

DIRECTORATE GENERAL OF HYDROCARBONS

Ministry of Petroleum & Natural Gas, Government of India

Tender No: DGH/ENQ/NDR/05/2026

Volume-I SCOPE OF WORK

**Re-Processing & Interpretation (P&I) of Legacy 2D & 3D Seismic Data
AND
3D Broadband Seismic Data Acquisition, Processing & Interpretation
(API)**

Bengal Basin | East Coast of India

Duration: 36 Calendar Months

1. PROJECT OVERVIEW

1.1 Introduction & Objective

The Directorate General of Hydrocarbons (DGH) invites proposals for Re-Processing and Interpretation (P&I) of legacy 2D and 3D marine seismic data of the Bengal Basin (Appendix-I) in India's East Coast. Subsequently, 3D Broadband seismic acquisition, processing & interpretation (API) shall be carried out under the Multi-Client (MC) model.

The quantum of legacy seismic data for re-processing & interpretation and 3D Broadband Seismic API:

Sl.No	Basin Name	Quantum for Re-Processing & Interpretation		Quantum for 3D Broadband Seismic API (SKM)
		2D (LKM)	3D (SKM)	
1	Bengal	43000	23000	Up to 10,000 (as approved by DGH)

The primary objectives of this programmes are:

- To add value to legacy seismic data through state of the art re-processing and interpretation techniques and to generate a single integrated value added seismic volume for the basin, enabling improved interpretation and prospect identification.
- Interpretation and identification of the play fairways, prospective areas and potential features or leads for internal use of DGH.
- Update the geological model using the integrated seismic volume as and when new data becomes available. Newly acquired 2D seismic data shall be incorporated at the interpretation stage to enhance and refine the subsurface understanding.
- To carry out 3D seismic API in identified prospect areas for delineation of hydrocarbon zone.
- For each 3D contract area, preparation of the Docket and supporting technical and promotional volume/package for marketing and bid promotion for DGH.

Scope of Work (SoW) of the project contains two parts:

Part A: Re-processing & Interpretation of legacy 2D and 3D Seismic Data

Part B: 3D Broadband seismic API under the Multi-Client (MC) model based on Re-Processing & Interpretation of legacy 2D and 3D seismic data

1.2 Project Duration

1. The total stipulated timeframe for execution of the legacy data Re-processing & Interpretation under Part-A and the subsequent 3D Broadband Seismic Acquisition, Processing and Interpretation (API) under Part-B shall be Thirty-Six (36) calendar months.

2. The work under Part-A, as specified in the Scope of Work (SoW), shall commence within Thirty (30) days from the date of issuance of the Letter of Intimation (LoI) /Letter of Award (LoA) or receipt from DGH of legacy data equivalent to Eighty Percent (80%) of the total data volume, whichever occurs later.
3. The duration for completion of Part-A shall be Twenty-Four (24) months from the commencement of services.
4. The Project Commencement Date shall be the date on which Part-A commences.
5. The overall Project Duration shall be Thirty-Six (36) calendar months from the Project Commencement Date.
6. Part-B may commence at any time during the Project Duration and shall be completed within the overall Project Duration of Thirty-Six (36) calendar months from the Project Commencement Date.

Part A: Re-processing & Interpretation of legacy 2D and 3D Seismic Data

2. GEOLOGY OF THE BASIN

2.1 Bengal-Purnea Basin

Bengal-Purnea is a Category III basin (largely undiscovered in-place), situated along the East Coast of the Indian Peninsula. It comprises three sub-basins: Bengal Onland, Bengal Offshore, and Purnea Onland.

2.1.1 Bengal Offshore

The basin hosts an exceptionally thick sedimentary succession exceeding ~10 km (Permo-Triassic to Recent), dominated by Tertiary deposition linked to the Ganga-Brahmaputra system. Key characteristics:

- Hydrocarbon plays range from Pliocene to Eocene; deepest Eocene play at ~6-8+ km depth.
- Significant Middle Miocene play (two-thirds of potential); channelised deposits in the east-central area offer major exploration targets.
- Biogenic gas shows reported across Paleogene to Miocene-Pliocene intervals.
- Established oil and gas discoveries in the Bengal Onland portion.

2.1.2 Purnea Sub-Basin

Plays are primarily within Gondwana sequences (Karharbari, Barakar, and Raniganj formations). Deepest Karharbari play at ~3-5 km depth; overall sediment thicknesses up to ~5 km.

3. LEGACY DATA AVAILABILITY

The raw field data and other ancillary datasets shall be made available by DGH to the service-provider after issue of LoA for re-processing & interpretation. To support the reprocessing and interpretation, available/shareable well data / GM data / associated reports will also be provided to Service-provider.

4. SEISMIC DATA RE-PROCESSING

- A single integrated seismic volume shall be generated through the re-processing of legacy 2D and 3D seismic data.
- The legacy data is pre-existing property of the Government of India and the right to market or sell any derivatives from the re-processing of legacy data shall lie exclusively with Government of India.
- In the process of generating the integrated seamless volume, all 2D and 3D data will be merged at the **Pre-Stack level** using a single reference coordinate grid system in consultation with DGH. Phase and amplitude of seismic data shall be made consistent throughout the single integrated volume by applying suitable techniques. The seismic lines shall be tied with the available 3D and 2D datasets to establish consistency and continuity between different seismic horizons of all seismic surveys.

