bandra (E) Mumbai 400051
Phone No.Director-022-26591782, Office-022-26590690/26590746.FAX-022-26590403/26592461.

MARINE HULL POLICY

INSURANCE OF FISSHING VESSEL (TOTAL LOSS ONLY) AND P.A. COVER FOR CREW ON BOARD.

WHEREAS the ASSURED named in the policy hereto, have represented to MAHARASHTRA GOVERNMENT INSURANCE FUND[hereinafter called the ;FUND] that they are interested in or duly authorized to make the insurance mentioned and described and have paid or agreed to pay the premium hereinafter stated.

THE FUND HEREBY PROMISES AND AGREES with the Assured their Executors Administrators and Assigns that the FUND insures against loss, damage, liability or expense subject to the clauses, endorsements, conditions and warranties contained in this Schedule.

SCHEDULE 14 MAR 2018

Policy No **AIF 1217-MH- MUM-3707/ D.**

Name of the Assured :-1) The Asstt. Commissioner of Fisheries, Govt of Maharashtra, MUMBAI. 2)The Chairman, Mahim M.. V. K. Sah. Society Ltd. Mumbai.

3) **SHRI SUNIL NANA DHANMEHER,(+7)** Chinchani, Dande Pada, Tal-Dahanu, Palghar.

Name of the Fishing Vessel **"PHAIGUNI"** Regn.No.**IND- MH-2-MM-5322.**

Period of Insurance:- **12 Months,** From:- **14-03-2018 To 13-03-2019.**

Sum Insured Hull & Machinery Rs.**5,00,000/- (Rs. Five Lakhs Only.**)

P.A. Cover Rs.**1,00,000/-**per crew. Total No. of Crew: **10 (Ten)**

INSURANCE	Net Premium	GST@ 9%	GST @9%	Stamp Duty	Total Premium
H & M/P.A. Rs.	13663/-	1230/-	1230/-	125/-	**16248/-**

Mode of Payment:- Paid Rs. **16248/-** Vide Consolidated GRAS Amount Rs. **32496**/-on dt.14.03.2018.

Conditions:-1. Risk if fishing vessel subject to IFVC, Dated 20th July 1987 but limited to pay only TL/CTL (including salvage, salvage charges Sue & labour) C.R.O.

2. P.A. Cover for crew member on board the fishing vessel are covered as per benefits stated below.

	Death.	100%
	Loss of two limbs or sight of two eyes or one limb and one eye.	100%
	Loss of one limb or sight of one eye.	50%
	Permanent total disablement from injuries other than named above.	100%

Trading Warranty:- Warranted vessel engaged in fishing and operation connected there with on the coast of Gujrat, Maharashtra & Goa with leave to proceed upto Karwar and not beyond 50 Nautical Miles in to the sea from shore. Warranted vessel laid-up from 1st June to 31 July (B.D.I.) with leave to operation o;n coast of Saurashtra and Kutch during this period.

Notice of loss:- In the event of loss or damage which may involve a claim under this insurance, immediate notice thereof and application for survey should be given to the office mentioned above.

IN WITNESS WHERE OF signed for and on behalf of the fund.

GSTIN-27AAAGD0308P1ZH

Asstt./Deputy Director of Insurance,
Maharashtra State Mumbai.

Junior Technical Officer,
Maharashtra State Mumbai.

Insurance Papers of Boat (Phalguni Boat).

Government of India

Form IV

Merchant Shipping (Registration of Indian Fishing Boats), Amendment rules 1988

(See sub rule(2) of Rule 7)

Certificate of Registry of a Fishing Boat

State: MAHARASHTRA

1. Name of Fishing Boat : **PHALGUNI**
2. Registration Number & Date (मासेमारी नौका नोंदणी कमांक व दिनांक) : **IND-MH-2-MM-5322 & 28/03/2010**
3. Call Sign (Where Applicable) : - -
4. Port & District where Registered (नोंदणीचे बंदर आणि जिल्हा) : KHARDANDA & MUMBAI SUBURBAN : (खारदांडा,मुंबई उपनगर)
5. Name of the Owner Permanent Residence or Principal Place of Business. : SHRI. SUNIL NANA DHANMEHER. (+7) CHINCHANI, DANDE PADA, TAL-DAHANU, DIST-THANE.

Shares Held (%) : 14.28

Aadhaar (UID) : - -

Coastal Security Number : - -

6. Category of Ownership : Society
7. Area of Operation (कार्यचालनाचे क्षेत्र) : As prescribed in Merchant Shipping Act 1958 (MS Act)
8. Particulars of Fishing Boat (मासेमारी नौकेचा तपशिल)

i) Name & Address of Building Yard (नौका बांधकामाचे ठिकाण व पत्ता) : CHINCHANI, DANDE PADA, DAHANU. : (- -)

ii) Year of Build/Rebuild of the Boat (नौका बांधकामाचे किंवा पुर्नबांधणीचे वर्ष)	iii) Hull Material (नौकेचे दल लाकूड किंवा इतर प्रकार)	iv) Length(Mtrs) (लांबी मीटर)	v) Breadth(Mtrs) (रुंदी मीटर)	vi) Depth(Mtrs) (ऑडी मीटर)
2007	Wood/लाकूड	19.100	6.096	1.829

vii) Engine details (इंजिनाचा तपशिल)

Make	Ashok Leyland
Year of Make	- -
Engine Number	YFEM-67037
HP	106
Name and Address of Manufacturer	- -
Number & Diameter of Cylinders	6 &
Length of Stroke	- -

AA042852

Revolution per minute(RPM)/Speed	2000
Fuel Used (Capacity in Ltrs) (इंधन वापर इंधन क्षमता)	: Diesel(2000)
viii)Type of Vessel (नौकेचा प्रकार)	: In board Engine Fitted Craft : यांत्रिक नौका
ix)Number of Masts/Bulk Heads/Holds	: 2 / /
x)Tonnage Capacity (Gross Tons) (टनेज ग्रॉस)	: 47.02
xi)Fishing Gear (मासेमारीचे अवजार)	: - - : - -

9. Communication Equipment

Name of the Equipment	Device Number	Make & Model
-	-	-

10. Life Saving Appliances
Name of the Equipment : LIFE JACKETS,Life Buoy,RIGID LIFE RAFT.

11. Number of Crew : (खलाशी संख्या) :6

12. Base of Operation (मासेमारीचे मूळ बंदर) : DAHANU : (डहाणू)

Place : KHARDANDA
Date : 16/09/2013

OFFICE OF THE PORT OFFICER & REGISTRAR BANDRA GROUP OF PORTS MUMBAI-400 052.

Signature and Seal of Registering Authority
PORT OFFICER
REGISTRAR
Bandra Group of Ports
Mumbai - 400 052.

Conditions of the Certificate of Registration

1. This certificate of registration is granted under the provisions of Merchant Shipping Act 1958, as amended.
2. Any change in the fishing boats,name,other markings,layout,design,capacity of the vessel should be effected only with the prior approval of the registration authority.
3. The certificate must be produced for inspection on demand by any authorised person.
4. Should the vessel be lost, broken up or rendered unfit for service, this certificate should be surrendered to the Registrar of the Fishing Boat.

IT Support By National Informatics Centre

Phalguni boat Registration Document.

INMARSAT : NA
PHALGUNI/FCB/IFIC/ADNI/1186/080518/060618, VALID TILL 06 JUN 18

HEADQUARTERS OFFSHORE DEFENCE ADVISORY GROUP

15TH FLOOR, F – WING
MAKER TOWERS
CUFFE PARADE
MUMBAI – 400 005
TEL: 91-22-22181424
FAX: 91-22-22151906

FROM :	HQODAG	
TO :	ADANI WELSPUN EXPLORATION LTD	: 2490 8020
INFO :	COMCG (W) / CSO (OPS)	: 2433 3727
	CHANDRA SHIPPING	: 2261 8138
FILE :	OP/0103/NSC	: 09 MAY 18

NAVAL SECURITY CLEARANCE – PHALGUNI

1. THE NAVAL SECURITY TEAM INSPECTED **PHALGUNI** AT **PALGHAR** ON **08 MAY 18** AND CLEARED THE CHASE BOAT TO CARRYOUT **CONDUCTING EIA STUDY.** THE VESSEL IS SECURITY CLEARED AND THE SECURITY CLEARANCE NUMBER IS **FCB/IFIC/ONGC/1312/151216/301216.** THE SECURITY CLEARANCE IS ISSUED FOR THE OPERATIONS IN **BLOCK/MB/OSDSF/B9/DSF (B9) CLUSTER OFF WEST COAST** AND IS **VALID TILL 06 JUN 18 (AS PER RSEE & PASS).** THE VESSEL IF FOUND OPERATING BEYOND THE PERMITTED PERIOD OR OPERATING UNAUTHORIZED WOULD BE LIABLE TO BE IMPOUNDED BY THE LOCAL NAVAL/ COAST GUARD AUTHORITIES.

2. THE VESSEL IS TO OPERATE IN THE EEZ IN ACCORDANCE WITH THE PROVISION OF TERRITORIAL WATERS, CONTINENTAL SHELF, EXCLUSIVE ECONOMIC ZONE AND MARITIME ZONES ACT, 1976 AND OTHER EXISTING RULES AND REGULATIONS IN FORCE.

3. THE VESSEL IF FOUND VIOLATING ANY OF THE PROVISION OF TERRITORIAL WATERS, CONTINENTAL SHELF, EXCLUSIVE ECONOMIC ZONE AND MARITIME ZONES ACT, 1976 OR ANY OTHER LAW IS LIABLE TO BE PROSECUTED FOR ACTS PREJUDICIAL TO THE INTEREST AND SECURITY OF THE COUNTRY FOR EXAMPLE ESPIONAGE, SPYING, THEFT ETC.

4. THE VESSEL DETAINED FOR VIOLATING THE EXISTING RULES AND REGULATIONS AND LEGISLATIONS ENACTED UNDER SUCH ACTS ARE LIABLE TO BE ESCORTED TO THE NEAREST PORT AND DETAINED TILL INVESTIGATIONS ARE COMPLETED OR FRESH CLEARANCE IS ACCORDED AT THE OPERATOR/ OWNERS COST.

5. THE VESSEL SHALL NOT ENGAGE IN ANY SURVEY OR DATA COLLECTION ACTIVITIES. THE VESSEL IS TO QUOTE THE ABOVE NSC NUMBER DURING INTERROGATION BY INDIAN NAVAL/ COAST GUARD AUTHORITIES. IT MAY PLEASE BE NOTED THAT YOU WILL BE REQUIRED TO PRESENT THIS VESSEL FOR RE-INSPECTION BY INDIAN NAVAL AUTHORITIES AS AND WHEN REQUIRED AND ON THE FOLLOWING OCCASIONS:-

(A) ON COMPLETION OF ANY REPAIRS AND CHANGE IN EQUIPMENT STATUS.

(B) ON RETURN FROM ANY PORT OUT SIDE INDIA.

6. YOU ARE REQUIRED TO PROVIDE PRIOR INTIMATION TO THIS HEADQUARTERS OF OCCURRENCES INDICATED BELOW:-

(A) THE VESSEL LEAVING FIELD FOR PASSAGE TO ANY PORT OUTSIDE INDIA.
(B) ON LEAVING THE AREA OF OPERATIONS FOR OPERATIONAL TURN AROUND.
(C) AS AND WHEN ANY CREW CHANGE TAKES PLACE.
(D) AS AND WHEN VESSEL IS OFF HIRED.

PHALGUNI/FCB/IFIC/ADNI/1186/080518/060618, VALID TILL 06 JUN 18

QODAG
Date ....
MUMBAI

Fardy

INMARSAT : NA

PHALGUNIFCB/IFIC/ADNI/1186/080518/060618, VALID TILL 06 JUN 18

-2-

(E) NO THURAYA, IRIDIUM AND OTHER SUCH SATELLITE PHONES ARE TO BE HELD ONBOARD, BOTH BY THE VESSELS AND CREW. ANY VIOLATORS ARE LIABLE TO BE PROSECUTED UNDER SECTION 6 OF INDIAN WIRELESS ACT AND SECTION 20 OF INDIAN TELEGRAPH ACT.

7. NON RECEIPT OF SUCH INTIMATION WILL RESULT IN IMMEDIATE CANCELLATION OF NAVAL SECURITY CLEARANCE AND ACTION TO REMOVE THE VESSEL FROM THE AREA OF OPERATION.

8. THE VESSELS IF FITTED WITH AIS (AS PER IMO REGULATION) AND OPERATING IN THE ODAs, ARE TO ENSURE THE FOLLOWING: -

(A) DATA INPUT IN THE AIS IS CORRECT.

(B) AIS IS OPERATIONAL AND KEPT SWITCHED ON AT ALL TIMES.

(C) INFORM HQ ODAG BY FAX/ FASTEST MEANS AVAILABLE, IF AIS IS NON OPERATIONAL GIVING REASONS AND TIME BY WHICH IT WOULD BE OPERATIONALISED.

9. YOU ARE FURTHER REQUESTED TO: -

(A) INCLUDE THE PARTICULARS AND INFORMATION OF THIS VESSEL IN YOUR DAILY PROGRESS REPORT TO THIS HEADQUARTERS AND MOC (MUMBAI) FAX NO. 022 – 22661702 AS PER THE FORMAT HANDED OVER BY THE NAVAL TEAM AT THE TIME OF INSPECTION.

(B) KEEP LOCAL NAVAL AUTHORITY / HQ ODAG INFORMED REGARDING TASK COMPLETION AND LEAVING OF DEPLOYMENT AREA.

(C) ADVISE THE VESSEL TO MONITOR NAVAREA VIII WARNINGS / METEOROLOGICAL WARNINGS AND FORECASTS. MAKE INSPIRE/ INDSAR REPORTS.

(D) ENSURE THAT NO FOREIGN PERSONNEL ARE EMPLOYED ON BOARD THE VESSEL. IF REQUIRED MOD AND MOHA/ IB CLEARANCE BE OBTAINED PRIOR TO DEPLOYMENT. A COPY OF THE SAME BE FORWARDED TO THIS HEADQUARTERS FOR RECORD.

(E) LIAISE WITH THIS HEADQUARTERS FOR ISSUANCE OF NAVAREA INDICATING DETAILS OF TASK BEING UNDERTAKEN BY IT AND THE SAFETY PRECAUTION REQUIRED TO BE ADHERED TO BY VESSELS TRANSITING THROUGH THE AREA.

(F) EXERCISE CAUTION WHILE OPERATING AT SEA AS A LARGE NUMBER OF SURVEY VESSELS ARE EMPLOYED FOR SEA-BED SURVEY, SEISMIC SURVEY, GEOPHYSICAL SURVEY ETC ARE OPERATING IN THE AREA, DETAILS OF THESE VESSELS ARE BEING PROMULGATED THROUGH NAVAREA WARNINGS.

10. REGULAR PATROLLING IS BEING CARRIED OUT BY INDIAN NAVY/COAST GUARD SHIPS AND AIRCRAFT IN THE ODAs. THESE VESSELS MAY BOARD & CARRY OUT SURPRISE INSPECTION OF THE VESSEL & CREW AT ANY TIME DURING THE COURSE OF CONTRACT. ALL VESSELS ARE TO PROMPTLY ACKNOWLEDGE AND RESPOND TO THEIR CALLS, STOP IF REQUIRED AND ENSURE STRICT COMPLIANCE WITH THEIR INSTRUCTIONS. IF BOARDED, THEY ARE TO TAKE ALL MEASURES TO FACILITATE SAFE BOARDING AND PROVIDE FULL COOPERATION AS REQUIRED FOR THE INSPECTION OF THE VESSEL/ PRESENTATION OF DOCUMENTS.

(SG PANDA)
COMMODORE
CSO & PD (OPS)
FOR FLAG OFFICER

PHALGUNIFCB/IFIC/ADNI/1186/080518/060618, VALID TILL 06 JUN 18

ODAG Clearance Documents.

ODAG Inspection Pictures.