4.1 2D and 3D Time Domain Re-Processing Workflow (Pre-STM)

The following generic workflow shall be finalised with DGH before commencement. All steps require standard QC outputs and approved by DGH

1. Input: SEG-D / SEG-Y data
2. Resampling of data at 2 ms (if required)
3. Pre-Stack Survey merge at appropriate level
4. Field geometry assignment: tidal static update in seismic header, seismic-navigation merge
5. Bad trace and shot editing
6. Low-cut frequency filtering
7. De-spiking; spurious spike / noise attenuation
8. Trace and shot interpolation
9. Tidal static application and gun & cable statics
10. Receiver motion correction
11. Amplitude recovery
12. Multi-pass swell noise attenuation (shot domain and other domains)
13. Direct arrival noise attenuation
14. Linear noise attenuation
15. Seismic interference attenuation (if applicable)
16. Other noise attenuation: ship noise, cable noise, debris noise
17. De-bubble
18. De-signature to zero-phase; receiver and source de-ghosting for broadband processing; datum to MSL
19. Water velocity correction
20. Shallow water demultiple (if required)
21. 2D / 3D Surface-Related Multiple Elimination (SRME)
22. Tau-P Deconvolution (If required)
23. Velocity analysis at 2 km / (2 km X 2 km) intervals; velocity field build-up to minimise misties
24. High-resolution Radon demultiple

25. Intra-bed demultiple and/or additional demultiple methods as required
26. Remnant noise and multiple attenuation
27. Inverse-Q compensation (phase only, data-derived)
28. Time-variant filter (if required)
29. Removal of applied amplitude recovery
30. Offset distribution for pre-migration gathers (including 5D regularisation / interpolation, noise attenuation, Voronoi scaler)
31. Isotropic Kirchhoff Pre-Stack Time Migration (PreSTM) with smooth demultiple velocity field
32. Migration velocity analysis at 1 km / (1 km X 1 km) interval; velocity field update to minimise mis-ties
33. Isotropic Kirchhoff PreSTM with updated velocity field
34. Anisotropic migration velocity analysis: Vp and interval Eta at 500 m / (500 m X 500 m) interval; velocity field build-up
35. Anisotropic Kirchhoff PreSTM (optimal dip and aperture)
36. Post-migration velocity analysis at 250 m / (250 m X 250 m) interval; velocity field build-up
37. Inverse-Q compensation (amplitude only, if required)
38. Post-migration demultiple / noise attenuation
39. High-density stacking velocity analysis
40. Additional gather flattening for AVO studies
41. Trim Statics , RMO
42. Final mute testing, stack, and partial angle stacks (Near , Mid, Far)
43. Final Raw stack
44. Post-stack noise attenuation (footprint removal)
45. Post-stack deconvolution (if required)
46. Low frequency enhancement
47. Time-variant filter, low-cut and high-cut filter, Dip filtering (if required)
48. Spectral balancing / amplitude recovery (if required)
49. Coherency enhancement (if required)
50. Polarity to SEG normal

4.2 Depth Domain Processing Workflow (Pre-SDM)

4.2.1 Initial Setup

1. Data input: pre-migration offset gathers, well data (if available), and PreSTM velocity field
2. Horizon picking: minimum 3 horizons interpreted on time-migrated stack for PSDM
3. Initial velocity model: derived from PreSTM velocities converted to interval velocities in depth, then spatially smoothed

4.2.2 Velocity Model Iteration (up to 5 iterations)

Iteration 1:

- Isotropic Kirchhoff Pre-Stack Depth Migration (PSDM)
- CMP gather preconditioning
- Tomographic velocity update at appropriate intervals as approved by DGH
- Test-line QC: gathers, stack, Gamma/Delta velocity

Iteration 2:

- Anisotropic parameter analysis (epsilon and delta); well calibration if available; horizon-guided anisotropic property distribution
- Anisotropic Kirchhoff PSDM (TTI)
- CMP gather preconditioning
- Tomographic velocity update at appropriate intervals as approved by DGH
- Test-line QC: gathers, stack, Gamma/Delta velocity

Iterations 3 to 5 (minimum 4; 5th if required): Repeat iteration 2 steps with QC after each.

4.2.3 Final PSDM Processing

1. **Full Waveform Inversion for velocity model building:** Band Frequency will be decided depending on input data S/N, complexity of near surface velocity. The FWI workflow shall include iterative velocity model updates, starting with low-frequency data to resolve large-scale structures, followed by high-frequency iterations for fine-scale details, constrained by available well data.
2. Final Anisotropic Kirchhoff PSDM (TTI) / Beam PSDM— optimal dip, aperture, depth step, and output depth
3. Production volume QC and mis-tie analysis (horizons and well markers if available)
4. Sort to CMP domain
5. Post-migration velocity analysis (high-density)
6. Inverse-Q compensation (amplitude only, if required)
7. Post-migration demultiple and noise attenuation
8. Raw stack
9. Gather flattening for AVO studies; partial angle stacks
10. Trim Statics , RMO
11. Final stack
12. Post-stack noise attenuation
13. Post-stack deconvolution (if required)
14. Time-variant filter; low-cut and high-cut filter (if required)
15. Spectral balancing / amplitude recovery
16. Low frequency enhancement
17. Coherency enhancement
18. Polarity to SEG normal

NOTE:

Amplitude relations (AVO characteristics) shall be preserved throughout all processing steps except post-stack scaling or image enhancement procedures. Close interaction with DGH QC personnel is required for finalization of PreSTM, PreSDM, and optional processing parameters.

4.3 Processing Key Personnel

Position	Minimum Experience	Minimum Headcount
Project Manager (Processing)	10 years, including ≥ 5 years as Project Manager (2D/3D Marine Seismic Processing)	2
Senior Processing Geophysicist	7 years, including ≥ 5 years as Senior Processing Geophysicist (Time and/or Depth, 2D/3D Marine)	4
Processing Geophysicist	5 years, including ≥ 3 years as Processing Geophysicist (2D/3D Marine, Time and/or Depth)	5

4.4 Infrastructure & General Processing Requirements

- SERVICE PROVIDER shall deploy all required hardware, software, tape drives, plotters, printers, and peripheral equipment.
- EBCDIC headers shall be provided for all processed data in standard prescribed formats.
- DGH representatives shall participate actively at key processing stages; simultaneous knowledge transfer to DGH is required.
- Monthly progress reports shall be submitted covering processing steps completed and percentage of total volume processed.
- All QC displays generated as standard procedure or specifically requested by DGH shall be produced and documented.
- Section displays scales: Horizontal 6 cm = 1 km (normal) or 6 cm = 2 km (reduced); Vertical 5.0 inch/sec or 2.5 inch/sec.

5. SEISMIC DATA INTERPRETATION

5.1 Interpretation Objectives

The legacy data is pre-existing property of the Government of India and the right to market or sell any derivatives from the interpretation of re-processed legacy data shall lie exclusively with Government of India.

The broad objective is to build a comprehensive tectonic, basin, and petroleum system model supporting hydrocarbon prospectivity assessment. Specific objectives include:

- Mapping key structural and stratigraphic horizons.
- Time-to-depth conversion using calibrated velocity models.
- Identification, analysis, and ranking of hydrocarbon leads and prospects.
- Update the geological model using the integrated seismic volume as and when new data becomes available. Newly acquired 2D seismic data shall be incorporated at the interpretation stage to enhance and refine the subsurface understanding.
- Recommendation of exploratory drilling locations and identification of prospect areas for 3D seismic broadband survey under Multi-Client model.

5.2 Data Integration

Before commencing interpretation, the SERVICE PROVIDER shall collect and integrate all relevant geoscientific data from DGH and publicly available sources, including but not limited to:

- Geological data and associated reports.
- Aerial photographs and satellite imagery.
- Gravity and magnetic data and associated reports.
- Existing and vintage seismic data from the area and nearby basins.
- Well logs, petrophysical data, pressure/production data, and well completion reports (where available).
- All available geoscientific reports pertaining to the area.

5.3 Interpretation Workflow

5.3.1 Well-to-Seismic Calibration

- Digital well log QC, display, and stratigraphic analysis.
- Synthetic seismogram computation using sonic, density, and check shot/VSP data.
- Seismic well-tie and horizon identification.

5.3.2 Structural & Fault Interpretation

- Mapping of minimum 5 correlatable horizons from basement to water bottom.
- Fault picking, correlation, and mapping; detailed fault pattern analysis.
- Fault-seal analysis; interpretation of deformational systems, stress/strain directions, and fault interplay.

5.3.3 Stratigraphic Analysis & Seismic Stratigraphy

- Sequence stratigraphy mapping.
- Recognition of seismic stratal patterns and stratal terminations (onlap, truncation, pinch-out etc.).

- Seismic facies analysis and depositional environment assessment using seismic attributes.

5.3.4 Map Generation

- Two-Way Time (TWT) contour maps on all interpreted horizons.
- Isochron computation, analysis, and isochron & isochronopach maps.
- Time-to-depth conversion and depth contour maps.
- Isopach maps.
- Velocity maps.
- Seismo-geological sections and fence diagrams.

5.3.5 Seismic Attribute Analysis

- AVO analysis: Intercept, Gradient, Fluid Factor attributes.
- P-impedance sections through seismic inversion.
- Amplitude extraction along key horizons and discrete stratigraphic intervals.
- Generation of other relevant attributes (coherence, variance, sweetness, spectral decomposition, etc.).

5.3.6 Prospect Generation & Ranking

- **Petroleum system modelling** incorporating global analogues where applicable.
- Structural and stratigraphic lead analysis: entrapment, reservoir extent.
- Prospect generation, risking, and ranking by overall geological merit.
- Identification and recommendation of exploratory drilling locations.
- Recommendation of future exploration strategy and development programme.

5.4 Interpretation Key Personnel

Position	Minimum Experience	Minimum Headcount
Project Manager (Interpretation)	10 years, including ≥ 5 years as Project Manager (2D/3D Seismic Interpretation)	2
Senior Interpretation Geophysicist and Geologist	7 years, including ≥ 5 years as Senior Interpretation Geophysicist/Geologist (2D/3D)	4
Interpretation Geophysicist and Geologist	5 years, including ≥ 3 years as Interpretation Geophysicist / Geologist (2D/3D)	5

6. QUALITY CONTROL

6.1 QC of Re-Processing

Quality control of data processing is the key responsibility of the SERVICE PROVIDER. A dedicated team of DGH will monitor the reprocessing & interpretation project. DGH requires that the final processed seismic data is free of all significant geophysical errors and is delivered on schedule. DGH representatives shall have timely access to workstations with real data access and screen-dump capability.

Mandatory QC products include but are not limited to:

- Shot record display for bad/noisy trace editing.
- Edited shot display: auto-editing/de-spiking results.
- S/N ratio and RMS amplitude display over zone of interest.
- Navigation merge verification: source-receiver distance, gun firing sequence, source-cable shape plot, first-break analysis, near-trace gather.
- Source signature plot before and after signature deconvolution.
- Amplitude and power spectrum before and after each process on gather and stack.
- Gather/stack RAP plots for geometrical spreading/exponential gain/offset-dependent gain.
- PSTM corrected gather displays at intermediate velocity analysis locations.
- Mute panel and TVF selection panel displays.
- Fold of coverage display

Parameter testing shall be conducted for:

- True amplitude recovery optimisation.
- Flex binning options.
- Pre-stack multiple/noise attenuation.
- Mute testing (front-end, top mute, inside trace mute).
- Post-stack random noise attenuation.
- Q compensation (amplitude and phase).
- Post-stack deconvolution and spectral balance.
- Migration tests: up to 5 velocity percentages, dip, aperture, impulse response
- Filter and scaling tests.
- Residual Amplitude Compensation (RAC) with space-varying option if required.
- Requisite parameter testing displays for all steps mentioned in re-processing workflow

6.2 QC of Data Interpretation

Interpretation shall follow a structured workflow to minimise uncertainty. Key QC stages:

- Data Compilation & Quality Assessment: Evaluate seismic resolution, signal quality, phase consistency, navigation accuracy, and processing reliability before commencing interpretation.
- Regional Geological Understanding: Establish basin tectonics, depositional history, stratigraphy, and petroleum system elements as interpretation context.
- Well-to-Seismic Calibration: Use sonic, density, check shot, and VSP data; generate synthetic seismograms; tie geological markers to seismic reflections.
- Horizon & Fault QC: Ensure consistent identification across all seismic lines; validate structural closures and fault geometries.

- Attribute QC: Validate seismic attributes against geological expectations; cross-check with well data where available.
- Velocity & Depth Conversion QC: Validate calibrated velocity models against well-marker depths.
- Uncertainty & Risk Assessment: Continuously evaluate uncertainties in velocity assumptions, structural interpretation, and geological models.
- Integration QC: Cross-validate interpretation with petrophysical, geochemical, gravity, magnetic, and geological datasets.
- Documentation: Maintain detailed records of interpretation workflows, assumptions, mapping decisions, and final outputs.