Credentials of Personnel involved in the Sea Monitoring

ID PASSES FOR MOTOR FISHING BOAT PHALGUNI

Operator Name :	**ADANI WELSPUN EXPLORATION LIMITED**
Sub-Contractor Name	**ASIAN CONSULTING ENGINEERS PVT LTD**
Project Operations	
SECUIRITY PASS VALID UP TO	**FROM**

SR NO.	NAME	RANK	NATIONALITY	DOB	AADHAR NO / FISHER ID	AADHAR NO / FISHER ID VALIDITY	CDC NO.	CDC VALIDITY	PASS NO.	PHOTO
VESSEL CREW										
1	ULHAS JAGANNATH MEHER	TANDEL	INDIAN	16-Aug-1958	MH04 TF 29988 8	PMT	NA	NA		
2	AJIJ AMRUDDIN SHAIKH	CREW	INDIAN	08-Jun-1987	8819 0072 5377	PMT	NA	NA		
3	PRALHAD VASANT TARE	CREW	INDIAN	01-Jun-1963	MH04 TF 16108 8	PMT	NA	NA		
4	MILAN BHANUDAS PATIL	CREW	INDIAN	01-Dec-1960	MH04 VC 09494 5	PMT	NA	NA		
5	KAMALAKAR NARAYAN DEV	CREW	INDIAN	01-Jan-1974	3917 3963 6526	PMT	NA	NA		
6	KOUSHIK MUKHOPADHYAY	SR. PROJECT EXECUTIVE	INDIAN	05-Nov-1986	8649 8234 5656	PMT	NA	NA		

1) Certified that all the above person, have undergone all the mandatory offshore safety trainings.
2) The personnel supporting documents have been verified and found in order and recommended for issue of passes.
3) Deployment of above personnels is necessary for execution and operation of the contract.

Name:	Abhaye Mahajan
Designation:	Managing Director
Place:	New Delhi
Date:	04.05.2018

भारत सरकार
GOVERNMENT OF INDIA

अजीज अमरुद्दीन शेख
Ajij Amruddin Shaikh
जन्म तिथि/ DOB: 08/06/1987
पुरुष / MALE

8819 0072 5377

आधार-मेरा आधार, मेरी पहचान

AADHAAR

भारतीय विशिष्ट पहचान प्राधिकरण
UNIQUE IDENTIFICATION AUTHORITY OF INDIA

पता:
आत्मज: अमरुद्दीन शेख,
456, ब्रम्हाणी पाडा,
सातपाटी, तालुका-पालघर,
जिल्हा-पालघर, सातपाटी,
पालघर,
महाराष्ट्र - 401405

Address:
S/O: Amruddin Shaikh, 456,
Bramhani Pada, Satpati, Taluka-
Palghar, Dist-Palghar, Satpati,
Palghar,
Maharashtra - 401405

8819 0072 5377

Aadhaar-Mera Aadhaar, Meri Pehachan

भारत सरकार
GOVERNMENT OF INDIA

कमळाकर नारायण देव
Kamalakar Narayan Dev
जन्म तिथि/ DOB: 01/01/1974
पुरुष / MALE

3917 3963 6526

आधार-आम आदमी का अधिकार

भारतीय विशिष्ट पहचान प्राधिकरण
UNIQUE IDENTIFICATION AUTHORITY OF INDIA

पता:
S/O: नारायण सदू देव, वार्ड - ब, बाजार रोड, समता मंडल, सातपाटी, ठाणे, महाराष्ट्र - 401405

Address:
S/O: Narayan Sadu Dev, ward - B, bazar road, samata mandal, Satpati, Thane, Maharashtra - 401405

3917 3963 6526

Aadhaar-Aam Admi ka Adhikar

सत्यमेव जयते
भारत सरकार

आधार

ভারতীয় বিশিষ্ট পরিচয় প্রাধিকরণ
ভারত সরকার
Unique Identification Authority of India
Government of India

তালিকাভুক্তির আই ডি / Enrollment No. : 1040/20169/05277

To
Koushik Mukhopadhyay
কৌশিক মুখোপাধ্যায়
23/A
J. M.N.BOSE LANE
KONNAGAR
Konnagar (M)
Konnagar,Hooghly
West Bengal - 712235

23/03/2013

KL890063958FT
89006395

আপনার আধার সংখ্যা / Your Aadhaar No. :

8649 8234 5656

আধার – সাধারণ মানুষের অধিকার

ভারত সরকার
Government of India

কৌশিক মুখোপাধ্যায়
Koushik Mukhopadhyay
পিতা : সুভাষ চন্দ্র মুখোপাধ্যায়
Father : Subhas Chandra Mukhopadhyay

জন্মতারিখ / DOB: 05/11/1986
পুরুষ / Male

8649 8234 5656

सत्यमेव जयते
Government of India

AADHAAR

তথ্য

- আধার পরিচয়ের প্রমাণ, নাগরিকত্বের প্রমাণ নয়।
- পরিচয়ের প্রমাণ অনলাইন প্রমাণীকরণ দ্বারা লাভ করুন।

INFORMATION

- Aadhaar is proof of identity, not of citizenship.
- To establish identity, authenticate online.

- আধার সারা দেশে মান্য।
- আধার ভবিষ্যতে সরকারী ও বেসরকারী পরিষেবা প্রাপ্তির সহায়ক হবে।
- Aadhaar is valid throughout the country.
- Aadhaar will be helpful in availing Government and Non-Government services in future.

আধার

ভারতীয় বিশিষ্ট পরিচয় প্রাধিকরণ
Unique Identification Authority of India

ঠিকানা:, /এ
জাস্টিস. এম.এন বোস লেন, কোন্নগর
কোন্নগর (মিউনিসিপ্যালিটি), কোন্নগর
হুগলী, পশ্চিমবঙ্গ,

Address: 23/A, J. M.N.BOSE LANE, KONNAGAR,
Konnagar (M), Konnagar,
Hooghly, West Bengal,
712235

8649 8234 5656

3

इस पासपोर्ट में 36 पृष्ठ है। This passport contains 36 pages.

भारत गणराज्य REPUBLIC OF INDIA

टाईप / Type: P

राष्ट्र कोड / Country Code: IND

पासपोर्ट नं. / Passport No.: N9277072

उपनाम / Surname: MUKHOPADHYAY

दिया गया नाम / Given Name(s): KOUSHIK

राष्ट्रीयता / Nationality: भारतीय/INDIAN

लिंग / Sex: M

जन्मतिथि / Date of Birth: 05/11/1986

जन्म स्थान / Place of Birth: KOLKATA, WEST BENGAL

जारी करने का स्थान / Place of Issue: KOLKATA

जारी करने की तिथि / Date of Issue: 07/06/2016

समाप्ति की तिथि / Date of Expiry: 06/06/2026

Koushik Mukhopadhyay

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विविध सेवा / MISCELLANEOUS SERVICE

टिप्पणी / OBSERVATION

34

N9277072

पिता / कानूनी अभिभावक का नाम / Name of Father / Legal Guardian

SUBHAS CHANDRA MUKHOPADHYAY

माता का नाम / Name of Mother

JAYANTI MUKHOPADHYAY

पति या पत्नी का नाम / Name of Spouse

पता / Address

23/A,JUSTICE M.N BOSELANE

KONNAGAR,HOOGHLY

PIN:712235,WEST BENGAL,INDIA

पुराने पासपोर्ट का नं. और इसके जारी होने की तिथि एवं स्थान / Old Passport No. with Date and Place of Issue

फाईल नं. / File No.

CA2068838065515

भारत सरकार
कृषि मंत्रालय
समुद्री मछुआरा पहचान-पत्र

Government of India
Ministry of Agriculture
MARINE FISHERS IDENTITY CARD

MH04 VC 09494 5

जन्म तिथि
Date of Birth
01/12/1960

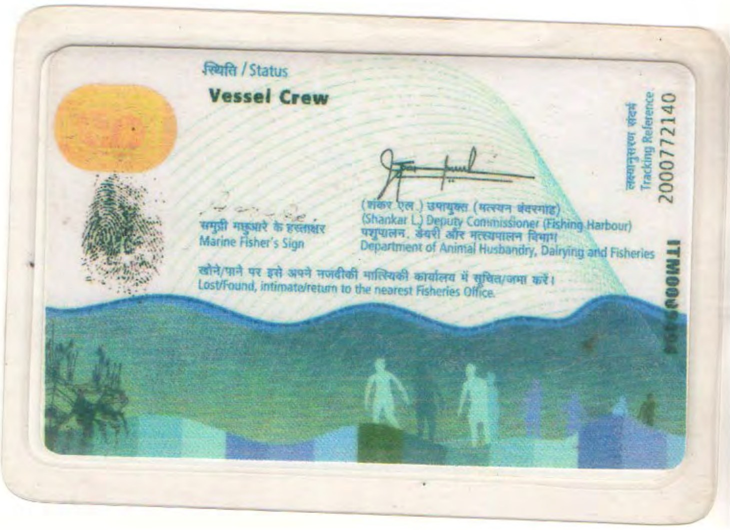
जारी करने की तिथि
Issue Date
07/04/2012

लिंग
Gender
M

राज्य/संघ राज्य क्षेत्र / State/UT
MAHARASHTRA

नाम / Name
मिलन भानुदास पाटील
MILAN BHANUDAS PATIL

पिता/माता/पति/पत्नी का नाम / Father/Mother/Spouse Name
भानुदास पाटील
BHANUDAS PATIL



स्थिति / Status
Vessel Crew

समुद्री मछुआरे के हस्ताक्षर
Marine Fisher's Sign

(शंकर एल.) उपायुक्त (मत्स्यन बंदरगाह)
(Shankar L.) Deputy Commissioner (Fishing Harbour)
पशुपालन, डेयरी और मत्स्यपालन विभाग
Department of Animal Husbandry, Dairying and Fisheries

खोने/पाने पर इसे अपने नजदीकी मात्स्यिकी कार्यालय में सूचित/जमा करें।
Lost/Found, intimate/return to the nearest Fisheries Office.

ट्रैकिंग संदर्भ
Tracking Reference
2000772140

ITM00

भारत सरकार
कृषि मंत्रालय
समुद्री मछुआरा पहचान-पत्र
सत्यमेव जयते

Government of India
Ministry of Agriculture
MARINE FISHERS IDENTITY CARD

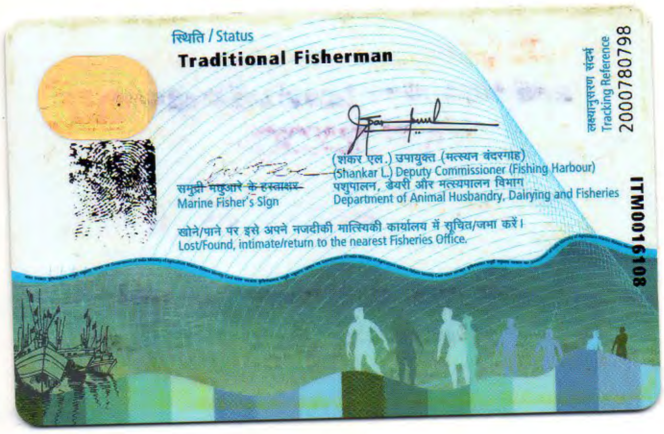
MH04 TF 16108 8

जन्म तिथि Date of Birth	जारी करने की तिथि Issue Date	लिंग Gender
01/06/1963	**07/04/2012**	**M**

राज्य/संघ राज्य क्षेत्र / State/UT
MAHARASHTRA

नाम / Name
प्रल्हाद वसंत तरे
PRALHAD VASANT TARE

पिता/माता/पति/पत्नी का नाम / Father/Mother/Spouse Name
वसंत तरे
VASANT TARE



स्थिति / Status
Traditional Fisherman

समुद्री मछुआरे के हस्ताक्षर
Marine Fisher's Sign

(शंकर एल.) उपायुक्त (मत्स्यन बंदरगाह)
(Shankar L.) Deputy Commissioner (Fishing Harbour)
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Department of Animal Husbandry, Dairying and Fisheries

खोने/पाने पर इसे अपने नजदीकी मात्स्यिकी कार्यालय में सूचित/जमा करें।
Lost/Found, intimate/return to the nearest Fisheries Office.

लक्ष्यानुसरण संदर्भ
Tracking Reference
2000780798

ITM0016108

भारत सरकार
कृषि मंत्रालय
समुद्री मछुआरा पहचान-पत्र

Government of India
Ministry of Agriculture
MARINE FISHERS IDENTITY CARD

सत्यमेव जयते

MH04 TF 29988 8

जन्म तिथि Date of Birth	जारी करने की तिथि Issue Date	लिंग Gender
16/08/1958	16/04/2012	M

राज्य/संघ राज्य क्षेत्र / State/UT
MAHARASHTRA

नाम / Name
उल्हास जगन्नाथ मेहेर
ULHAS JAGANNATH MEHER

पिता/माता/पति/पत्नी का नाम / Father/Mother/Spouse Name
जगन्नाथ नथुराम मेहेर
JAGANNATH NATHURAM MEHER

स्थिति / Status
Traditional Fisherman

5

समुद्री मछुआरे के हस्ताक्षर
Marine Fisher's Sign

(शंकर एल.) उपायुक्त (मत्स्यन बंदरगाह)
(Shankar L.) Deputy Commissioner (Fishing Harbour)
पशुपालन, डेयरी और मत्स्यपालन विभाग
Department of Animal Husbandry, Dairying and Fisheries

खोने/पाने पर इसे अपने नजदीकी मात्स्यिकी कार्यालय में सूचित/जमा करें।
Lost/Found, intimate/return to the nearest Fisheries Office.

अनुसरण संदर्भ
Tracking Reference
2000783634

ITM0029988

COLOUR XER


FURUNO GPS/WAAS NAVIGATOR
WPTS/MARKS (LIST)
[NEW?] 001 002
003 004 005
006 007 008
009 010 CURSOR
MOB START
MENU ENT
DISP GOTO
MARK MOB
GP-32
DIM PWR


GPS/WAAS NAVIGATOR
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NAME: 001
10-MAY 07:36 PM
MENU ENT
DISP GOTO
MARK MOB
GP-32
DIM PWR


GPS/WAAS NAVIGATOR
WPTS/MARKS (LIST)
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LOG RTE?
MENU ENT
DISP GOTO
MARK MOB
GP-32
DIM PWR


GPS/WAAS NAVIGATOR
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DISP GOTO
MARK MOB
GP-32
DIM PWR


FURUNO GPS/WAAS NAVIGATOR
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LOG RTE?
MENU ENT
DISP GOTO
MARK MOB
GP-32
DIM PWR


FURUNO GPS/WAAS NAVIGATOR
WPTS/MARKS (LIST)
NAME: 005
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11-MAY 07:12 AM
LOG RTE?
MENU ENT
DISP GOTO
MARK MOB
GP-32
DIM PWR

GPS Log Data Pictures

Location names	Coordinates	Time	Date
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2	20º 05.372'N 71º 26.236' E	7:03 AM	11-May
3	20º 01.478'N 71º 27.345'E	7:04 AM	11-May
4	19º 58.465'N 71º 40.470'E	7:06 AM	11-May
5	19º 53.364'N 71º 10.542'E	7:12 AM	11-May
6	20º 08.230'N 71º 21.427'E	2:20 PM	11-May
7	20º 05.378'N 71º 26.236'E	4:04 PM	11-May
8	20º 01.481'N 71º 27.344'E	5:15 PM	11-May
9	19º 58.344' N 71º 11.37.1'E	8:52 AM	12-May
10	19º 43.581'N 72º 42.110'E	4:01PM	13-May

GPS Data Log Sheet

ANNEXURE – II

- Guideline for Pipeline Integrity Management System (PIMS)

MB-OSDSF-B9/2016
B9 CLUSTER DEVELOPMENT

Document No.: AWEL-RX-B9 Cluster-PIMS-0001

Guideline For Pipeline Integrity Management System (PIMS)

1	07.05.2019	Issued for Project	LS	BG	AH
0	01.03.2018	Issued for review	LS	AS	AH
Rev	Date	Purpose of Issue	Prepared By	Reviewed By	Approved By

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1. INTRODUCTION

1.1 Background

The submarine pipeline system is required to transport fluids efficiently & safely both with regards to flow assurance as well as structural and containment functions. Pipelines carrying hydrocarbons fluids at pressure are a major hazard and require systematic management to avoid harm to people or damage to the environment. They are strategic assets that are critical to delivery of product to market as well as their continuing fitness-for-purpose is vital.

Integrity management is core responsibility of the company which through the Integrity Management (IM) Policy defines the management commitment to meeting the business objective whilst avoiding hazards that cause harm to people, the environment and property.

1.2 Purpose of PIMS

The overall purpose of this Pipeline Integrity Management System is to

a. Ensure continuation of pipeline integrity.
b. Ensure the availability of pipelines for operations.

1.3 Objective of PIMS

The objective of the Pipeline Integrity Management System is to:

a. Assure compliance with the IM Policy;
b. Define applicability to all company divisions involved in pipeline integrity;
c. Assure compliance with local legislation, shareholder and international regulations;
d. Define the Process (standards, practices and procedures) and records, which shall be complied with, to provide pipelines integrity assurance;
e. Define the key People - Integrity & Technical Authorities and their roles and responsibilities;
f. Define the Critical Records which shall be documented as part of the Integrity Management process;
g. Definition of the boundary that PIMS covers as defined under section 6.2.

1.4 Scope of PIMS

The scope include

a. Pipeline mechanical integrity management during design & construction, commissioning, operations, mothballing and decommissioning;

b. Elements of pipeline process safety management including hazards assessment, training and contractor management, management of change, incident investigation, emergency response and audits.

   This Guideline is intended to provide & highlights the minimum basic company requirements without relieving the contractors of their contractual obligations. Contractors would be required to obtain written approval from the company for any deviation from this Guideline.

1.5 Coverage of PIMS

The PIMS is the first point of reference for all involved in pipeline integrity across the company at all stages of the asset life cycle, from conceptual design to decommissioning. Its applicability extends to design engineers, installation engineers, operations personnel, and inspection & certification engineers including those working in the supply chain delivery.

PIMS applies to all pipeline activities of the company including major projects, brownfield projects, new fields projects, operations, maintenance, logistics and decommissioning both in the onshore and offshore environments.

1.6 References

1.6.1. General

The latest edition of the reference standards/ international recommended practices & documentation as listed in Appendix-N shall be read as an integral part of this Document.

1.6.2. Equivalent Standards

Standard documents equivalent to those referred to herein shall not be substituted without written approval from the company.

1.7 Abbreviations

The abbreviations normally used in this Guideline and relevant documents are listed in Appendix-L.

1.8 Definitions

The definitions used in this Guideline are listed in Appendix-M.

1.9 Lessons Learned

a. Upon completion of works related to the scope of this document, a descriptive summary of lessons learned shall be prepared and made available by the contractors/ consultants / company person-in-charge and to be made available as Lessons Learned Systems as appropriate.

b. The PIMS will only be effective if it is applied as part of a long-term continuous improvement programme revised and updated in line with any new strategies, changes to the business and lessons learned.

c. Trending information shall be used to help identify performance gaps in the PIMS process and to spot opportunities for improvement. Lessons learned that would require a change to PIMS may arise at any time and be initiated by anyone involved with PIMS. Recommendations shall be considered by Integrity Authority and acted upon as deemed appropriate by the TA (defined in the later sections).

d. Annual review of PIMS performance may be undertaken as needed in order to establish how well the PIMS objectives and targets have been met and to develop any required recommendations for improvement.

1.10 Local legislation

The national laws on protection of the environment & people are applicable in that the consequences of a major accident hazard may result in either adverse environmental impacts or effects on people.

In addition local laws dictate that the machinery, equipment and materials used in operations shall be in conformity with international standard & specifications and shall satisfy safety & efficiency requirements.

2. QUALITY ASSURANCE

2.1 Quality Assurance (QA) System

2.1.1 All activities and services associated with the scope of this Guideline shall be performed by contractors/ vendors approved by the company.

2.1.2 The contractors/ vendors shall operate Quality Management Systems (QMS) within their organizations to ensure that the requirements of this Guideline are fully achieved.

The Contractor's Quality Manual shall provide details for the preparation of a Quality Plan, which shall include provisions for the QA/QC of services activities.

2.1.3 The effectiveness of the contractors' QMS may be subject to monitoring by company or its representative and may be audited following an agreed period of notice.

2.1.4 The contractors/ vendors shall make regular QA audits on all their sub- contractors/ suppliers. Details of these audits shall be made available to the company when requested.

2.1.5 The contractor/ vendor shall maintain sufficient Inspection and QA staff, independent of the service provider management, to ensure that the QMS is correctly implemented and that all related documentation is available.

2.2 Quality Plan (QP)

2.2.1 Contracted activities shall be performed in accordance with an approved QP.

2.2.2 The level of detail required in the QP shall be commensurate with the scope of services provided.

2.2.3 The quality of works is an essential factor in carrying out all services & activities covered by this Document.

2.2.4 During services/activities, Quality Assurance/Quality Control issues are the responsibility of the contractors and shall be approved and certified by approved Third Party Agency (TPA).

2.2.5 Conflicts between contractor & TPA shall be reported in writing to the company for resolution.

2.3 Inspection and Certification Requirements

Inspection and certification requirements for material shall be certified to defined standards

3. INTEGRITY ASSURANCE PROCESS

This section defines the process which shall be complied with, to provide Integrity Assurance for pipelines in order to satisfy the purpose of PIMS as defined in section 1.3 above.

Integrity assurance is achieved through management of:

a. PEOPLE who are trained and competent;

b. EQUIPMENT that is operated as specified and maintained as fit for service/purpose through the lifecycle;

c. PROCESSES which control all integrity related actions to an appropriate standard.

This PIMS document defines how the above are managed. Pipeline integrity management is made up of a series of actions/tasks, each of which will result in a Critical Record (report, certificate, check sheet etc.) that provides evidence for integrity assurance.

3.1 Cycle of Integrity Actions

The cycle below provides a high level cycle of pipeline integrity management actions. This cycle of actions is applied iteratively throughout the lifecycle of each pipeline from concept to abandonment (decommissioning).

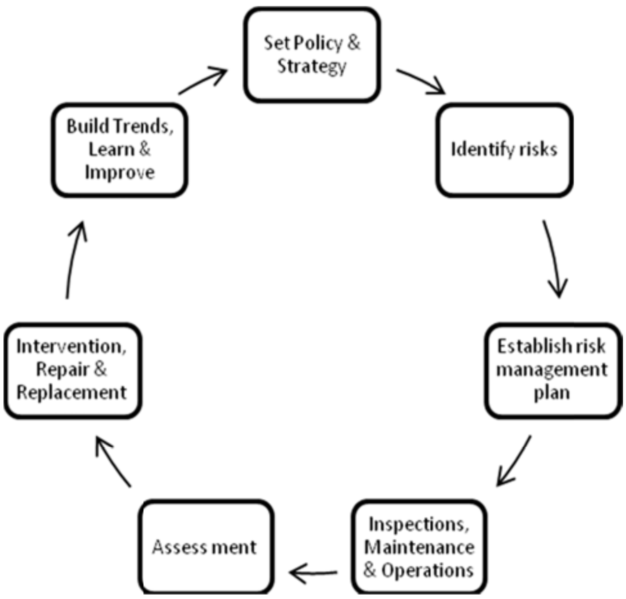

Figure-1 IM Cycle

3.2 Integrity Assurance Planning

3.2.1 A Pipeline Integrity Assurance Plan, covering all pipeline integrity actions, shall be prepared by the Integrity Authority (IA). The Integrity Assurance Plan is a process of planning actions and laying down targets against which performance will be measured. An example is given in Appendix- I.

3.2.2 The pipeline Integrity Assurance Plans shall include:

a. A list of pipeline integrity actions that will be carried out;
b. Clearly labeled name and contact details of the person responsible;
c. A list of the integrity assurance Standards, Practices and Procedures that shall be complied with;
d. A list of the integrity assurance critical records, including their location, revision and update history;
e. A list of actions to maintain integrity assurance, including who is responsible and target dates;
f. Plan date, revision; author and completion status.

3.2.3 The Integrity Assurance Plan shall be signed and maintained up-to-date through monthly revisions.

3.3 Integrity Assurance Standards and Records

The Integrity Assurance activities, standards and records requirements are listed below in specified in Appendix-A and is broken down according to the pipeline life cycle and lists the relevant PIMS section in this document under which further details of the integrity management activities may be found.

4. ROLES AND RESPONSIBILITIES

4.1 Lines of Accountability/Responsibility

Roles and responsibilities for the integrity assurance of the pipeline system shall be clearly defined and assigned throughout the asset lifecycle. Appropriate communication and training shall be in place to ensure that relevant personnel understand the responsibilities, requirements and activities assigned to them as part of PIMS

4.2 Integrity Authority (Manager Integrity)

4.2.1 Overall responsibility for integrity and Single Point Accountability (SPA) is with the Manager Integrity (MI) who acts as the Integrity Authority (IA). The IA is accountable for developing policies, strategies and procedures under an Integrity Management Framework (IMF) and for assuring compliance with the IMF by the Operating Assets and by Projects.

4.2.2 Key accountabilities of the IA include:

a. Developing and updating the PIMS assurance plan;
b. Assuring all relevant PIMS activities are carried out in accordance with the Company PIMS;
c. Assuring inspection and maintenance programmes are executed effectively;
d. Assuring all PIMS operations risks are identified and assessed, plans prepared and approved prior to implementing inspections, repairs or other

interventions;

e. Assuring that all PIMS records and documents are maintained, all personnel associated with PIMS activities are competent and trained, any proposed changes or incidents are communicated and approved in accordance with COMPANY Standards, Practices and Procedures;
f. Ensuring that critical records are maintained;
g. Acting as the focal point for all reporting relating to PIMS operations;
h. Carrying out verification and audit of PIMS operations and activities ensuring actions arising are completed and lessons learned are fed back effectively and efficiently;
i. Appointing competent personnel to support PIMS operations and activities;
i. Providing integrity support for PIMS activities in the operating assets.

4.3 <u>Responsibility for Assets (Asset Managers)</u>

4.3.1 Ownership and accountability for Integrity Management rests with the Asset Managers for all facilities under their custody. The Asset Managers are responsible for the day-day front line integrity activities at site.

4.3.2 The Asset Manager shall be the SPA for integrity matters within the Asset. The key interface between the Asset and Integrity Division shall be between the Integrity Authority and the Asset Manager.

4.3.3 The Asset Manager is responsible for:

a. Site operations related to corrosion control and monitoring;
b. Support planned surveys and inspections;
c. Monitoring and reporting excursions out-with operating limits;
d. Awareness of and compliance with PIMS;
e. Feedback of lessons learned to the Integrity Coordinator

4.4 <u>Responsibility for Projects (Project Managers)</u>

4.4.1 Ownership and accountability for integrity management rests with the Project Managers for all projects under their control. The Project Managers are responsible for the delivery of integrity of the resulting facilities upon handover to operations.

4.4.2 The Project Manager shall be the SPA for integrity matters within the Project. The key interface between the Project and Integrity Division shall be between the Integrity Authority and the Project Manager.

4.4.3 The Project Manager is responsible for:

a. Integrity during design and construction;
b. Ensuring deviations from integrity requirements are raised by the PMT and approved by the TA;
c. Handover of critical documents.

4.5 <u>Technical Authority (Subsea Pipelines Team Leader)</u>

4.5.1 A Technical Authority (TA) shall be appointed for pipelines. Further Technical Authorities may be required for specific disciplines key to pipeline integrity, such as

Corrosion and Subsea Inspections.

4.5.2 The primary role of TA(s) is to manage technical integrity assurance within their designated engineering discipline or activity by ensuring the safe and consistent application of company and regulatory codes and standards and good engineering practices.

4.5.3 The TA is the primary contact in the specified area of expertise.

4.5.4 Key responsibilities include:

a. Assuring the pipeline engineering aspects of PIMS;
b. Assuring the competency of personnel appointed to implement PIMS operations and activities;
c. Providing specialist technical input into the development of integrity performance standards, inspection, and test strategies and programmes, including suitable acceptance criteria;
d. Assessing the effect of any process or equipment changes on pipeline integrity;
e. Assure all deviations from the approved standards and processes are identified, fully justified technically, and are authorised before implementation;
f. Performing technical reviews of the pipeline system;
g. Coordinating the efforts of other TAs (as necessary) to ensure delivery of their responsibilities under PIMS
h. Making recommendations to the IA to ensure the on-going integrity of pipelines;
i. Maintaining awareness of developments in the broader pipeline engineering discipline community to ensure adoption of latest practices and sharing of lessons

4.6 <u>Inspection Authority (Inspection Services Manager)</u>

4.6.1 The Inspection Authority shall be responsible for all of the inspection activities related to company pipelines, including but not limited to Intelligent Pigging, ROV Inspections and CP Surveys.

4.6.2 The Inspection Authority is responsible for:

a. Planning of all inspections relating to pipelines including subsea, topsides and landfall;
b. Definition of performance standards for all inspections, interventions and repairs;
c. Execution of planned surveys and inspections;
d. Planning and execution of interventions and repairs;
e. Reporting;
f. Liaising with the Maintenance Manager for inspection on any the topside elements of the pipeline/riser.

4.7 <u>Subsea Maintenance & Repair Authority (Sub-sea Maintenance Manager)</u>

The Subsea Maintenance & Repair Authority shall be responsible for all interventions, maintenance & repair activities related to pipelines. Typically this involves any equipment in areas in sight/reach of the divers/marine. The Subsea Maintenance & Repair Authority is responsible for:

a. Definition of performance standards for all interventions and repairs;
b. Planning and execution of interventions and repairs including subsea, topsides and landfall;
c. Reporting;
d. Liaising with the maintenance manager for intervention and repair on any the topside elements of the pipeline/riser.

4.8 Topsides Maintenance & Repair Authority (Maintenance Manager)

The Topsides Maintenance & Repair Authority shall be responsible for all interventions, maintenance & repair activities for the topsides & jackets as recommended by the Inspection Authority

4.9 Integrity Coordinator

4.9.1 The Integrity Coordinator shall be responsible for the collection and collation of data, the assessment of the data and the optimal use of the data in the forward management of pipeline integrity within the company. The integrity coordinator ultimately reports to IA.

4.9.2 The Integrity Coordinator is responsible for:
a. Assessment of inspection and maintenance results;
b. Anomaly management; produce status reports;
c. Building trends; lessons learned;
d. Custody of records;
e. Development and calculation of integrity KPIs;
f. Annual review of PIMS and PIMS activities.

4.10 Materials and Corrosion Authority (Technical Integrity Manager)

4.10.1 Corrosion has been recognized as a major integrity threat to the pipelines. The Materials and Corrosion Authority shall focus on the management and mitigation of the corrosion threats including the assessment of corrosion damage uncovered during inspections.

4.10.2. The Materials and Corrosion Authority is responsible for:
a. Corrosion Management Strategy;
b. Performing integrity assessments;
c. Recommending interventions, repairs and replacements.

4.10.3 The Materials and Corrosion Authority shall be responsible for the interfaces and co- ordination between Integrity Division and the company projects, and this includes:
a. Specifying integrity requirements for projects;
b. Checking that projects have included requirements in the specifications;
c. Auditing of integrity requirements throughout project execution.

4.11 Management of Contractors

It is the responsibility of the PM to ensure that the contract terms and conditions shall specify, for any pipeline integrity related activity, that the Contractor must demonstrate through provision of a Quality Plan, compliance with the PIMS. Contractors work shall be verified through audit and verification as specified by QHSE division.

4.12 RACI Chart

For Responsibility/Accountability/Consulted/Informed Chart (RACI), refer to Appendix-K of this document.

5. CRITICAL RECORDS

5.1 Critical Records Requirements

5.1.1. Specific information about the design, construction, commissioning and operations of pipelines is required in order to maintain Asset Integrity. Transfer of critical data from design to operations is essential to ensure operations are kept within the intended design parameters

5.1.3 Critical records shall be retained for the lifetime of the pipeline. Responsibility for the definition of critical records rests with Integrity Division.

5.2 List of Critical Records

All the critical records for integrity assurance of pipelines are listed per activity in a Table.

5.3 Software and Databases

5.3.1. ERP

The computerized maintenance management system as official database repository for all equipment that must have its integrity assured. The company shall plan a long term strategic commitment to continue with the central ERP solution and asset database. The Asset Register and hierarchy as defined, stored and maintained in database is the master list for all life cycle stages. Any updates to the asset register shall only be made in the system.

The data base shall be used as follows:

I. Project Phase

Data shall be prepared and entered for newly constructed pipelines in accordance with following documents to be developed during the project phase:

a. Operations, Maintenance & Integrity philosophy for Projects
b. Procedure for in- house routine for Asset registration.
c. Data Sheets for computerised maintenance management system of instruments and control equipment.

II. Operations Phase

a. All maintenance, inspection, monitoring, intervention and repair activities shall be scheduled in the above data base system, whether those activities are planned or unplanned.
b. Work orders shall be raised in the system for all scheduled activities.
c. Work orders, completion certificates and other evidence of integrity assurance activities shall be recorded in the system against the appropriate asset reference number according to the system User Guide for Integrity Engineers.

5.3.2. PIMS Database

The Pipeline Integrity Management System (PIMS) is a standalone database developed and managed for storing integrity data (ID) and referencing results. PIMS shall be used by ID to store the following types of data relating to the Operations phase:

a. External inspection data and reports.
b. Intelligent pigging data and reports.
c. Monitoring data and reports.
d. ROV reports.
e. Remediation reports.
f. Corrosion monitoring results and reports.
g. Note that the Integrity Data Base Management System (IDBMS) project will define the on-going requirements for population, use and management of PIMS

6. PIPELINE SYSTEMS

6.1 Pipelines Covered

All pipelines onshore and offshore are covered by PIMS. This includes but is not limited to:

a. Transmission and export pipelines (oil, gas)
b. Flow lines.
c. Water injection lines.
d. Loading lines.
e. Subsea flare lines.