7. DELIVERABLES (Re-Processing & Interpretation)

All deliverables shall be provided in the quantities and formats specified. Any deliverable not explicitly listed but deemed necessary for completeness shall be supplied at no additional cost to DGH. The SERVICE PROVIDER shall **mandatorily upload** all processed and interpreted data to the National Data Repository (NDR) Cloud. The processed and interpreted data are to be uploaded post processing/ interpretation, validation and quality checks.

All data submissions shall be made in duplicate. The first copy shall be uploaded to the NDR Cloud, and the second copy shall be submitted through physical storage media such as Cartridge, Hard Disk, or any other approved hardware medium.

7.1 Re-Processing Deliverables

Medium: 1 copy on LTO-07/08 + 1 copy on SSD. Reports: 2 hard copies + 2 digital copies on SSD. Others: as required by DGH.

7.1.1 PreSTM Outputs

#	Item	Format
1	Geometry-merged shot gathers	SEG-Y
2	Final pre-migrated CMP gathers (input to PSTM)	SEG-Y
3	Raw PreSTM gathers (no mute, with NMO)	SEG-Y
4	Raw PreSTM gathers (no mute, without NMO)	SEG-Y
5	PreSTM gathers after gather conditioning (mute + NMO applied)	SEG-Y
6	Final pre-migrated stack section	SEG-Y
7	Raw PreSTM stack (no conditioning)	SEG-Y
8	Final PreSTM stack (with and without scaling)	SEG-Y
9	Final PreSTM partial angle stacks (selected angles)	SEG-Y
10	Final migration RMS velocity fields for PSTM (with and without smoothing)	SEG-Y
11	Final stacking velocity fields (after high-density picking)	SEG-Y
12	Final Eta model	SEG-Y
13	Single integrated merged volume basin wise (Raw & Final)	SEG-Y

#	Item	Format
14	Single integrated merged velocity basin wise (Migration & Final Stacking Velocity)	SEG-Y & ASCII

7.1.2 PreSDM Outputs

#	Item	Format
1	Final pre-migrated CMP gathers (input to PSDM)	SEG-Y
2	Raw depth-migrated gathers in depth and stretched to time	SEG-Y
3	Final depth-migrated gathers after gather conditioning (depth domain)	SEG-Y
4	Final depth-migrated gathers after gather conditioning (stretched to time)	SEG-Y
5	Raw depth-migrated stack	SEG-Y
6	Unscaled depth-migrated stack	SEG-Y
7	Scaled depth-migrated stack	SEG-Y
8	Unscaled depth-migrated stack converted to time domain	SEG-Y
9	Scaled depth-migrated stack stretched to time	SEG-Y
10	Final PreSDM partial angle stacks (selected angles, stretched to time)	SEG-Y
11	Final interval velocity model (depth domain smooth and unsmooth)	SEG-Y
12	Final anisotropic parameters (Epsilon, Delta, and Eta model)	SEG-Y
13	Single integrated merged volume basin wise (Raw & Final)	SEG-Y
14	Single integrated merged velocity basin wise (Migration & Final Stacking Velocity)	SEG-Y & ASCII

7.1.3 Ancillary Re-Processing Data

#	Item	Format/Media
1	Final P1/90 or IOGP P1/11 file used for geometry assignment	ASCII / SSD
2	Trace editing tables	ASCII / SSD
3	Tidal table/static	ASCII / SSD
4	Final mute file	ASCII / SSD
5	Final migration velocity field for PSTM (with and without smoothing)	ASCII / SSD
6	Final stacking velocity field (high-density picking)	ASCII / SSD
7	SEG-Y wire frames for all deliverables	ASCII / SSD
8	Subsurface coverage/fold maps (1:25,000 and 1:50,000)	CGM & PDF / SSD
9	Picked horizons on time-migrated sections	ASCII / SSD

#	Item	Format/Media
10	Water bottom map for each profile	ASCII / SSD
11	Final processing report and presentation (6 copies on SSD + hard copies)	PDF / SSD
12	Base map (scales 1:50,000 / 1:100,000 / 1:250,000)	PDF/CGM / SSD
13	Final structural parameters (Dip and Azimuth model)	SEG-Y / SSD

7.1.4 SEG-Y Tape/Media Header Requirements

All SEG-Y deliverable media headers shall include:

- Complete projection system description: spheroid name, central meridian.
- Total and live line/trace counts.
- Group interval and source interval.
- Summary of processing sequence.
- Polarity of processed data.
- Data in SEG-Y IBM 32-bit floating-point format with line number, trace number, CDP, X, Y in respective header words.
- No embedded EOFs; structure: 3200-byte EBCDIC header, 400-byte binary header, data traces in sequence, EOT.
- All deliverables properly labelled and annotated.

7.2 Interpretation Deliverables

Delivered as: 2 hard copies + 2 sets of soft copies on SSD or Drop Site of NDR on agreed frequency with DGH.

7.2.1 Hard Copy Outputs

- Comprehensive final interpretation report.
- All time structure maps and depth structure maps at 1:50,000 and 1:100,000.
- Seismo-geological sections, fence diagrams and correlations.
- Interpreted seismic sections.
- Fault pattern maps.
- Geoscientific data correlation maps.
- Velocity maps.
- Isopach and isochronopach maps.
- Attribute sections and maps.
- AVO and inversion study results.
- Prospect map and any other relevant maps.

7.2.2 Soft Copy Outputs (SSD and LTO-7/8)

- 3 sets of full interpreted data in ASCII format.
- 3 sets of full interpreted data in compatible SEG-Y format.
- All attribute profiles in SEG-Y format.
- Interpretation project back-up at key QC stages (mutually agreed formats).
- Final interpretation project back-up with all relevant data in SEG-Y format.
- Complete interpretation data and final project in Petrel-compatible format.

NOTE: The final interpretation report must be comprehensive and self-contained, including QC measures, methodologies, workflow sequences with parameters, and inferences from all deliverables.

8. REPORTING & DATA MANAGEMENT

8.1 Tape/Media Labels

Each cartridge/media shall be labelled with:

- SERVICE PROVIDER and DGH logos; vessel name; area/survey name.
- Type of data acquisition; full line number (including prefixes and suffixes).
- First and last shot point and file numbers; data format; recording date.
- Cartridge number; sampling interval; record length.