6.2 Pipelines system boundaries

All pipeline systems include the main flow path and any appurtenances.

a. At subsea installations, the pipeline ends at the point of connection to the Christmas tree or butterfly valve.
b. At platforms and wellhead towers the pipeline ends at the flange above the riser.

6.2.1. Pig Launchers / Receivers

The pipeline system includes Pig launchers & receivers.
(Note: Although included as part of the pipeline system, inspection & maintenance of pig launchers and receivers is normally considered in the Pressure Equipment Integrity Management System).

6.2.2. <u>Without Pig Launchers / Receivers</u>

The pipeline system extends to the isolation flange where a trap could be fitted. If no such flange exists, the pipeline extends to the first isolation valve or specification break off the pipeline.

6.2.3. <u>Tees</u>

The pipeline system extends to the first isolation valve or specification break beyond the tee.

6.2.4. <u>Landfall / Onshore</u>

The landfall / onshore section is part of the pipeline system.

6.2.5 <u>Flare lines</u>

The flare line ends at the flange above the riser on the flare tower.

6.3 <u>Pipelines Support Systems</u>

6.3.1. The pipeline system includes riser clamps and other support structures such as trestles, grout bags and rock berms.

6.3.2 A number of other primary systems exist that directly affect the safe operation, integrity and operability of the pipeline system. These systems must be effectively managed to ensure integrity. These include pressure protection devices such as valves; control devices ; shut down systems ; and electrical equipment . For the IM requirements of these systems then refer to the respective IMS.

6.3.3. It is the responsibility of the Asset Operator to ensure compliance with the requirements of all relevant IMS, noting the impact that any failure of one system may have on another

7. <u>COMPETENCE ASSURANCE</u>

7.1 <u>Pipelines Covered</u>

7.1.1. The design, installation, testing, operation, maintenance and abandonment of the pipeline systems shall be carried out by suitably qualified and competent persons, under the supervision of a suitably qualified and experienced engineer. All company and contractor personnel involved in PIMS activities must be appropriately trained and formally assessed as competent to perform the tasks to be undertaken

7.1.2. Through their PIMS integrity assurance plan, the IA will define, using the guidance provided by the TA, the training and competence requirements for all staff and contractors involved in the delivery of PIMS within their sphere of responsibility. The PIMS activities are defined in the section covering Integrity Assurance (see Section 3)

7.2 Applicability

Training and competency assurance shall apply to all levels within the organization including senior managers, engineers, supervisors, operations personnel and technicians both onshore and offshore.

7.3 Competence Assessment

7.3.1. Competence assessment is the responsibility of Line Managers who must ensure that their staff is equipped to carry out their responsibilities. Assessment of competency shall be periodically assessed against the specific role requirements. Line Managers shall identify on an annual basis, a list of staff whose competence is to be assured.

7.3.2 Competence should be determined through assessment and documented testing to the defined competence standards. Assessment of competence may be carried out via personnel interviews, examination of qualifications or administering tests. This process shall be managed by Manpower Development Division .

7.4 Competence Assurance

Training and competence assurance shall be approved by the TA and documented in the IDBMS

7.5 Training

7.5.1. Training requirements for individuals should follow logically from annual routine assessment of Competency. A training plan shall be developed and agreed with the Line Manager.

7.5.2. Changes approved under the formal Management of Change process may require training between annual assessments

8. INTEGRITY ASSURANCE DURING PROJECTS

a. Pipeline Integrity Management begins in the project phase and continues into operations. Decisions made during the project (e.g. the selection of materials, inhibitor and corrosion monitoring systems, pigging facilities, baseline surveys etc.) have a major influence on operational integrity throughout the lifetime of the asset. Operating experience and the lessons learned from other projects should be fed into the design. Accordingly, projects and operations personnel shall be jointly engaged in developing PIMS from the earliest stages.

b. This section addresses the actions required to ensure adequate consideration is given to operational aspects of integrity management during design and construction.

8.1 Design Process

The Project Manager (PM) is responsible for ensuring adequate design for integrity. The PM shall:

a. Ensure that adequate resources and qualified representatives are allocated during the concept, design and construction phase of new or modified pipeline facilities, to achieve adequate design for integrity;

b. Ensure that Operations, Integrity Division (ID), Technical Support Division and Discipline Engineering Division are appropriately engaged with the design process, to achieve adequate design for integrity.

The IA shall assign the technical resources necessary required to:

a. Ensure the early assessment of pipeline integrity risks including performing systematic reviews of risks as part of the project decision making process;
b. Ensure QA and control and audit processes to manage key risks and ensure pipeline integrity during procurement and construction;
c. Ensure that initial strategies and plans for inspection, monitoring, testing and repair during operations are prepared;

Key documents that shall be followed during Design, Build and Commission stages are listed in Appendix- A

8.1.1. Engagement of Integrity & Maintenance Division in Projects

The PM shall develop an engagement plan providing for input from operations at the appropriate stages of the project. This plan shall be submitted to the IA for approval. The IA shall assign the necessary resources to provide operations input to the project.

8.1.2. Impact of Projects on Existing Facilities

a. The addition of new pipelines can impact the integrity status of the existing pipeline infrastructure. PM's shall ensure that the project scope includes appropriate technical evaluations, corrosion studies and risk assessments and that integrity and maintenance are involved to the extent necessary.
b. The Remnant Life Assessment (RLA) project will be producing a set of asset replacement plans that address this requirement and specify the detailed steps that need to be followed.

8.2 Prepare for Handover from Design to Operations

8.2.1. The PM is responsible for preparing project documentation allowing the successful handover of integrity from design to operations and shall follow the guidance provided in the DNV standards & recommended practices

8.2.2. The Project shall develop and deliver:

a. Key documents and procedures required to operate the pipeline. These documents should be clear, concise and reflect key risks and management processes to ensure that pipeline integrity is not compromised during design life.
b. Documents must clearly convey the design and construction intent to operation personnel on handover. These shall include:

1. Safe operating limits (pressure, temperature, fluids, flows etc.);
2. Operating temperature;
3. Performance standards (if applicable);
4. Spares philosophy;
5. Contingency plans;
6. Clear communication of key integrity risks and design aspects relevant to operational personnel;
7. Transfer of risk assessment to operations;
8. Risks that have been mitigated;
9. Transfer of hazards to the risk register;
10. Procedures to verify that the pipeline is fit for continued operation;
11. If new design concepts or materials have been used, the project should develop requirements to verify that the design is performing as planned, together with any intervention works that may be required

9. INTEGRITY DURING OPERATIONS

The Operating Assets have a critical role to play in PIMS. As the operator, they are responsible for ensuring that the pipeline does not exceed its operating envelope and design intent; and that the required maintenance, inspections, surveillance activities and other controls are in place. The day-to day activities that are relevant to successful PIMS include:

a. Identifying and mitigating where practicable all risks associated with operations;
b. Monitoring and control of process parameters;
c. Continual liaison with and tracking activities with shore based staff;
d. Monitoring and analysis of process fluids;
e. Monitoring and maintenance of all communication and emergency shutdown systems;
f. Ensuring personnel competency;
g. Ensuring all personnel have clear instructions backed up by procedures and check lists;
h. Ensuring all planned inspection schedules by third parties or otherwise are well known;
i. Ensuring all planned maintenance routines are clearly understood and implemented and the results / actions recorded;
j. Are aware of and compliant with PIMS;

k. Feeding back of lessons learned

9.1 Commissioning

9.1.1 Operations commence with the initial filling of the pipeline with the fluid to be transported. Procedures for commissioning shall include any detailed requirements for inspection, monitoring and testing during and immediately following commissioning. Commissioning procedures developed during Design shall be followed. Activities during commissioning shall be in compliance with the company guidelines for commissioning.

9.1.2 It shall be verified that the operational limits are within the design conditions and that appropriate verification has been undertaken. Particular attention should be given to:

a. Flow parameters (pressure, temperature, dew point conditions, hydrate formation sensitivity, sand production).
b. CP system.
c. Expansion, movement, lateral snaking, free spans and exposures

9.1.3 Events that occur during commissioning may lead to additional inspection and/or revised inspection plans.

9.2 Handover from Design to Operations

9.2.1 . Requirements for integrity and maintenance throughout pipeline operations shall be identified and established at the design stage. A strategy for inspection, monitoring and testing shall be established prior to commissioning as a part of the Project Risk Assessment and HSE Identification/Performance Standard processes.

9.2.2 Appropriate steps shall be taken to transfer responsibility for integrity from projects to operations. These steps are described in Subsection 8.2 of this document.

9.3 Operational Controls & Procedures

Pipelines and flow lines shall be operated in accordance with the relevant pipeline- specific operations manuals and/or procedures.

9.3.1 Pressure Monitoring & Control

a. Monitoring and control measures shall be in place to ensure that critical operating parameters are kept within the specified operating envelope.

b. Pressure monitoring and control requirements developed during design and handed over to Operations shall be followed.

c. The need to change or adjust the pressure monitoring and control requirements and incorporating changes to operating procedures may be identified by periodic risk assessments. Such changes shall be subject to the MOC process.

9.2.1 Maintenance & Inspection

All pipeline safety systems shall be periodically maintained, tested and inspected to ensure continued compliance with the Maintenance Management Strategy and relevant performance standards. As a minimum, the scope of maintenance activities shall include the following items:

a. Pressure control and over-pressure protection devices;
b. Emergency shutdown systems and automatic shutdown valves;
c. Pig traps;
d. Maintenance and inspection plans developed during design and handed over to Operations shall be followed. The frequencies for maintenance and inspection recommended in handover documents shall be adopted;
e. The need to change or adjust the maintenance and inspection requirements and incorporating changes to operating procedures may be identified by periodic risk Assessments. Such changes shall be subject to the MOC process.

9.4 Corrosion Control and Monitoring

9.4.1 The requirements for corrosion control and monitoring shall be developed from the Pipeline Risk Assessment which will identify the basis for detailed planning of all pipeline inspection and monitoring activities. Procedures for corrosion control and monitoring shall conform to the requirements of the Corrosion Management Strategy.

9.4.2 Monitoring plans shall be documented for each pipeline in the relevant operating manual or pipeline-specific corrosion control and monitoring manuals. As a minimum, these plans shall address the following:

a. Monitoring of chemical injection;
b. Corrosion coupon and probe monitoring;
c. Sampling of fluids;
d. CP system and external coating condition monitoring.

9.4.3 Periodic surveys and inspections for external corrosion are covered in Section 11 of this document.

Refer Appendix D, E & F for ‘Corrosion threats’, Corrosion monitoring techniques’ and ‘Process monitoring and internal corrosion control’ sections extracted from DNV Recommended practice DNV-RP-F116.

9.5 Interfaces

The interface between Operations and Projects is defined by an Integrated Operations Readiness Guidelines document.

10. PIPELINE RISK ASSESSMENTS

a. This section outlines the process for pipeline risk assessments that are applicable to all pipelines. The process covers risk assessments during design and operations and applies to all personnel and projects concerned with PIMS.

b. The IA shall be responsible for ensuring that all pipeline risk assessments are conducted in accordance with the relevant procedure according to the life cycle stage.

Appendix B lists the Pipeline system threats and Appendix G provides the Pipeline threats & Integrity activities matrix.

10.1 General Requirements

10.1.1 A risk-based approach shall be used to assess the status of the pipelines at each stage in the lifecycle in order to prioritize integrity management activities and plans based on the findings.

10.1.2 Risk assessment shall address threats and consequences in line with the Company business risk matrix criteria.

10.1.3 All threats that could directly or indirectly impact the integrity of the pipeline system shall be evaluated and be recorded on a pipelines risk register by the Technical Authority. To ensure continuity, risk assessment results are to be carried forward from each phase of the pipeline life cycle to the next phase:

Design => Install => Operate => Decommission => Mothball => Abandon.

10.2 Risk Assessment – Design

10.2.1 All new or modified pipeline facilities shall be subjected to risk assessment during design. Design shall also take into account the provisions of the IA in Projects guideline.

10.2.2 Early assessment and management of pipeline integrity risks, including systematic risk reviews, forms part of the project decision-making process. Results of the risk assessments carried out during design shall be incorporated into the handover documentation to operations.

10.2.3 Initial inspection and monitoring plans shall be prepared and made available prior to pipeline commissioning. The baseline inspection plan shall ensure that all new pipeline systems are subjected to external and internal inspections to establish a condition baseline no later than (6 months) after commissioning.

10.3 Pipeline Passport

Each pipeline shall have a “Pipeline PASSPORT” which summarizes the latest status of the specific pipeline. The PASSPORT shall contain the pipeline identity, the risk Assessment (based on technical and business risk), an assessment of the remaining life and recommendations for future actions. Pipeline PASSPORT is suitable for both pigged and un-pigged pipelines. Brief guidelines on the use of Pipeline PASSPORT have been developed. Examples of Pipeline PASSPORT are given in Appendix-C.

10.4 Risk Assessment – Operations

10.4.1 A complete risk assessment and updating of integrity management plans for pipeline system shall be conducted annually by the IA.

a. Identify relevant integrity threats.
b. Determine effective and appropriate risk mitigation actions including changes to operating procedures.
c. Prioritise pipelines for inspection and monitoring activities and replacement projects.
d. Schedule inspection, monitoring and risk mitigation actions.
e. Assess/demonstrate the benefits derived from mitigation actions.

10.4.2 The integrity threats to be considered are contained in Appendix-G.

10.4.3 Risk assessment shall also be conducted in accordance with the provisions of Pipeline PASSPORT and take into account business as well as technical risks prior to and post mitigation actions. Its purpose shall be to:

a. Establish the current level of risk associated with the presence of corrosion anomalies.
b. Determine effective and appropriate risk mitigation actions.
c. Prioritise pipelines for inspection and monitoring activities and replacement projects.
d. Schedule inspection, monitoring and risk mitigation actions.
e. Assess/demonstrate the benefits derived from mitigation actions.
f. Documents and results of risk assessments carried out during operations shall be stored in data base system by the IA.

10.5 Remnant Life Assessment

The RLA process is a specific type of risk assessment, addressing the economic management of condition degradation. Its purpose is to ascertain whether the pipeline has sufficient remaining life to meet company's business requirements and the outputs feed one or more of the KPIs used to measure business performance. If replacement or monitoring is necessary, the RLA process will provide the timescale and priority. Currently, pipeline deterministic remnant life is calculated as part of the Pipeline PASSPORT process.

11. INSPECTION & MONITORING

a. This section details the periodic inspection and monitoring process that is applicable to all pipelines including contracted work. Note that routine operational inspections and monitoring performed by the operating assets are covered in Section 9.

b. The objective of inspections is to establish pipeline condition through periodic surveys and / or physical inspections. The objective of monitoring activities is to collect data and evaluate results from relevant processes and parameters that can be used to measure or infer pipeline condition and assess risks.

c. The results of the inspection and monitoring process shall be used as the basis for anomaly assessments; remediation activities; replacement programmes; to inform risk assessments; and for the evaluation of prevention and mitigation strategies that reduce the impact of specific integrity threats.

11.1 Inspection and Monitoring Responsibilities

a. Responsibility for implementing the inspection and monitoring process shall be shared between the asset operators and Integrity Division. Accountability for ensuring the effective implementation of the inspection and monitoring process shall lie with Integrity Division/ Integrity Authority.

b. It is a requirement that the inspection and monitoring strategies and procedures are aligned to the requirements of the applicable HSE Performance Standard and Written Schemes of Examination and consistent with the provisions of the Corrosion Management Strategy.

11.2 Inspection and Monitoring Planning

a. Inspection and monitoring of pipelines is the responsibility of the Inspection Authority to ensure all inspection and monitoring activities are adequately planned, executed, evaluated and reported.

b. An annual inspection and monitoring plan shall be developed from the annual Pipeline Risk Assessment and take into consideration documents prepared in Design and handed over to Operations.

c. Inspections and monitoring shall be carried out as scheduled events, in accordance with the risk assessment outputs and taking into account the operational integrity requirements from the design phase. Additional inspection and monitoring requirements shall be taken into account for any pipeline that is also subject to a Written Scheme of Examination as a result of it being safety critical and falling within the scope of HSE.

11.2.1 Inspection Frequency

Company has committed to a programme of Intelligent Pigging (IP) inspections for its rigid subsea pipelines. The decision to conduct an IP is made according to business criticality using the risk-based process that is documented in Pipeline PASSPORT. There is currently no mandatory inspection frequency for IP.

The IP inspection of pipelines shall be undertaken in accordance with relevant DNV standards/ RP. Frequencies for all other types of inspection and survey such as remotely operated vehicle surveys and diver inspections shall also follow relevant DNV standards/ RP.

11.2.2 Inspection Methods

The inspection method shall be selected to ensure:

a. Adequate anomaly detection capability, sizing accuracy and reliability;
b. Compatibility with the pipeline and its operation.

Acceptable inspection methods include (but are not limited to):

a. Intelligent Pigging (IP) using magnetic flux or ultrasonic sensing techniques; the full pipeline length shall be inspected, including the riser and onshore sections up to pig traps.
b. IP is mandatory for metal loss anomaly detection in all new pipelines and is the preferred method for detecting metal loss anomalies in all pipelines. When pig launchers / receivers are not already fitted, the installation of permanent or temporary facilities shall be considered.
c. IP programmes shall follow the guidelines provided by the Pipeline Operators Forum.
d. Non-destructive testing (NDT) using ultrasonic wall thickness measurement.
e. External visual and acoustic surveillance using ROV"s for detecting free spans, buckles, external impact damage and coating condition;
f. Visual inspections.

11.2.3 Inspection Planning

Detailed inspection plans shall be prepared and documented for each pipeline in advance of all inspections. Scheduling shall be closely coordinated with operations to minimize the impact of inspection activities. Plans should include:

a. A general description of the pipeline(s) to be inspected and method to be used;
b. A summary of the scope of work;
c. Required procedures, work instructions, responsibilities and lines of communication with Company and Contractors;
d. A specification of reporting requirements;
e. Risk management plans for inspection activities addressing any safety, health and environment risks and the potential impact of the project on pipeline operations;
f. A detailed execution schedule;
g. Provision for making revisions to plans to incorporate on-going results from the inspection activities.

11.2.4 Inspection Deferrals

Deferrals shall require a specific inspection interval extension approval by the IA in accordance with the relevant procedures and shall be supported by a risk assessment of the proposed delay.

11.2.5 Monitoring Methods

Acceptable monitoring methods include but are not necessarily limited to:

a. Corrosion monitoring using weight loss coupons, probes etc.
b. Monitoring of product and chemical inhibition including operational pigging;
c. Close proximity surveys/ Close Interval Potential Survey;
d. ROV surveys for monitoring the cathodic protection potential;
e. Monitoring of pipeline routes for any activities that could cause mechanical damage (e.g. vessel activity, fishing, trawling, construction projects);
f. Shore approach monitoring;
g. Leak detection.

Monitoring may be carried out as scheduled events or continuous activities, the requirements of which shall be determined from risk assessments.

11.2.6 Monitoring Planning

Corrosion monitoring plans shall be documented for each pipeline in accordance with the relevant DNV standard/ RP. As a minimum, these plans should address the following:

a. Corrosion coupon and probe monitoring;
b. Monitoring of chemical injection availability, hardware and operational pigging activities;
c. Fluid sampling;
d. Cathodic protection system and condition monitoring of external coating including concrete weight coating.

External survey plans shall be planned and documented as per Clause 11.2.3 for Inspection Planning. These should address as a minimum the following:

a. Evidence of leakage;
b. Evaluation of the location, depth and length of any buried and exposed section of pipeline;
c. Condition of the pipeline and attachments /appurtenances / other components and crossings;
d. Stability of the pipeline, including location, length and height of any unsupported spans and crossovers; upheaval buckling or snaking;
e. Condition of pipeline supports - ensuring that rock-dumps are intact and that the pipeline remains positioned within the intended support area;
f. Evidence of any damage to the pipeline (including signs of dropped objects, equipment handling errors, anchor impacts, dragging, fishing);
g. Debris and seabed features in close proximity to the pipeline.

Requirements for other monitoring activities shall be evaluated on a case-by-case basis and dependent on the results of risk assessments.

11.3 Evaluation of Inspection and Monitoring Results

11.3.1 The outputs from inspection and monitoring shall be reviewed by the Inspection Authority and used to determine if actions are necessary to repair or remediate any discovered condition. In other situations the appropriate response is to modify preventive and mitigation measures to control the integrity threat(s) causing the defect or anomaly discovered during inspection or monitoring. The outputs from inspection and monitoring shall be used to schedule future activities and as an input to risk-based integrity planning.

a. An evaluation of the results shall be performed to determine if the inspection or monitoring has been done according to plan including quality requirements. If not, the process shall be repeated.
b. For inspections, a preliminary evaluation shall be made with respect to the impact on immediate pipeline integrity. Recommendations shall be made for further investigations or additional assessment of the findings of the inspection, including the need for any additional inspections, examinations or monitoring.
c. For monitoring, an evaluation shall be made to ensure that monitoring data are within the specified limits. The need for any additional inspections, examinations or monitoring activities shall be determined taking into account the possible impact on pipeline integrity

11.4 Recording of Inspection and Monitoring Results

All inspection and monitoring activities performed on pipelines, routine or non-routine, shall be initiated, planned and tracked in data base systems using Master preventive maintenance system according to the guidelines in the maintenance manuals. Recording of certificates, reports and results from inspections and monitoring activities shall be subject to the requirements of the IDBMS and the required information uploaded in accordance with the requirements of the IDBMS. The tracking and completion of inspection and monitoring activities shall be recorded in the data base systems against the correct equipment tag/asset number in the Equipment module.

12. INTEGRITY ASSESSMENT

12.1 Assessing Deviations

a. Deviations may involve technical, process or personnel-related aspects of PIMS.

b. A technical deviation is any anomaly, defect, degradation mechanism or other non-conformance to do with the physical asset that has the potential to cause failure or a serious incident.

c. A process deviation is one that requires a change to a PIMS plan, programme or activity or process.

d. Changes in key staff, re-organizations, or external resources that may impact the satisfactory delivery of PIMS, is covered by a personnel deviation.

12.2 Technical Deviations

This category of deviation includes anomalies found during inspection and monitoring; lack of records or data; and may include any other type of non-compliance that could affect the physical integrity of the pipeline.

12.2.1 Anomaly Management

An anomaly is any condition that may impair the pipelines fitness for purpose when measured against the design intent of the pipeline. Anomalies may be discovered during inspection, monitoring, or as a result of routine operations and maintenance activities.

The objective of the anomaly management process is to perform a thorough evaluation of all such anomalies and their possible impact on continuing operation of the pipeline, in order to determine the appropriate response.

The anomaly management process applies to any discovered pipeline condition that could significantly impact integrity of the pipeline or the pipeline system. This may include, for example:

a. Corrosion;
b. Deficiencies in corrosion protection systems;
c. Dents;
d. Gouges;
e. Cracks;
f. Unsupported pipe (e.g. free spans);
g. Lateral displacements;
h. Buckles.

The level at which anomalies are to be recorded and reported is covered by the relevant Company specifications for inspection and monitoring and in the requirements specifications for the relevant survey or monitoring activity.

The decision regarding the most appropriate action shall be taken by the Integrity Authority in consultation with the Technical Authority. The following items shall however be considered, as a minimum, when developing detailed plans for personnel and Contractors involved in inspection, monitoring and surveys:

a. Roles and responsibilities;
b. Administration and tracking of anomalies;
c. Assessing the severity and fitness for purpose;
d. Determining the appropriate response to an anomaly;
e. Resolution and closure;
f. Reporting.

12.2.2 Fitness for Purpose Assessment

Corrosion represents a specific threat that is well recognized within the Company as requiring particular attention. The process described below addresses metal loss corrosion anomalies only. Other technical methods of assessment are required for each class of anomaly: these methods are not covered here. In all cases, the preferred method of technical assessment is to use the guidelines provided by the Pipeline Defect Assessment Manual (PDAM).

Corrosion Defect Assessment

A fitness-for-purpose assessment shall be performed on all potentially unacceptable anomalies using accepted industry standards and recommended practices by a suitably qualified and competent person appointed by the IA. Different levels of defect assessment ranging from „screening" methods to very sophisticated Finite Element Analysis (FEA) methods are available. Accepted methods include but should not be limited to:

a. ASME B31.G;
b. Modified B31.G (R-STRENGTH);
c. DNV-OS-F101
d. PDAM.

Assessments shall include an evaluation of:

a. The immediate fitness of the pipeline for continued operation. Accuracy and uncertainties of anomaly data shall be considered in this evaluation;
b. Estimated future degradation rates (e.g. corrosion growth rates) and estimated impact on future pipeline fitness for purpose;
c. The timing of any future repairs or interventions that may be required;
d. The timing of any future inspections;
e. Potential root cause(s) and preventive measures.

Some anomalies may require a detailed engineering assessment by discipline engineers or specialist Contractors/ Consultants during the assessment and recommendations process using higher level assessment.

12.2.3 Integrity Status Reports

In order to easily manage the risks associated with any pipeline, the integrity authority shall produce an integrity status report for each pipeline covering all key assessment findings including anomalies, excursions, deviations, fitness-for-purpose, modifications, repairs, mitigations etc.

12.3 Missing Records

It is not uncommon for historical records about the pipeline design, construction or results of inspections, to be either absent or difficult to recover. In such situations, the procedure, risk assessment, evaluation or analysis shall make conservative assumptions and will be approved by the TA. If application of conservative assumptions leads to unacceptable findings or results, then steps shall be taken to either recover the missing records or to take new physical measurements to reduce the uncertainty.

12.4 Process Deviations

Alteration of, non-compliance with, or absence of any process, methodology, model or other significant change shall be submitted to the Management of Change procedure.

12.5 Personnel Deviations

Any item involving staffing or resources that may impact the satisfactory delivery of PIMS should be considered a deviation. Examples include:

a. Changes in key personnel;
b. Re-organizations;
c. Lack of competence.

Such deviations require approval according to the Management of Change procedure.

13. INTERVENTION & REPAIR

This section details the intervention and repair process that is applicable to all Company pipelines including contracted work.

a. The anomaly management process will normally generate the majority of requirements for pipeline interventions and/or repairs. Conditions may require immediate or scheduled interventions or repairs. The remediation of these conditions is addressed by this section of PIMS.

b. Unplanned events including third party damage incidents shall invoke the Company emergency pipeline repair process. Refer to Section 17 for Emergency Response.

c. The objective of the intervention and repair process is to address potentially dangerous conditions by restoring the pipeline to (or as close as is reasonably practicable) the original design condition using the most cost effective intervention or repair method.

13.1 Intervention and Repair Responsibilities

Responsibility for implementing the intervention and repair process is the Subsea Maintenance & Repair Authority/Inspection Authority (Inspection Services Manager).

13.2 Health, Safety & Environment Regulations

Interventions and repairs involve direct physical contact with the pipe or its immediate surroundings. Some repairs will involve breaking pressure containment of the pipeline system. HSE requirements shall be fully taken into account when planning and executing pipeline interventions and repairs.

The TA/IA/ Project Manager shall ensure that Company regulations are complied with and the relevant records required for integrity assurance are generated, approved and managed. Of particular relevance are the following Company HSE requirements:

- Mechanical Isolations
- Breaking Containment
- Marine Operations
- Pressure / Leak Testing

13.3 Intervention and Repair Planning

Detailed plans shall be prepared and documented in advance of all interventions or repairs. Scheduling shall be closely coordinated with operations to minimize the impact of intervention or repair activities. Plans shall consider and include where appropriate:

a. Determining the most appropriate method (see Subsection 13.6);
b. Mobilization of equipment and personnel;
c. Pipeline preparation, including any necessary adjustments to operating conditions including de-commissioning;
d. Implementing the repair or intervention;
e. Inspection and testing;
f. Returning pipeline to normal operations including re-commissioning;
g. Documentation and records.

13.4 Intervention

Pipeline intervention activities are mainly corrective actions related to the external pipeline seabed interaction and support conditions. These activities are appropriate for conditions such as:

a. Unsupported spans
b. Lateral or upheaval buckling;
c. Lateral displacements;
d. Sediment build-up/ burial preventing or impeding necessary lateral movement;
e. On bottom stability (e.g. rectification of concrete weight coating damage);
f. Corrosion protection system deficiencies such as depleted anodes or coating damage.

13.5 Repair

13.5.1 Pipeline repairs are corrective actions performed with the objective of restoring compliance with requirements related to functionality, structural integrity and / or pressure containment of the pipeline system. Repairs address unacceptable defects such as:

a. Metal loss;
b. Cracks;
c. Mechanical damage;
d. Loss of containment due to any cause.

13.5.2 In some circumstances a temporary repair may be acceptable until a permanent repair can be implemented. In such cases it must be clearly documented and communicated that the pipelines integrity and safety level is being maintained either by the temporary repair itself and/or in combination with other precautions such as reduced pressure or flow rate. The maximum period shall be specified before a permanent repair solution must be implemented. A temporary repair shall be approved by the TA.

13.6 Determination of Method

13.6.1 The selected method shall be determined after a formal evaluation of the anomalous condition and suitable repair or intervention methods by suitably qualified and experienced specialists.

13.6.2 Responsibility for recommending the most suitable intervention or repair method lies with Integrity Division.

13.7 Spare Parts

13.7.1 In the event that intervention or repair is required, the availability of spares may be a key factor in determining the most appropriate method.

13.7.2 The IA is responsible for ensuring that their pipelines have adequate spares according to the Spare Parts Management philosophy of the Company

13.7.3 For contracted equipment, the IA is responsible for ensuring that as part of the contract it is agreed that a minimum level of equipment availability will be assured via the Contractors own maintenance and spares management systems.

13.7.4 Dependent on the equipment criticality, the spares available for performing maintenance (preventative, corrective, breakdown, shutdown or service) shall be assessed by the appropriate spares technical custodian. Ensuring assessments have been done is the responsibility of the IA.

13.7.5 Spares assessments shall be stored as a critical record and shall form part of the IA Integrity Assurance Plan.

14. PREVENTION AND MITIGATION

This section details the prevention and mitigation process that is applicable to all pipelines including contracted work.

Preventive measures and mitigating activities are taken to reduce the likelihood or the consequence of failure and are typically operational in their nature, which can be seen from the following examples:

a. Optimising corrosion inhibition practices to reduce the impact of internal corrosion;
b. Regular operational maintenance pigging to remove scale and liquids to mitigate internal corrosion;
c. Routine patrols or monitoring of shipping activity in pipeline corridors to mitigate third party damage.

14.1 Prevention and Mitigation Responsibilities

Responsibility for planning and reviewing the prevention and mitigation process rests with Integrity Division. Day-to-day responsibility for implementation rests with the operating assets. Accountability for ensuring the effective implementation of prevention and mitigation process lies with Integrity Division.

14.2 Prevention and Mitigation Planning

14.2.1 Prevention and mitigation measures are built into the operating manuals and written schemes of examination developed during the design phase and handed over to operations prior to pipeline commissioning. The starting point for prevention and mitigation planning is therefore the handover documentation.

14.2.2 For new pipelines, the handover prevention and mitigation plan shall be followed.

14.2.3 For existing pipelines, Integrity Division shall conduct an (annual) review of the measures in place.

14.2.4 The review shall consider:

a. Failure or incident data and investigations (across the operating assets);
b. Repairs or replacements;
c. Results and reports on corrosion monitoring activities;
d. Results and report of subsea inspections and surveys;
e. Any other discovered conditions that may need further engineering and/or operational controls to improve the safety or integrity of the pipeline;
f. Marine operations reports;
g. Risk assessments (conducted during Design or Operations).

14.2.5 If changes or adjustments to the existing prevention and mitigation measures are recommended as a result of the review, these should be considered and approved via the MOC process.

15. MOTHBALLING AND ABANDONMENT

15.1 Mothballing

Mothballing is used for the safe keeping of a pipeline to sustain its integrity and condition for a defined period of time, prior to re-entry into service. The provisions of relevant DNV standard/ RP shall be adhered to.

15.2 Abandonment

15.2.1 After commissioning of a replaced pipeline, the old pipeline shall be decommissioned and adequately cleaned (by pigging wherever possible or using high velocity water flushing) to ensure that there is no environmental threat due to pollution.

15.2.2 The pipeline will then be physically disconnected from existing operational facilities and abandoned without the need for further inspection or maintenance.

15.2.3 Removal of pipeline sections will be considered at complexes and well head towers in order to reduce the loading on other operating facilities (e.g. risers, crossovers), to avoid sea bed congestion around existing / future platforms and to allow laying of new pipelines without crossovers, in line with the agreed strategy

16. MANAGEMENT OF CHANGE

16.1 General

16.1.1 Changes during the pipeline design, fabrication, installation, construction or operation (including maintenance, inspection and monitoring, repair and rehabilitation and other PIMS activities) can lead to a requirement to change, modify or adjust an existing facility or process. This includes processes in the PIMS itself.

16.1.2 Physical modifications to pipelines, pipeline facilities, changes to operating conditions, or changes to procedures that go beyond the design operating limits or operating manual limits, must be managed in a structured manner to identify and manage potential impacts on the integrity of the system. It is essential that proper documentation of changes and communication is prepared and communicated to those who need to be informed.

16.2 Management of Change Procedure

16.2.1 In the case of plant modifications up to US$50,000 in value, the MOC shall be in accordance with Company Procedure Management of Engineering Changes: Plant Modification and Hazardous Areas Classifications.