8.2 Data Shipment Procedures

- First copy of all data tapes shall be shipped to DGH's designated processing centre or archive at the earliest opportunity (or as requested by DGH).
- Second copy shipped once the first copy has been confirmed as successfully read.
- SERVICE PROVIDER is responsible for data safeguarding until second copy is delivered.
- Cartridges containing only rejected lines/segments shall be marked 'DNP' (Do Not Process) and included in all shipments; DNP tapes shall be copied if they contain data.
- Electronic and paper copies of media transmittal forms, verified by DGH representative, shall accompany all shipments.
- An electronic transmittal copy (tabulated, one row per tape, highlighting DNP tapes) shall be emailed to DGH simultaneously with shipment.

Part B: 3D Broadband seismic API Based on Re-processing & Interpretation under Multi-Client Model

1. Objective

Following are the objectives of 3D broadband seismic API

- 3D Broadband marine seismic data will be acquired in the identified prospect as approved by DGH through the re-processing of legacy seismic data as indicated in the SoW of Part-A.
- Quantum of 3D seismic data shall be upto 10,000 SKM as approved by DGH. The data is to be acquired under multi-client mode in maximum four (4) parts.
- The Service Provider will have exclusive rights to license 3D Seismic API data under multi-client model for a period of **Six (6) years** from the date of commencement of seismic data acquisition.

2. Survey Summary

Parameter	Details
Survey Area	Bengal Basin, East Coast, India
Survey Type	3D Broadband Seismic
Total Volume	Up to 10000 SKM (full fold)
Minimum Vessels Required	1 (One)
Water Depth Range	50 – 4,000 m
Coordinate Reference System	WGS-84 / UTM Zone 45N

3. SURVEY AREA & OPERATIONAL LOGISTICS

3.1 Field Season & Weather

The monsoon period is generally June to September (may vary; consult the Indian Meteorological Department). The fair-weather operational window (Field Season) runs approximately October to May (~8 months).

3.2 Environmental & Operational Conditions

Factor	Description & SERVICE PROVIDER Obligations
Bathymetry / Currents / Tides	SERVICE PROVIDER must familiarise themselves with all metocean conditions in the survey area prior to commencement.
Offshore Installations	Survey area is apparently free of installations; however, E&P activities cannot be ruled out. Confirm before operations.
Fishing Activity	Significant fishing activity is expected. SERVICE PROVIDER is solely responsible for coordination with local fishing communities, deployment of adequate chase vessels (per DG Shipping guidelines), and ensuring no interference with fishing operations.

4. 3D SEISMIC DATA ACQUISITION

4.1 Scope of Acquisition Work

The SERVICE PROVIDER shall execute all the following during the acquisition phase:

- 3D Broadband Seismic Data Acquisition per the specifications in Section 4.3.
- Simultaneous Bathymetric Data Acquisition along all seismic lines.
- Recording of Navigation and Positioning data unambiguously tied to seismic and bathymetric data.
- On-board QC Processing
- Regular data delivery to DGH as data become available.

4.2 Survey Vessel Requirements

The SERVICE PROVIDER must furnish details of the survey vessel **within sixty (60)** days from the date of approval of the seismic data acquisition area by DGH or before the commencement of seismic data acquisition whichever is earlier. The SERVICE PROVIDER shall offer minimum one or more fully equipped survey vessels capable of 3D Broadband Seismic acquisition in streamer mode, with on-board seismic processing and QC operations. The vessel must be capable of simultaneously conducting seismic and bathymetric acquisition.

- Maximum vessel age: less than 24 years at the time of execution of work.
- The number of short-listed vessels will be communicated to technically acceptable bidders before price bid opening.
- SERVICE PROVIDER must deploy vessel(s) from the short-listed set only.

NOTE: The SERVICE PROVIDER shall clearly indicate the vessel(s) offered. DGH reserves the right to approve or reject any vessel.

4.2A Older Vessel Compliance & Noise Mitigation Requirements

Where the survey vessel offered is 15 years of age or older (up to 24 years) during the entire period of contract execution, the SERVICE PROVIDER shall demonstrate that data quality will be maintained to the same standards as for a newer vessel. The requirements below are mandatory for such vessels and shall apply cumulatively. DGH reserves the right to require independent third-party verification of any of these conditions and/or to reject the vessel which in the opinion of DGH, is not found suitable for performance of the Services under the Contract.

4.2A.1 Pre-Mobilisation Vessel Noise Audit

Before vessel acceptance and prior to mobilisation to the survey area, the SERVICE PROVIDER shall conduct and submit to DGH a comprehensive vessel noise audit carried out by a qualified independent marine geophysical noise specialist. The audit shall cover:

- Full spectral noise characterisation (1–500 Hz) of all on-board mechanical and electrical noise sources under representative operational conditions (engines at shooting RPM, compressors running, and streamer deployed).
- Radiated noise measurement at the streamer tow point using a calibrated hydrophone array or equivalent method, with results compared against the ambient cable noise limits in Section 4.9.
- Identification of all noise sources contributing above 3 μ bar RMS at the near-offset streamer group, including but not limited to: main propulsion engines, thrusters, generators, air compressors, hydraulic systems, winches, and HVAC systems.

- A written noise mitigation plan (NMP) endorsed by the SERVICE PROVIDER's Chief Geophysicist, detailing the specific engineering and operational measures to be applied for each identified noise source before and during the survey.
- The noise audit report and NMP shall be submitted to DGH for review and approval at least 30 days prior to mobilisation. Survey operations shall not commence until DGH formally accepts the audit and NMP.

4.2A.2 Propulsion & Machinery Isolation Standards

Vessels having 15 years of age or older (up to 24 years) during the entire period of contract execution typically exhibit higher structure-borne and waterborne noise due to wear and age-related degradation of vibration isolation. The SERVICE PROVIDER shall ensure the following are in place and verified prior to departure:

System	Required Standard for Vessels
Main Engine Mounts	Anti-vibration mounts inspected and replaced/reconditioned if dynamic stiffness exceeds OEM specification. Certificate of compliance required from a certified marine engineer.
Shaft & Propeller	Propeller shaft dynamic balance verified; propeller blades inspected for cavitation pitting and erosion damage. Blades to be re-pitched or replaced if tip erosion depth exceeds 2 mm. Stern tube bearing clearance within OEM tolerance.
Air Compressors	Compressors supplying the gun array to be mounted on verified anti-vibration isolators. Discharge piping to include flexible sections to prevent structure-borne transmission. Compressor noise characterised during pre-mob noise audit.
Generators & Switchboard	All generators to be on anti-vibration mounts. 50/60 Hz electrical interference noise verified absent from streamer channels during the pre-mob noise test; elimination must not rely on the seismic recording unit notch filter.
Hydraulic Systems	Hydraulic pump mounts and pipework to include vibration-damping fittings. All hydraulic operations (winch, bird deployment) to be suspended during active seismic recording unless proven to contribute < 1 μ bar RMS at the nearest streamer group.
Thruster Systems (if fitted)	Side thrusters and dynamic positioning thrusters to be locked off or declutched during seismic recording. Any mandatory use to be authorised by DGH QC representative and noise contribution documented in Observer's Log.

4.2A.3 Tow Configuration Adaptations for Older Vessels

Engine noise transmitted through the vessel hull and water column attenuates with tow distance. For vessels 15 years of age or older (up to 24 years) during the entire period of contract execution, the following tow configuration requirements apply:

- Near-offset streamer noise (groups within 300 m of the vessel) shall be verified during the pre-mob noise test to be $\leq 14 \mu$ bar RMS. If this cannot be achieved, the lead-in cable length shall be increased to a minimum of 200 m (or the minimum necessary to achieve compliance), subject to DGH approval.
- A dedicated inline notch (mechanical vibration damper / stretch section) shall be fitted between the lead-in cable and the active streamer section if structure-borne noise transmitted through the tow cable exceeds 5 μ bar RMS at the first active group.

- Tow speed shall be limited to the minimum operationally acceptable speed consistent with maintaining streamer depth and course stability. Any increase beyond the nominal tow speed shall require documented DGH QC representative approval and noise re-verification.
- Where vessel noise causes the first 1–3 active groups to exceed the noise limit of Section 4.9, those groups shall be flagged as potentially degraded in the Observer's Log. The SERVICE PROVIDER shall compensate by ensuring the remaining active spread meets or exceeds the fold and offset requirements without those groups if agreed with DGH.

4.2A.4 Enhanced On-board Noise Monitoring for Older Vessels

In addition to standard QC requirements in Section 4.9, vessels of 15 years or older (up to 24 years) during the entire period of contract execution shall implement the following enhanced real-time noise monitoring:

Monitoring Requirement	Frequency / Trigger
Full spectral noise scan (1–500 Hz) on a dedicated monitor channel (near-offset group)	Every 2 hours during production shooting; immediately after any machinery start-up, speed change, or maintenance event
Propeller RPM and engine load logged against ambient noise level	Continuously, logged in Observer's Log at every 40 shot-point interval
Cable noise test record (cartridge and monitor record)	Before and after each line; also triggered whenever spectral scan shows any frequency band exceeding 60% limit as mentioned in the Section 4.9
Ship-noise characterisation shot (no airgun, streamer recording only)	Once per day during production, and at any time noise source cannot be identified. Results provided to DGH representative.
Shooting speed optimisation test (vary RPM vs noise measurement)	At commencement of survey and after any propulsion system maintenance; results documented and approved by DGH

4.2A.5 Noise Limits — Older Vessel Compliance Thresholds

The standard noise limits in Section 4.9 remain fully applicable to all vessels regardless of age. For vessels 15 years of age or older (up to 24 years) during the entire period of contract execution, the following additional threshold conditions apply:

- If ambient cable noise on more than 3 consecutive groups (excluding the first 3 near-offset groups and tail groups) exceeds 10 μ bar RMS on any line, the line shall be paused immediately. Operations shall not resume until the source of elevated noise is identified, mitigated, and noise re-verified at or below 7 μ bar RMS.
- If vessel-generated coherent noise (ship noise arriving from ahead of the streamer) is observed above 6 μ bar RMS during production shooting on any two consecutive lines, the SERVICE PROVIDER shall implement immediate operational noise reduction (e.g. speed reduction, machinery isolation) and notify DGH. Continued operations require DGH QC representative authorisation. If noise cannot be reduced below 10 μ bar RMS within 4 hours, the vessel shall be deemed temporarily non-compliant and operations suspended pending DGH review.
- During any noise event requiring a line stop under the above conditions, the failed segment shall be marked in the Observer's Log and shall not count toward chargeable SKM until DGH confirms the data meets noise specifications after on-board QC processing review.

4.2A.6 Vibration & Hull Condition Monitoring During Survey

To provide ongoing assurance of vessel seismic compatibility throughout the 12-month survey:

- A permanently installed accelerometer (or equivalent vibration sensor) shall be mounted on the lead-in tow-point / stern roller and on the main engine foundation. Data shall be logged continuously and made available to DGH on-board representative on demand.
- Any vibration level exceeding 150% of the pre-mobilisation baseline (as established during the noise audit) at the tow point shall trigger an immediate noise QC check and be documented in the daily operations report.
- Hull inspections relevant to seismic noise (stern tube, propeller shaft, propeller condition) shall be conducted at minimum at every scheduled dry-dock or annual survey, and inspection reports submitted to DGH within 7 days of completion.
- Any unplanned maintenance or repair event affecting the propulsion, generator, or compressor systems shall be followed by a noise re-verification test before seismic acquisition resumes. Results shall be submitted to DGH representative for approval.

4.2A.7 Data Quality Equivalence Certification Gate

A vessel of 15 years or older (up to 24 years) during the entire period of contract execution shall not be formally accepted for production seismic acquisition until it passes a Data Quality Equivalence (DQE) Certification Gate, defined as follows:

DQE Gate Criterion	Pass Condition
Ambient cable noise (full spread, excluding first 3 and last 3 groups)	$\leq 7 \mu\text{bar RMS}$ on $\geq 95\%$ of active groups during a 30-minute noise recording at operational tow speed and depth
Near-offset group noise (groups 4 to 10)	$\leq 14 \mu\text{bar RMS}$ on all groups
Spectral cleanliness — electrical interference bands	No coherent energy above $2 \mu\text{bar RMS}$ at 50 Hz, 60 Hz, or harmonics thereof on any active channel
Ship-noise coherent energy (from ahead)	$< 6 \mu\text{bar RMS}$ at slope 0–150 ms/km across full active spread
Brute-stack data quality check (100 SKM test acquisition)	Brute stack reviewed and approved by DGH geoscientist; signal-to-noise ratio, event continuity, and frequency content judged equivalent to a reference modern vessel dataset from a comparable geological setting
Observer's Log noise incidents (during test acquisition)	Fewer than 3 noise-related line stops per 100 SKM of test production

The DQE gate shall be conducted in the survey area (or an approved representative area) at the commencement of survey operations. DGH may waive individual criteria based on documented operational justification, but no waiver shall compromise the brute-stack data quality criterion. Failure to pass the DQE gate shall require the SERVICE PROVIDER to implement additional engineering noise mitigation measures at their own cost before re-testing.