16.2.2 For Projects, the guidelines provided in Management of Change for Projects shall be followed.

16.2.3 All other changes that may impact the risk to pipeline integrity and which are not covered by either of the above shall be managed in accordance with this procedure.

16.2.4 Examples of the type of events that would trigger MOC:

a. Deviation from procedures;

b. Modifications to the pipeline system or associated components or structures (see Section 6);
c. Changes to operating conditions compared to the basis of design.

16.2.5 The MOC shall address the following key points:

a. Assessment of any implications of the change including risks;
b. Mitigation action to reduce/eliminate the risk;
c. Roles and responsibilities;
d. Review and formal approval;
e. Communication;
f. Tracking and close-out of any required actions;
g. Documentation and recording.

16.3 MOC Process for Engineering Changes/Plant Modifications

16.3.1 Plant Modifications

For any equipment categorized under PIMS, COMPANY and Contractors shall follow Management of Engineering Change, Plant Modifications and Hazardous Area Classification to ensure that any proposed change, either temporary or permanent does not introduce any unnecessary hazards/risks. The hazards of equipment is controlled through the asset risk register, in addition to ensuring that all documentation associated with new/modified plant is recorded, stored and updated within the relevant asset data sources. This overall process shall ensure that any new/modified asset meets the original specification and deviations to the design have not compromised integrity.

16.3.2 New Equipment/Refurbishment

All projects, new builds and refurbishment programs (Green field) for pipelines will comply with the processes and procedures set out in major projects.

16.3.3 Maintenance

Any changes to maintenance programs must comply with the requirements of the Company maintenance strategy.

16.3.4 Abandonment/Decommissioning/Redundancy

The IA shall monitor and review KPIs in-conjunction with the current lifecycle of the equipment system, these will be reviewed against Company Asset Redundancy criteria to ascertain whether it requires implementation or the asset can be classified as redundant.

16.4 MOC for Procedures

16.4.1 All procedures shall be treated as live documents, taking guidance from approved codes of practice, company policies, procedures and international standards.

16.4.2 Approval shall be gained using the process in PIMS depending on the level of and scope of update.

16.5 MOC Register

The IA shall keep a master register of MOC applications and records. The IA is responsible for ensuring they are closed out within the timeframe specified

16.6 MOC Process for Personnel

Changes in organization or in key personnel involved in the delivery of PIMS should be recorded in the MOC register by the IA. A risk assessment shall be performed to ensure all actions are taken to minimize operational disruptions during handovers and in the future.

16.7 MOC Process for Documentation

16.7.1 This document outlines the processes involved with the establishment and development, review, approval, implementation, revision and withdrawal of documentation.

16.7.2 For the revision and updating of equipment datasheets, PMs, schematics and any other changes to plant equipment that need to be documented, relevant Company procedures should be followed.

16.8 MOC Process for Data base system software functionality

All changes required to Database system software functionality shall be processed using change Request Form and sent to the ERP Custodian Team, Corporate Performance Division.

16.9 Activities Not Requiring MOC

The following activities are considered exempt from MOC procedures:

a. Standard Maintenance: activities such as replacement of parts with spares that match the current capacity, performance or rating as the current parts;
b. Operations: Variations in operating parameters which are within the original design specifications/limits as described in Standard Operating Procedures (SOPs);
c. Inspections & Maintenance: Changes to schedules and scopes that are within written risk based policies;
d. Organizational: Reassignment of qualified personnel or routine crew changes.

17. EMERGENCY RESPONSE

17.1 Emergency Response Requirements

17.1.1 Company's requirements for Emergency Response are set out in its HSE Management Manual of Codes of Practice, Risk Assessment and Control of Major Accident Hazards; Code of practice on Crisis and Emergency

Management As they relate to PIMS, these requirements apply only to those pipelines carrying liquid hydrocarbons.

17.1.2 Emergency Procedures for Company Assets are covered by respective HSE documents.

17.2 Responsibilities

Assets are responsible for ensuring the necessary arrangements are in place to deal with all pipelines under their jurisdiction.

17.3 Emergency Repairs

17.3.1 Emergencies involving pipelines will typically require repair.

17.3.2 An Emergency Pipeline Repair Scheme (EPRS) is in place for major pipelines such as those for transmission and export lines, as well as other lines that are selected by the Assets according to criticality..

17.3.3 Company shall maintain an in-house capability to repair lines that are not covered by the EPRS. These are mainly in-field lines; stocks are held and contracts are in place for clamps and repairs for all lines outside EPRS.

17.4 Procedure

The appropriate response to an emergency shall be determined by the responsible Asset, in accordance with the relevant emergency response procedure.

18. INCIDENT INVESTIGATION

18.1 Purpose

18.1.1 The primary purpose of investigating incidents is to determine what changes are needed to improve the effectiveness of the pipeline integrity management system.

18.1.2 In PIMS, an incident is most likely to be an event that causes the loss of product through the unplanned release of service fluid due to failure of a pipe or component. For serious incidents it shall be noted that time is of the essence in order to capture the relevant information. The purpose of the investigation is to determine the cause of the incident and identify and recommend actions to prevent its recurrence. The incidents to be investigated include but are not limited to:

a. Major incidents and high potential incidents;
b. Uncontrolled releases;
c. Unexpected failures of material or equipment;
d. Accelerated rates of deterioration;
e. Excursions outside the safe operating limits.

18.2 Incident Reporting Requirements

18.2.1 Company's HSE Management System Guidelines, require procedures to be in place for the reporting and investigation of hazardous situations, near misses and incidents. Incidents must be investigated in a timely manner, with accountabilities assigned, and progress on recommended actions shall be monitored until close-out.

18.2.2 Company HSE Management requirements for incident reporting are defined in HSE regulations.

18.2.3 Loss of product due to handling operations, such as loading / offloading or breaking containment for operations such as pigging, shall be subject to the incident procedures set out in the Operating Manual for the relevant Asset.

18.3 Process

18.3.1 All significant integrity management incidents shall be investigated and reported. For serious incidents, or those incidents which could have an affect across Company operations and assets, an investigation team shall be formed and shall employ a recognized Root Cause Analysis process to ensure a thorough and comprehensive investigation is conducted. A formal investigation shall commence immediately for serious incidents. The investigation shall determine the cause of the incident and identify and recommend actions to prevent recurrence of the incident.

18.3.2 The Asset Manager or Project Manager shall ensure that the findings of the investigation are promptly addressed and resolved. They will also ensure that the lessons to be learned from the incident are documented and circulated to all other projects, assets and operations.

18.4 Incident Investigation Recording

Company Plant Failure Reports (PFRs) are used to record and monitor such incident investigations. It is the responsibility of the Site Integrity Engineer to prepare progress and close-out the PFR. Incident reports, root cause analysis findings and other documentation shall be recorded in *PIMS* and attached to the PFR.

19. KPI's & BUILDING TRENDS

19.1 Purpose

19.1.1 The purpose of performance monitoring, trend building and learning lessons is to evaluate results and to implement process improvements or corrective actions where required.

19.1.2 The collection and reporting of PIMS Key Performance Indicators (KPI''s) meets corporate requirements and will help to measure the effectiveness of the PIMS program.

19.1.3 Building trends requires the periodic assessment and review of relevant results and outcomes from PIMS activities.

19.1.4 Improvements in the integrity process come about through learning lessons from previous experience and subsequently implementing changes to the program.

19.1.5 This section sets out the process that shall be adopted for KPI"s, building trends and lessons learned.

19.2 KPI Requirements

19.2.1 Company guidelines for KPI's shall be described and the requirements set out in the Integrity Management Interim Guideline for KPI Reporting. Its requirements shall be followed.

19.2.2 The above shall cover integrity KPI's and reporting for:

a. Integrity compliance;
b. Critical safety systems.

19.2.3 Items under preparation and to be included in future revisions of the above shall include:

a. Remnant Life Assessment criteria

Note that the KPI targets are to be updated annually.

Appendix-K sets out accountabilities and responsibilities as RACI chart.

19.3 Building Trends

19.3.1 Trends shall be built from:

a. Quarterly and annual review of KPI's.
b. Capturing additional PIMS results and indicators.

19.3.2 The types of measures that are relevant for trend-building purposes include a number of operational parameters that can be captured from:

a. Process parameter reports (operations within / beyond specified limits /excursions);
b. Changes in operations, conditions, configuration or loading;
c. Damage assessment reports (IP results, fitness for service, RLA);
d. Surveillance findings (activities in proximity to pipeline that could lead to impacts);
e. Results from critical valve and control system tests;
f. Instrumentation tests.

19.4 Recommendation

Sharing of information and data within the Company need to be well developed in a structured and consistent manner. Attention need to be devoted to this important area in the Integrity Management cycle. In Section 4, the position of Integrity Coordinator has been identified and assigned the role of developing the KPIs, Building Trends and circulating Lessons Learned and it is recommended that this position be assigned to a Senior Pipeline Engineer within Integrity Division. The information assessed through trending analysis shall be reported to the Integrity Authority on a regular (monthly) basis.

20. AUDIT

20.1 Purpose

20.1.1 Auditing provides an independent, unbiased assessment of integrity activities. The fundamental purpose of auditing is to ensure that deviations from expected procedures are identified in order to enable corrective actions and continual improvement to take place within Company.

20.1.2 Audits also demonstrate to management the performance of the integrity management systems in delivering best practice integrity management.

20.1.3 Audits within the Company shall have the following key objectives:

a. To ensure compliance with all relevant National Legislation;
b. To ensure compliance with all relevant Regulations, Codes and Standards including:
    b1. International Codes and Standards;
    b2. Company Standards;
c. To ensure that integrity management objectives are being met;
d. To drive continuous improvement.

Auditing provides a fundamental element to all of the Integrity Management Systems.

20.2 Custodians

The Quality Assurance department is the Custodian of Audit within the Company.

This centralized function will ensure that all audits are carried out in a consistent manner following Company Guidelines.

Further details of Auditing Procedures are also covered in Company Health, Safety and Environmental Management System Manual

20.3 Audit Process

The following process applies to audits carried out within the Company.

20.3.1 Identification of Audits

The Audit program shall be developed on the basis of:

a. The results from risk assessments;

b. The results of previous audits;
c. The status and importance of the activity being undertaken;
d. Areas of concern identified by the Assets;
e. To ensure that all activities on all Assets are considered.

20.3.2 Terms of Reference

The terms of reference for all audits shall be established and agreed by ID and QA prior to its commencement.

20.3.3 Scheduling

The Audit program is developed on an annual basis, although is subject to ongoing review and adjustment.

20.3.4 Planning & Auditors

Audits shall be carried out by persons who do not have any direct responsibility for the work in the area to be audited.

Selection of Auditors shall be determined according to their individual experience and competence. Where considered necessary, third party Auditors will be used.

Dates and Scope of the audit shall be communicated as appropriate to all relevant parties.

20.3.5 Carrying out the Audit

The following steps shall be carried out:

a. Entry Meeting – Between the Auditor and the Representatives of the area to be audited. The meeting will discuss the audit scope, itinerary, agenda, and in the case of Sub-contractor audits, escorts and the required level of co-operation shall be obtained.
b. Conducting the Audit – The Auditor shall look for evidence of compliance and non-compliance in accordance with the terms of reference and scope of the audit. Audit findings shall be brought to the attention of the audited at the time that the finding is made. Non-Conformity Notes (NCN) shall be raised as applicable (e.g. where there is objective evidence of the absence of, or departure from, approved procedures).
c. Exit Meeting – The Auditor presents their findings and shall ensure that the Audited understands the problems highlighted.
d. Further details for Auditing check list are covered in Appendix-J.

20.3.6 Reporting

The Auditor shall prepare and submit a report on the findings of the audit to QA, ID and the audited area.

20.3.7 Corrective Actions

The Audited enters the proposed corrective action to be taken and a date for completion is agreed or noted. Upon completion of the said corrective action, the Audited shall sign and date their copy and return a signed copy to the Auditor.

20.3.8 Follow up Actions

The Auditor shall produce a schedule for any follow-up audits which may be necessary. The follow-up audits shall be carried out as close as possible to the established due dates for implementation of NCNs as is practicable.

20.4 Audit Follow-Up and Action Tracking

Audit findings shall be entered into the Company action tracking system.

21. DOCUMENT ADMINISTRATION

This section outlines the administration process for maintaining and updating the PIMS.

21.1 Auditing and Compliance

A 2-year rolling action plan will be developed by the IA and updated bi-annually to monitor and update the PIMS as a result of operations and feedback.

21.2 Administration and Authorization

The overall responsibility and authority for maintaining the PIMS is the IA.

21.3 Document Review, Changes and Amendments

The PIMS shall be reviewed on an annual basis following the technical assessment and provision of recommendations from Contractors and Company staff. Input from technicians, engineers and external sources should be part of this process and should be encouraged. If however, at any time, any user identifies an error or has a suggestion for improvement then they can raise the query to the custodian using the relevant procedure. The custodian contact details are stated at the front of the document.

The PIMS should be challenged to determine whether it operates effectively and if it still fits the asset unit needs if they have changed.

The IA shall be responsible for the review of the PIMS. The IA shall ensure it remains appropriate in the light of each year's findings. The results of the review shall be included in the annual report prepared by the IA as a formal record of the review.

21.3.1 Review Input

a. Results of audits for internal, supplier and certification.

b. Results of process compliance evaluation checks.
c. Installation feedback, complaints, surveys etc.
d. Industry initiatives including Step Change.
e. Process performance.
f. Status of corrective and preventive actions including initiatives.
g. Follow-up from previous management reviews including current HSEQ plan performance.
h. Changes that could affect the management system including legislative changes
i. Recommendations for improvement.

21.3.1 <u>Review Output</u>

Decisions and actions related to:

a. Improvement of the effectiveness of the management system;
b. Improvements related to products and service;
c. Any resource needs addressed;
d. Assurance Plan for the next period;
e. Audit plans for the next period;
f. Management Review actions logged;
g. Minutes of the meeting signed by the senior person present at the meeting.

21.4 <u>Document Control</u>

The control of this document shall comply with relevant procedure which will specify the procedures for:

a. Authorization and Approval Process;
b. Document Designation Category;
c. Document Numbering and Revisions Process;
d. Document Distribution and Control Stamp;
e. Document Copyright;
f. Document Terms and Conditions of Use

APPENDIX A- INTEGRITY ASSURANCE ACTIVITIES

Lifecycle Stage	IM & VAP Stage	Assurance Activity	Department Responsible	Records
Policy	Policy & Strategic Objectives	IM Policy	ID	IM Policy Document
		Maintenance Policy	MD	Maintenance Policy Document
Design & Construction	Design & Construction Process **(Define & Execute)**	Requirements for Line pipe	PMT	Line pipe Specification
		Materials for Sour Service	PMT	Material Selection Report
		Pipeline and Other Valves	PMT	Pipeline and Valve Specification and Datasheets
		Specification for Line pipe pt3, Induction Bends	PMT	Induction Bend Specification
		Polypropylene Coating	PMT	Coating Specification
		Neoprene Coating	PMT	Coating Specification
		Field Joints for Polypropylene Coating	PMT	Field Joint Specification
		Corrosion Protection Coating	PMT	Coating Specification
		Pipeline Cleaning, Flushing and Flooding	PMT	Pipeline Cleaning Report
		Hydrostatic Testing of Subsea Pipelines	PMT	Hydrotest Specification and Completion Certificate
		Water Quality for Hydrotest	PMT	Water Quality Specification
		Concrete Weight Coating for Subsea Pipelines	PMT	Weight Coating Specification
		Pipeline Welding	PMT	Approved Welding Procedures
		Access Fittings of Corrosion Monitoring & Chemical Injection	PMT	Access Fitting Specification
		Offshore Survey of Subsea Pipelines	PMT	Survey report
		Specification for Submarine Pipeline Systems	PMT	Subsea Pipeline Specification
		Protection requirements of Subsea Pipelines	PMT	Specification of protection requirement
		Subsea Pipeline Crossing	PMT	Crossing Design Report
		Buckling of Subsea Pipelines	PMT	Buckling Report
		On Bottom Stability of Subsea Pipeline	PMT	Stability Report
		Offshore Trenching and Backfilling	PMT	Trenching and Backfill Specification
		Shore Approach of Subsea Pipelines	PMT	Shore Approach Spec
		Constructability Review of Subsea Pipelines		Constructability risk assessment
		Operations , Maintenance & Integrity Philosophy	PMT/ID	HSECES Corrosion Management Strategy Inspection Requirements