4.2A.8 Reporting & Accountability

- All noise-related events, mitigation actions, compliance verifications, and test results shall be recorded in the Observer's Log and included in the daily operations report submitted to DGH.

- A monthly Vessel Noise Compliance Summary shall be submitted to DGH, covering noise incident count, noise-related downtime, any spectral anomalies observed, and confirmation that all vibration baselines remain within tolerance.
- DGH reserves the right to commission an independent noise audit of the vessel at any point during the survey, at the SERVICE PROVIDER's cost, if noise-related data quality concerns are raised by DGH's QC team.
- Any data acquired during a period in which the vessel was subsequently found to be operating outside the noise specifications of this section shall be subject to DGH review. DGH may reject such data or require reacquisition at no additional cost to DGH.

4.3 Seismic Survey Parameters

The following acquisition specifications shall apply; however, the SERVICE PROVIDER shall carry out survey design and evaluation studies to validate and/or fine-tune acquisition parameters, and submit results with a detailed Project Report to DGH for approval prior to vessel mobilisation.

#	Parameter	Specification
1	Streamer Type	Digital, 24-bit digitisation (Solid / Gel)
2	Number of Streamers	Minimum 8 Streamers
3	Streamer Length	Minimum 10,000 m
4	Group Interval	12.5 m
5	Streamer / Slant Depth	To be finalised based on approved survey design to achieve geological objectives
6	Nominal Near Offset	150 m
7	Cable Feathering Tolerance	± 10 degrees
8	Depth Controllers	At intervals ≤ 400 m
9	Depth Transducers (Calibrated)	At intervals ≤ 400 m
10	Cable Compasses	At intervals ≤ 400 m
11	Tail Buoy	Fitted with RGPS
12	Source Type Configuration	Dual Source and Optimised air-gun array (configuration finalised per approved survey design)
13	Sub-array Gun Count	≥ 3 (conventional source) ≥ 1 (dedicated low-frequency rich source)
14	Gun Depth	Optimised per approved survey design
15	Total Gun Volume	Minimum 6,000 in ³
16	Operating Pressure	Minimum 2,000 psi
17	Source Strength (P-P)	>100 bar-m (standard) >40 bar-m (low-frequency source) [filter: 128 Hz / 72 dB/octave out]
18	Source P/B Ratio	> 10:1
19	Frequency Spectrum	> 195 dB re 1 µPa @ 1 m at 4 Hz (standard) > 200 dB re 1 µPa @ 1 m at 4 Hz (low-frequency source) Average spectral value > 200 dB re 1 µPa @ 1 m from 10–70 Hz for any source
20	Source Interval	Flip Flop 25m

#	Parameter	Specification
21	Bin Size	6.25 m X 25 m
22	Nominal Fold	100
23	Record Length	16 seconds
24	Sampling Interval	2 ms
25	Recording Format	SEG-D de-multiplexed
26	Recording Media	LTO-7 / LTO-8 and SSD (new cartridges only)
27	Polarity	SEG standard (compression = negative; downward monitor displacement)
28	Raw Navigation Data	UKOOA P2/94 or IOGP P2/11 (ASCII)
29	Post-Processed Navigation Data	UKOOA P1/90 or IOGP P1/11 (ASCII)

4.4 Energy Source (Air-Gun Array)

The air-gun source array shall meet the specifications above and the following operational requirements:

- A state-of-the-art computer-controlled source synchronisation system shall be used, with graphical display and printout for continuous monitoring of individual gun performance.
- Printout summary of offset, delay, and error values (in ms) for all guns at intervals not exceeding 40 shot points.
- Prior to daily operations, the array shall be charged to working pressure; each pressure gauge monitored over 10 minutes. Any circuit showing >10% pressure loss shall be rectified before operations begin.
- Gun depth, volume, and operating pressure shall be recorded in the Observer's Log at line start, end, and at ≤40 shot-point intervals. All deviations shall be logged.
- In areas of known cetacean activity, a phased (soft) start-up shall be implemented progressively prior to the start of each line, in accordance with applicable environmental regulations and industry best practice (IAGC/IMO guidelines).

4.5 Seismic Streamer

The SERVICE PROVIDER shall deploy industry-standard digital streamers with the following requirements:

- 24-bit digitisation; solid or gel-filled construction.
- All sensors and electronics maintained in sound condition with adequate backup.
- Depth controllers and calibrated depth transducers at intervals ≤ 400 m.
- Cable compasses at intervals ≤ 400 m; integrated compass data used for accurate receiver group positioning.
- Tail buoy equipped with RGPS.
- Streamer shall be optimally ballasted for neutral buoyancy and verified prior to survey commencement.
- Receiver locations continuously monitored using state-of-the-art compasses.
- Operating depth/slant depth to be specified in the Project Report and recorded at ≤ 40 shot-point intervals.

4.6 Recording Instruments & Data Format

Item	Specification
Recording Format	SEG-D de-multiplexed; no deviation from SEG recommendations
Recording Media	LTO-7 / LTO-8 and SSD (new cartridges only)
Raw Navigation Data	UKOOA P2/94 or IOGP P2/11 (ASCII)
Post-Processed Navigation Data	UKOOA P1/90 or IOGP P1/11 (ASCII)
Fathometer Output	ASCII; corrected for draft, velocity, and tides
Bathymetry Sensor	Precision dual-frequency echo sounder with hull-mounted transducer

4.7 Navigation & Positioning System

4.7.1 DGPS System

A Primary and Secondary DGPS-based positioning system shall be deployed and maintained throughout the survey, with full source and streamer positioning capability. The two systems shall be as independent as possible, including the source of differential corrections. Relative GPS (RGPS) systems shall establish source and streamer positions.