Lifecycle Stage	IM & VAP Stage	Assurance Activity	Department Responsible	Records
		Materials Selection Philosophy	PMT/DED/ID	Materials Selection Philosophy
	Risk Identification **(Select, Define & Execute)**	Pipeline Risk Assessment Risk Register	PMT/DED/ID	Risk Assessment Documents Risk Register
		Identify HSE	PMT/DED/ID	HSE Register
	Establish Risk Management Plan **(Select, Define & Execute)**	Corrosion Management Plans	PMT/DED/ID	Corrosion Management Plans
		Performance Standards and Written Schemes of Examination	PMT/DED/ID	Performance Standards and Written Schemes of Examination
		Dead Leg Register	PMT	Dead Leg Register
	OMI&M **(Execute & Operations)**	Baseline inspection	PMT/ID	Baseline Inspection Report
	Build Trends, Learn & Improve **(Define & Execute)**	QA/QC Records Certification	PMT/QA/QC	QA/QC Certificates
	Handover **(Execute)**	Asset Register Preparation	PMT	Asset Information Dossier DFI Dossier Design Data Construction Data As built Drawings Records of Changes/Mods Operations Manuals Commissioning Certificates?
		Pre-Commissioning, Commissioning & Handover of Projects	PMT/OPS	Commissioning report
		Operations Manual & Procedures Requirements	PMT/OPS	Operations Manuals
		Dead Legs Register	PMT	Dead Leg Register
		Project Deliverables	PMT	
		Technical Specification Data Pipeline Data Sheets	PMT	Pipeline Datasheets
Operations	Risk Identification **(Operations)**	Passport - Qualitative & Quantitative	ID	Passport Report
	Establish Risk Management Plan **(Operations)**	Subsea Inspection Plan	ID	Inspection Plan
		IP Inspection Plan	ID	Inspection Plan
		Risk management of Subsea Pipelines	ID	Risk Report
	Operations, Maintenance Integrity &	Maintenance Strategy	TSD	N/A
		Topside Pipe work Inspections	ID	Inspection Report

Lifecycle Stage	IM & VAP Stage	Assurance Activity	Department Responsible	Records
	Mitigation **(Operations)**	Riser Clamp/Splash Zone Inspection	ID	Inspection Report
		Pipeline ROV inspection	ID	Inspection Report
		Pipeline IP Inspection	ID	Inspection Report
		Pipeline CSS - ESDVs	ID	
		Pipeline CSS - ESDV Fire Protection	ID	Inspection Report
		Dead leg inspection	ID	Inspection Report
		Inspection of Concrete Support - Main	ID	Inspection Report
		Corrosion monitoring - probes	OPS/ID	Inspection Report
		Corrosion monitoring - coupons	OPS/ID	Inspection Report
		Production - sampling	OPS	Sampling Report/Log
		Pig trap - sampling	OPS	Sampling Report/Log
		Production chemistry - water	OPS	Sampling Report/Log
		Water injection - sampling	OPS	Sampling Report/Log
		Sampling Systems	OPS	Sampling Report/Log
		Flushing/Chemical cleaning	OPS	Flushing/Cleaning Report/Log
		Corrosion Inhibitor Injection	OPS	Injection Records/Log
		Water injection pipelines - biocide/scale etc. chemical treatment	OPS	Injection Records/Log
		Mothballing of Pipelines	OPS/ID	
	Assessment **(Operations)**	QC - Issue Pipeline Certificate	ID	Pipeline Certificate
		Anomaly assessment	ID/DED	Assessment Reports
		FEA of Damaged Pipeline	DED	FEA Report
	Intervention, Repair and Emergency Response **(Operations)**	Coating campaign of Pipeline Risers	MD	Coating Report
		Free Span Correction	ID	Free Span Report
		Cathodic Protection - Sacrificial Anode replacement	ID	Anode Replacement Report
		Riser/Riser Clamp - Campaign	ID	Repair Report
		Subsea Pipeline Repair	ID	Repair Report
		Dead Leg Replacement Pipework	MD/TSD	Dead Leg replacement Report
		Composite Repair	ID	Repair Report
		Riser Repair by Composite Materials	ID	Repair Report
		Riser Repair by Metallic Materials	ID	Repair Report
		Pipeline Repair Clamps	ID/TSD	Repair Report

Lifecycle Stage	IM & VAP Stage	Assurance Activity	Department Responsible	Records
		Pipeline Mechanical Connector Spool	ID	Repair Report
		Call off contract support repairs	ID	Repair Report
		Maintain materials inventory to support repairs	ID	Material Inventory
	Build Trends, Learn & Improve (**Operations)**	KPI Reports	ID	KPI Reports
		Build Trends	ID	Integrity Status Reports/Trend Reports
		Lessons Learned	ID	Lessons Learned Report

APPENDIX B: PIPELINE SYSTEM THREATS

Threat Group	Threat
	Design errors
DFI threats	Fabrication related
	Installation related
	Internal corrosion
Corrosion/erosion threats	External corrosion
	Erosion
	Trawling interference
	Anchoring
	Vessel impact
Third party threats	Dropped objects
	Vandalism / terrorism
	Traffic (Vehicle impact, vibrations)
	Other mechanical impact
	Global buckling (exposed)
	Global buckling (buried)
Structural threats	End expansion
	On-bottom stability
	Static overload
	Fatigue (VIV, FIV, waves or process variations)
	Extreme weather
	Earthquakes
	Landslides
Natural hazard threats	Ice loads
	Significant temperature variations
	Floods
	Lightning
	Incorrect procedures
	Procedures not implemented
Incorrect operation threats	Human errors
	Internal protection system related
	Interface component related

APPENDIX C: PIPELINE PASSPORT

Pipeline PASSPORT is an Executive summary report which consists of a number of components:

a. Technical and Business Risk Assessments;
b. Pipeline Replacement;
c. Mitigation and repair;
d. Innovation.

A Pipeline PASSPORT can be generated for both pigged and un-pigged lines and examples of both are provided below.

Pipeline PASSPORT consists of a two page summary sheet which summarises the latest status of a specific pipeline. It shall be the basis for any action or recommendation relevant to that pipeline.

Pipeline PASSPORT has the following key benefits to the Company:

a. Standard and consistent methodology for assessing pipeline integrity;
b. Ranking of pipelines by risk to prioritise inspection and mitigation;
c. Provides justification for investment particularly pipeline replacement;
d. Assures production targets are met with no surprises.

APPENDIX D: Risk Assessment and Integrity Management Planning **(Common corrosion threats)**

Corrosion threat	*Initiator*	*External See Note 1*	*Internal See Note 3*	*Time dependency*	*Note*
O_2-corrosion	O_2 + water	o	x	Time dependent	1, 3
CO_2-corrosion	CO_2 + water	NA	x	Time dependent	1, 3,7
Top of line corrosion	CO_2 + water	NA	x	Time dependent	1, 3, 7
Preferential weld corrosion	CO_2 + water	NA	x	Time dependent	1, 3, 7
General H_2S-corrosion	H_2S + water	NA	x	Time dependent	1, 2, 3
Sulphides stress cracking (SSC)	H_2S + water	(x)	(x)	Abrupt	1, 2, 3
Stress corrosion cracking (SCC)	H_2S + chloride/oxidant + water	(x)	(x)	Abrupt	1, 2, 3
Hydrogen induced cracking (e.g. HIC)	H_2S + water	(x)	(x)	Abrupt	1, 2, 3
Microbiologically influenced corrosion (MIC)	Microorganism + water + organic matter often in combination with deposit	o	x	Time dependent	1, 3, 4
Corrosion-erosion	Produced sand + O_2 / CO_2 + water	NA	x	Time dependent	1, 3
Under deposit corrosion	O_2 / CO_2 + water + debris/ scaling	NA	x	Time dependent	1, 3
Galvanic corrosion	O_2 / CO_2 + water	o	x	Time dependent	1, 3
Elemental sulphur	(H_2S + O_2 + water) / (S + water)	NA	x	Time dependent	1, 3
Carry-over of glycol	(H_2S +O_2 + water) / (CO_2 + water)	NA	x	Time dependent	1, 3
Hydrogen induced stress cracking (HSIC)	Cathodic protection + load/ stress + susceptible material	x	NA	Abrupt	1, 3, 5
Acid corrosion	Acid	NA	x	Time dependent	1, 3, 6

1) External corrosion of submarine pipeline shall be controlled by the application of external corrosion coating in combination with cathodic protection (CP). Galvanic corrosion will be eliminated by cathodic protection.
2) Corrosion control through materials selection and qualification according to ISO-15156. Applicable both for internal and external.
3) Aggravating factors with regards to internal corrosion may be: Lack of control with chemical injections for corrosion control Presence of organic acids
Scaling and deposits in the pipeline.
4) Depending of the operating conditions, corrosion prevention strategy and reservoir conditions MIC can be caused by various kinds of microbial consortia on internal surfaces of pipelines. MIC is rarely caused by one single type of microorganism – but in complex consortia of several types of microorganisms called biofilms. Additionally, MIC is often seen in combination with other corrosion threats such as e.g. under-deposit corrosion and erosion. Of primary concern is sulphate reduced bacteria (SRB), sulphate reducing archaea (SRA) and methanogens. SRB/SRA's produces H2S through their metabolism. See Note 2. Methanogens can drive the corrosion process directly on the metal surface and produce methane.
5) Susceptible linepipe materials are: 13Cr, 22Cr, 25Cr and high strength steels.
6) Chemicals for cleaning of the pipeline internally.
7) Corrosion resistant alloys are considered fully resistant to CO2 corrosion in an oil and gas production system.

NA -not applicable

X: probable threat

(x) *Internal*: very low probability due to the general requirement for materials resistance to sour service under such conditions (see also note 2)

External: In seabed sediments there will always be some H2S production due microbiologically activity. It appears to be no indication that this has caused cracking due to H_2S.

O: very low probability, due to the application of an external corrosion protection system (coating and CP).

APPENDIX E: CORROSION MONITORING TECHNIQUES

Monitoring techniques		*Classification*		*Comment*
Corrosion probes	Weight loss coupons (Flush mounted or probes extended into the fluid)	Direct	Intrusive	Require access through wall. Gives information related averaged corrosion rate over a certain time period.
	Linear Polarisation Resistance (LPR) 1)	Direct	Intrusive	Require access through wall. Gives real time corrosion rate at a specific location
	Electrical Resistance (ER) 1)	Direct	Intrusive	Require access through wall. Gives real time corrosion rate at a specific location
	Hydrogen probes 2)	In-direct	Intrusive	On-line monitoring of hydrogen
	Galvanic probes 1)	Direct	Intrusive	Require access through wall: Gives information on real time monitoring. Measure galvanic currents.
	Bioprobes	Direct	Intrusive	Require access through wall. Real time measurement.
Advance Electrochemical Techniques	Impedance spectroscopy Electrochemical noise	Direct	Intrusive	Require access through wall. Gives real time measurements.
Fluid analysis	For details see Appendix 4	In-direct	Non-intrusive	Off-line measurements. Sampling for laboratory examination
		Direct	Intrusive	On-line/real time measurement of e.g. oxygen, pH, oxidising reduction potential.
Field signature method	Wall thickness measurements	Direct	Non-intrusive	On-line, or scheduled (i.e. by ROV), measurement of internal corrosion recorded from the pipe outer surface.
NDT (Ultrasonic testing UT)	Wall thickness measurements	Direct	Non-intrusive	Wall thickness measurements by portable equipment or permanently installed equipment. Measurements taken from the external surface at a specific location on top side piping
Radiography	Wall thickness measurements	Direct	Non-intrusive	Measurements taken from the external surface at a specific location on top side piping
Video camera/ boroscope	Identification of corrosion damage	-	'Intrusive'	Visual inspection that can be used to locate internal corrosion
Long range ultrasound/ guided wave	Screening technique for identification of metal loss/ corrosion	Direct	Non-intrusive	Method for screening of defects along a pipe / pipeline. The method does not quantify the defect but may detect if defects are located along the pipeline for a given length. Require access to pipe steel

a. The techniques will require a conductive water phase. The probes may be affected by fouling, formation of a biofilm, hydrocarbon and other deposits
b. Extent of hydrogen diffusion for systems containing H2S

APPENDIX F: PROCESS MONITORING AND INTERNAL CORROSION CONTROL

Process parameter	Parameter	Dry gas (export/gas lift)	Wet gas	Multi-phase (production)	Crude oil (export)	Injection Water
Operational parameters	Pressure	online	online	online	online	online
	Temperature	online	online	online	online	online
	Flow rates (oil/gas)	online	online	online	online	online
	Water cut			online	online	
Chemical injection	Biocides			(x)	(x)	(x)
	Inhibitors (e.g. scale/wax/corrosion)	(x)	(x)	(x)	(x)	(x)
	Glycol - methanol	(x)	(x)	(x)		
	pH-buffering chemicals			(x)		
	Scavengers	(x)				(x)
	Dispersants			(x)		
	Others [1)]	(x)	(x)	(x)	(x)	(x)
1) E.g. chemicals used for down periods or cleaning online monitoring - Required						
(x) Continuously or batch wise injection (injection rate/volume)						

APPENDIX G- PIPELINE THREATS & INTEGRITY ACTIVITIES MATRIX

Offshore Pipeline Integrity Threats		Service				Integrity Management Activities																			
						Monitoring							Mitigation									Inspection			
							Internal			External			Internal					External							
Group Threats	Specific Threats	Oil Lines	Water Lines	Gas Lines	Condensate Lines	Corrosion rate	Water analysis	Pig trash/fluid analysis	Chemical injector checks	Direct measurement	ROV survey	Cathodic protection survey	Operational pigging	Continuous corrosion inhibitor injection	Batch corrosion inhibitor injection	Continuous biocide injection	Batch biocide injection	Anti corrosion coating	Cathodic protection system	Casing	Signage/buoy	Intelligent pigging (MFL?UT)	Intelligent pigging (calliper)	Direct assessment	ROV survey
Internal Corrosion	Acid gas corrosion (CO2/H2S)	✓	✓	✓	✓		✓	✓	✓				✓	✓	✓							✓			
	Oxygen Corrosion		✓				✓	✓	✓				✓	✓	✓							✓			
	Microbiological Induced Corrosion	✓	✓	✓	✓	✓	✓	✓	✓				✓			✓	✓					✓			
	Sulphide Stress Corrosion Cracking		✓				Event Driven Activities																		
	Hydrogen Induced Cracking	✓		✓			Event Driven Activities																		
	Erosion Corrosion		✓	✓		✓							✓									✓			
	Crevice Corrosion	✓	✓	✓	✓		Event Driven Activities																		
	Galvanic Corrosion	✓	✓	✓	✓		Event Driven Activities																		
	Chemical Corrosion	✓	✓	✓	✓		Event Driven Activities																		
External Corrosion	Atmospheric Corrosion	✓	✓	✓	✓	✓				✓	✓	✓						✓	✓			✓		✓	
	Subsea Corrosion	✓	✓	✓	✓	✓				✓		✓						✓	✓			✓		✓	✓
	Stress Corrosion Cracking	✓	✓	✓	✓	✓				✓		✓						✓	✓					✓	✓
	Corrosion under insulation	✓	✓	✓	✓					✓								✓				✓			
	Corrosion at riser clamp transition	✓	✓	✓	✓					✓								✓				✓			
	Crevice Corrosion	✓	✓	✓	✓		Event Driven Activities																		
	Galvanic Corrosion	✓	✓	✓	✓		Event Driven Activities																		
	Coating failure	✓	✓	✓	✓							✓						✓	✓			✓			✓
	Attachments	✓	✓	✓	✓													✓				✓		✓	
	Riser Splash Zone Corrosion	✓	✓	✓	✓					✓		✓						✓	✓	✓		✓		✓	

Offshore Pipeline Integrity Threats		Service				Integrity Management Activities																			
						Monitoring							Mitigation									Inspection			
							Internal			External			Internal					External							
Group Threats	Specific Threats	Oil Lines	Water Lines	Gas Lines	Condensate Lines	Corrosion rate	Water analysis	Pig trash/fluid analysis	Chemical injector checks	Direct measurement	ROV survey	Cathodic protection survey	Operational pigging	Continuous corrosion inhibitor injection	Batch corrosion inhibitor injection	Continuous biocide injection	Batch biocide injection	Anti corrosion coating	Cathodic protection system	Casing	Signage/buoy	Intelligent pigging (MFL?UT)	Intelligent pigging (calliper)	Direct assessment	ROV survey
3rd Party Damage	Dropped Anchor	✓	✓	✓	✓					✓	✓										✓				✓
	Dragged Anchor	✓	✓	✓	✓					✓	✓										✓				✓
	Crossing	✓	✓	✓	✓					✓	✓										✓				✓
	Explosion (seismic survey)	✓	✓	✓	✓					✓	✓										✓				✓
Natural Hazards	Free spanning	✓	✓	✓	✓	Event Driven Activities																			
	Seismic activity	✓	✓	✓	✓	Event Driven Activities																			
	Extreme weather related	✓	✓	✓	✓	Event Driven Activities																			
Material & Manufacture related	Material failure	✓	✓	✓	✓	Event Driven Activities																			
	Seam weld failure	✓	✓	✓	✓	Event Driven Activities																			
	Girth weld failure	✓	✓	✓	✓	Event Driven Activities																			
	Installation damage	✓	✓	✓	✓	Event Driven Activities																			
	Gaskets/O-rings failure	✓	✓	✓	✓	Event Driven Activities																			
	Pump/valve packing failure	✓	✓	✓	✓	Event Driven Activities																			
	Fatigue	✓	✓	✓	✓	Event Driven Activities																			
	Vibration	✓	✓	✓	✓	Event Driven Activities																			
	Buckling	✓	✓	✓	✓						✓										✓				✓
Operations	Incorrect Operations	✓	✓	✓	✓	Event Driven Activities																			
	Pressure Control	✓	✓	✓	✓	Event Driven Activities																			

APPENDIX H:

LIST OF LEGISLATION AND INTERNATIONAL REGULATIONS

1. LOCAL Legislation (to be finalized prior to project commencement)
2. International Regulations and Codes of Practice
   a. DNV Standards & Recommended Practices
   b. Energy Institute Guidelines for Management of Integrity of Subsea Facilities

APPENDIX I: PIPELINE INTEGRITY ASSURANCE PLAN

The integrity plans should be succinct and captured on 1 or 2 pages. The plans are the key to proactive management of people, process and plant to assure integrity. The plans will form the basis of audits and management reports.

Integrity Assurance Plan Template

APPENDIX I1: INTEGRITY ASSURANCE PLAN TEMPLATE

Integrity Assurance Plan	***Equipment Type***	***Division***	***Year***	***Status***	***Pages***
	e.g. Lifting	e.g. Drilling			Page X of Y

ACTIVITIES FORECAST		***TARGETS***			***RECORDS***		***STATUS***		
No	***Activities***	***Target***	***By When***	***By Who***	***Resources***	***Standards***	***Records Done***	***Status***	***Instructions***
1									1. Input Standard details. 2. List all the forecasted activities that require integrity assurance including activities which contribute to integrity assurance directly keeping the activities cycle below in mind. 3. Fill in the targets and dates for each activity keeping the targets cycle below in mind. 4. Fill in the person accountable for each activity 5. Fill in the Resources (Training, Staff, Contractors, Expertise, Knowledge, Budgets) required 6. Fill in the applicable standards and record whether they are completed and available (✓/✗) 7. Indicate integrity assurance status integrity with traffic light Green = Integrity Assured Orange = In progress Red = Needs to be focused on Yellow = Non-critical 8. For all activities which are not „green" status an action should be listed in the „areas of attention„along with dates and risks to completion. 9. All management/SH reporting events should be listed in the management reporting section along with dates and actions required.
2									
3									
4								○	
5								○	
6								○	
7								○	
8								○	
9								○	

Areas of Attention Required				***Management reporting***					
No	***Required Action***	***By When***	***Risks***	***Next Report***	***Date***	***Action Required***	ACTIVITIES	***Integrity Assurance Plan Details***	
1								***Next Revision***	
2								***Last Revised***	
3								***Reference***	
							TARGETS	***IA***	
								Signature	
								Approver	
								Signature	

APPENDIX J: EXAMPLE AUDIT CHECK SHEET

No.	***Question***	***Comments***	***Yes***	***No***
Policy/Process				
1	*Is the integrity management policy available, approved, current and publicly displayed?*			
2	*Is the PIMS available, approved, current and publicly displayed?*			
3	*Is the PIMS process periodically reviewed, benchmarked and updated?*			
4	*Is the SPA aware of the PIMS and its contents?*			
5	*Are the PIMS goals and objectives clearly stated and understood?*			
6	*Is the PIMS easily available?*			
7	*Is the workforce aware of the PIMS contents?*			
Organization, Roles and Responsibilities				
8	*Are the roles and responsibilities defined?*			
9	*Are the defined roles aware of their responsibilities?*			
10	*Are the applicable persons competent?*			
11	*Are sufficient personnel available to implement the PIMS effectively and efficiently?*			
12	*Do organization charts exist, showing clear lines of responsibility?*			
13	*Is the workforce aware of their responsibilities?*			
Training & Competency				
14	*Are personnel sufficiently trained, qualified and competent to carry out their jobs?*			
15	*Is there access to a known technical expert in required area of functional expertise?*			
16	*Are the IA and TA aware of their responsibility for training and competence assurance?*			
17	*Are the Divisional and Line Managers aware of their responsibility for training and competence assurance?*			
18	*Are spot checks of training and competency carried out?*			
19	*Is a training record available?*			
Risk Assessments and Critical Records				
20	*Are risk assessments being carried out?*			
21	*Is there a Pipeline PASSPORT available for every pipeline?*			
22	*Is the IA aware of their responsibilities for storing and maintaining Critical Records?*			
23	*Is Data base system up to date with all equipment identified?*			

Maintenance & Inspection				
24	*Has an inspection plan been developed by the Inspection Authority?*			
25	*Is the inspection plan based on the risk assessments in Pipeline PASSPORT?*			
26	*Is the specification to the inspection vendors based on the POF?*			
27	*Are anomalies discovered during IP inspections subjected to validation?*			
28	*Are inspection results recorded?*			
Building Trends				
29	*Are there a set of defined metrics or measures for which trending is carried out?*			
30	*Are trends reported on a regular basis?*			
31	*Is there a nominated person responsible for trending analyses?*			
Management of Change				
32	*Have any modifications been made to the pipelines in the last 12 months?*			
33	*Are records of these modifications available?*			
34	*Where applicable, has the equipment been correctly signed off for dismantling, disposal and written off as per Procedures .*			
35	*Is there management of change procedures in use in accordance with the PIMS?*			
36	*Where applicable have the procedures for deviations been followed and approved by the TA?*			
37	*Are any changes or modifications that may affect emergency response to major accidents fed back to the emergency response risk register and procedures?*			
Emergency Response				
38	*Do all relevant personnel know how to respond to a pipeline emergency?*			
39	*Are the emergency response procedures clearly documented and available?*			
Incident Investigation				
40	*Have any pipeline incidents occurred in last 12 months?*			
41	*Are all pipeline incidents investigated?*			
42	*Are the results and lessons learned made known to the work force?*			
43	*Have any near miss reports been filed in the last 12 months?*			
Audits and KPI Reports				
44	*Has the forgoing audit assessment been conducted in the last 12 months?*			

APPENDIX-K: RACI CHART

ACTIVITY	Integrity Authority	Technical Authority	Inspection Authority	Subsea Maintenance & Repair Authority	Topsides Maintenance & Repair Authority	Materials and Corrosion Authority	Integrity Coordinator	Asset Manager	Project Manager	HSEQA Division
Integrity Assurance Process • Assure IM cycle is implemented across COMPANY • Assure Integrity Standards, Guidelines etc. are in place	A A	C C					R R	I I	I I	I I
Roles and Responsibilities • Assign and agree Roles and Responsibilities • Inform relevant individuals in RACI chart	A/R A	C C	I I	I I		I I	I R	C C	C C	
Critical Records • Assure Critical Records are stored and maintained • Assign responsibilities to manage Critical Records • Assure Critical records are integrated into IDBMS	A A/R A/R	R R R	R R R	R R R		R	I I I	R R	R R	
Competence Assurance • Agree RACI chart for Competency Assurance • Inform individuals of their Roles and Responsibilities	A A/R	C C					I I	C C	C C	
Integrity During Projects • Ensure Projects are engaged in IA process • Support VAP through Integrity input to VIP reviews • Develop Project ID interface process	A A A	C C				R R			R C C	
Pipeline Operations • Inform Operations of their Roles and Responsibilities • Liaise with Operations for Inspection activities	R C	I	I R	I	I			A C		
Pipeline Risk Assessments • Undertake PASSPORT assessments	A	R	C			C	I	C	C	
Inspection and Monitoring • Develop Inspection plan • Undertake inspections • Evaluate results	A A A	C I C	R R R				I I I	C C I		
Assessment • Undertake a Fitness for Purpose assessment • Manage anomalies	A A	R C	C R	C R	C C	R C	I I	I C		
Intervention and Repair • Evaluate and select option • Seek approval for repairs/intervention • Undertake intervention or repair	A A/R A	C C I		R C R	C C C		I I I	C C I		
Asset Replacement Plans/Strategies	A	R	R	R	R	C	I	C	C	
Prevention and Mitigation • Plan Prevention and Mitigation activities • Implement activities • Assure implementation is undertaken	A A A/R			C C C	C C C		I I I	R R C		

ACTIVITY	Integrity Authority	Technical Authority	Inspection Authority	Subsea Maintenance & Repair Authority	Topsides Maintenance & Repair Authority	Materials and Corrosion Authority	Integrity Coordinator	Asset Manager	Project Manager	HSEQA Division
Mothballing and Abandonment • Agree pipelines to be mothballed/abandoned • Assure mothball/abandon activities undertaken	A A/R	C C					I I	R C	R C	
Management of Change • Assure MOC process being implemented	A						R			
Emergency Response • Manage EPRS	A	C	R					C		
Incident Investigation • Set up Incident Investigation team • Address findings of team	A/R A	C C						C R	C R	
KPI, Build Trends	A	C	C	C	C	C	R	C	C	C
Audit/Verification • Identify programme of audits • Plan and facilitate audits - (HSEQA) • Track audit actions	A A A	I I I					R I R	C C C		R R R

Key

A	Accountable
R	Responsible
C	Consulted
I	Informed

APPENDIX –L ABBREVIATIONSAbbreviation	Description
CoF	consequence of failure
CP	cathodic protection
CVI	close visual inspection
DEH	direct electrical heating
DFI	design fabrication installation
DFO	documents for operation
EPRG	European pipeline research group
ER	electrical resistance
FEA	finite element analysis
FIV	flow induced vibrations
FMEA	failure modes and effects analysis
FSM	field signature method
GVI	general visual inspection
GRP	glass reinforced plastic
HAZOP	hazard and operability analysis
HIPPS	high integrity pressure protection system
HSE	health safety and the environment
IA	integrity assessment/ integrity authority
IDBMS	integrity data base management system
ILI	in-line inspection
IM	integrity management
IMP	integrity management process
IMR	inspection, maintenance and repair
IMMR	inspection, maintenance, monitoring and repair
IMS	integrity management system
IP	intelligent pigging
KP	kilometer point
LPR	linear polarisation resistance
MIC	microbiologically influenced corrosion
MIR	mitigation, intervention and repair*
MFL	magnetic flux leakage
NCN	non conformity notes
NCR	non conformances report
NDT	Non-destructive testing
PDAM	pipeline defect assessment manual
PIMS	pipeline integrity management system
PoF	probability of failure
RBI	risk based inspection
RLA	remnant life assessment
ROV	remote operated vehicle
RP	recommended practice
SPA	single point accountability
TA	technical authority
TQ	technology qualification
UT	ultrasonic testing
UTM	universal transverse mercator
VIV	vortex induced vibrations
QRA	quantitative risk analysis

APPENDIX-M: DEFINITIONS

term	Definition
abandonment	activities associated with taking the system permanently out of service
acceptance criteria (i.e.) design limits)	specified indicators or measures providing an acceptable safety level and that are used in assessing the ability of a component, structure, or system to perform its intended function The acceptance criteria should be quantifiable.
commissioning	activities associated with the initial filling of the pipeline system with the fluid to be transported, and is part of the operational phase
commissioning, de-	activities associated with taking the pipeline temporarily out of service
commissioning, re-	activities associated with returning a de-commissioned pipeline to service
crack:	a planar, two-dimensional feature with displacement of the fracture surfaces
design life	The design life is the period for which the integrity of the system is documented in the original design. It is the period for which a structure is to be used for its intended purpose with anticipated maintenance, but without requiring substantial repair.
failure	an event affecting a component or system and causing one or both of the following effects: — loss of component or system function; or — deterioration of functional capacity to such an extent that the safety of the installation, personnel or environment is significantly reduced.
in-service	the period when the pipeline system is under operation
in-service file	a system for collection of historical data for the whole service life
integrity control	activities to verify the integrity of a pipeline with respect to pressure containment Covers both internal and external activities.
oil & gas	content in pipe may be either oil or gas
operation	the day to day operation as defined in [3.4]
operator	the party ultimately responsible for operation, and the integrity, of the pipeline system
pig	device that is driven through a pipeline for performing various internal activities (depending on pig type) such as to separate fluids, clean or inspect the pipeline
pig, intelligent	pig that can perform non-destructive examinations
pipeline integrity	the ability of the system to operate safely and to withstand the loads imposed during the system life cycle
re-qualification	re-assessment of design due to modified design premises and/or sustained damage
	E.g. life extension is a design premise modification.
risk	the qualitative or quantitative likelihood of an accidental or unplanned event occurring considered in conjunction with the potential consequence of such a failure In quantitative terms, risk is the quantified probability of a defined failure mode times its quantified consequence.
risk management	the entire process covering identification of risks, analysing and assessing risks, developing
	plans to control risks, and implementation and monitoring to evaluate effectiveness of the controls in place
service life	the time length the system is intended to operate The service life is a part of the application toward authorities.
supplier	an organization that delivers materials, components, goods, or services to another organization
take-over	is defined as the process of transferring operating responsibility from the project phase (up to an including pre-commissioning) to operations
threat	an indication of an impending danger or harm to the system, which may have an adverse influence on the integrity of the system.

APPENDIX-N: Referenced standards

DNV GL standards and recommended practices	
DNV-OS-F101	*Submarine Pipeline Systems*
DNV-RP-F101	*Corroded Pipelines*
DNV-RP-F103	*Cathodic Protection of Submarine Pipelines by Galvanic Anodes*
DNV-RP-F105	*Free spanning Pipelines*
DNV-RP-F107	*Risk assessment of Pipeline Protection*
DNV-RP-F109	*On-Bottom Stability Design of Submarine Pipelines*
DNV-RP-F110	*Global Buckling of Submarine Pipelines Structural Design due to High Temperature /High Pressure*
DNV-RP-F113	*Pipeline Subsea Repair*
DNV-RP-F206	*Riser Integrity Management*
DNV-RP-F302	*Selection and Use of Subsea Leak Detection Systems*
DNV-RP-H101	*Risk Management in Marine and Subsea Operations*
DNV-RP-J202	*Design and Operation of CO2 Pipelines*
DNV-RP-O501	*Erosive Wear in Piping Systems*
DNVGL-RP-0002	*Integrity management of subsea production systems*
DNVGL-RP-0005	*DNV-RP-C203: Fatigue design of offshore steel structures*

International standards and recommended practices	
ISO/TS 12747:2011	*Petroleum and natural gas industries -- Pipeline transportation systems Recommended practice for pipeline life extension*
ISO 13623	*Petroleum and Natural Gas Industries – Pipeline Transportation Systems*
ISO 14224	*Petroleum, petrochemical and natural gas industries – Collection and exchange of reliability and maintenance data for equipment*
ISO 16708	*Petroleum and natural gas industries – Pipeline transportation systems – Reliability-based limit state methods*
ISO 17776	*Petroleum and natural gas industries - Offshore production installations - Guidelines on tools and techniques for hazard identification and risk assessment*
ISO 55000	*Asset management - Overview, principles and terminology*

Other references	
API RP 1110	*Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids, or Carbon Dioxide*
API RP 1160	*Managing System Integrity for Hazardous Liquid Pipelines*
API RP 1111	*Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines (Limit State Design)*
API Std 1163	*In-Line Inspection System Qualification Standard*
ASME B31.4	*Pipeline Transportation Systems for Liquids and Slurries*
ASME B31.8	*Gas Transmission and Distribution Piping Systems*
ASME B31.8S	*Managing System Integrity of Gas Pipelines*
ASME B31G	*Manual for Determining the Remaining Strength of Corroded Pipelines: Supplement to B31 Code for Pressure Piping*
ANSI/ASNT ILI-PQ	*In-Line Inspection Personnel Qualification and Certification'*
BS 7910	*Guide to methods for assessing the acceptability of flaws in metallic structures*
EN 13509	*Cathodic protection measurement techniques*
EI Technical Publications	*Guideline for Management of Integrity of Subsea Facilities*
EPRG publication	*EPRG Methods for assessing the tolerance and resistance of pipe to external damage*
NACE SP0102	*In-Line Inspection of Pipelines*
NACE 35100	*In-Line Nondestructive Inspection of Pipelines*
NACE TM0212-2012	*Detection, Testing, and Evaluation of Microbiologically Influenced Corrosion on Internal Surfaces of Pipelines*
PDAM	*9909A-RPT-001 The Pipeline Defect Assessment manual (PDAM) / PDAM Joint Industry Project*