- Positional accuracy: ± 5 m using standard single-frequency C/A code.
- Update rate: ≤ 4 seconds; latency: ≤ 10 seconds.
- Hardware/software phase-smoothed code via Carrier Aided Smoothing (CAS) or Integrated Doppler Smoothing (IDS).
- All data logged in WGS-84; time-tagged to GPS time.
- Reference/monitor coordinates accurate to ≤ 1.0 m laterally and ≤ 1.0 m vertically (WGS-84).
- QC computation: satellites with elevation $> 10^\circ$ and PDOP ≤ 4 only.
- All ionospheric/tropospheric corrections fully documented.
- Downtime from DGPS failure, differential signal loss, or non-space-segment issues is not chargeable to DGH.

4.7.2 Gyro Compass & Heading Sensor

- All streamer compasses shall be verified using an online verification method (e.g. DGPS baseline or GPS attitude determination system) from recent surveys, accepted by DGH prior to survey commencement.
- Compasses with dynamic bias $> 0.5^\circ$ shall be removed and recalibrated before use.
- Gyro compass shall be verified online using a suitable system; work shall not commence or continue on any line if the heading system is non-operational.

4.7.3 Navigation Data Processing & QC

- Navigation data processing shall be carried out in one integral network adjustment using all available data simultaneously, with full statistical analysis including outlier detection and reliability measures.
- Recorded positions required for every shot point; all data identified by date, time, line number, and shot point number.
- Continuous correlation between navigation, seismic shot point, and file numbers maintained; all mismatches recorded and reconciled.

- All positioning equipment calibrated to accepted industry standards prior to survey; DGH notified of any equipment modification/replacement after commencement.
- Provisional/final positioning data and daily logs provided to DGH on-board representative daily.

4.7.4 Survey Coordinate System

Parameter	Specification
Geodetic Datum	WGS-84
Reference Point	Geometric centre of source array
Projection System	Universal Transverse Mercator (UTM)
UTM Zone	45N

4.7.5 Pre-Survey Positioning Strategy Report

Prior to mobilisation, the SERVICE PROVIDER shall submit a documented Positioning Strategy to DGH covering equipment specifications, calibration and QC procedures, spare equipment inventory, redundancy levels, acceptance criteria, and network reliability assessment methods. Following mobilisation, the report shall be updated to include actual equipment deployed, serial numbers, offset diagrams, and calibration results.

Pre-plot maps and listings shall be prepared and submitted to DGH for review and approval before survey operations commence.

4.8 Pre-Survey Equipment Checks & Work Standards

The following shall be completed and verified before commencement of any data acquisition:

- DGPS positioning health check and gyro (or equivalent heading sensor) calibration, carried out at an Indian port or via third-party report accepted by DGH.
- All recording instruments verified against manufacturer specifications.
- Noise and polarity tests conducted before start of each line.
- Streamer ballasted for neutral buoyancy and verified at normal shooting speed.
- Bird (depth controller) operation checked on deck before deployment; birds displaced as far as possible from hydrophone sections.
- Propeller pitch/RPM tests conducted to minimise ship-induced noise.
- All equipment tests performed, deficiencies corrected, and results provided to DGH representative.
- Streamer continuity and leakage tests before start of each line.

4.9 Noise Standards

Noise Type	Specification
Ambient Cable Noise (12.5 m group, nominal depth)	$\leq 7 \mu\text{bar RMS}$
Groups < 250 m from vessel; 3 groups nearest tail buoy	$\leq 14 \mu\text{bar RMS}$
Groups adjacent to depth controllers	$\leq 14 \mu\text{bar RMS}$
Shallow water (streamer at shallower depth)	$\leq 20 \mu\text{bar RMS}$

Noise Type	Specification
Swell noise tolerance	$\leq 25 \mu\text{bar}$ on $\leq 5\%$ of traces per shot sequence; effects evaluated via onboard QC

Coherent noise limits (noise from ahead/astern):

Slope	Max Noise (12.5 m group, μbar RMS)
$> 300 \text{ ms/km}$	$28 \mu\text{bar}$
$150\text{--}300 \text{ ms/km}$	$14 \mu\text{bar}$
$0\text{--}150 \text{ ms/km}$	$6 \mu\text{bar}$

Constant coherent interference up to $10 \mu\text{bar}$ may be acceptable up to a maximum duration of 4 seconds. Coherent noise sources shall be identified, logged, and mitigated. Shot-to-shot timing differentials of noise shall exceed 500 ms.

4.10 Acquisition Procedures

4.10.1 Line Procedures

- Run-in distance: sufficient to eliminate residual noise/turn effects and allow gyro compass to settle. Minimum run-in = tow length (unless constrained by physical obstacles).
- Run-out distance: $\geq \frac{1}{2}$ active streamer length + $\frac{1}{2}$ source-to-near-trace offset, to achieve full fold coverage at line ends.
- Guns shall be fired and warmed up/tuned prior to start of each line.
- Cetacean soft start implemented on run-in to all lines in areas of cetacean concern.
- Each line shall be recorded in one pass wherever possible.
- Any line terminated within one streamer length of its start point shall be re-acquired in its entirety (except infill lines).
- Re-shoots shall be recorded in the same direction as the original line.
- Vessel track shall remain within $\pm 10 \text{ m}$ of the pre-plotted line. DGH QC representative may authorise deviations to avoid obstructions.

4.10.2 Maximum Sail Line Segments Permitted

Line Length	Maximum Segments
$< 20 \text{ km}$	2
$20\text{--}35 \text{ km}$	3
$35\text{--}50 \text{ km}$	4
$> 50 \text{ km}$	By agreement with DGH QC representative

4.11 Key Acquisition Personnel — Minimum Requirements

Position	Minimum Experience
Party Chief / Party Manager	10 years offshore seismic, including ≥ 5 years as Party Chief/Manager
Project Manager / Co-ordinator	10 years offshore seismic, including ≥ 5 years as Project Manager/Co-ordinator (stationed at Noida, UP or DGH-designated location)

Position	Minimum Experience
Chief Observer	10 years offshore seismic, including ≥ 5 years as Observer (offshore)
Chief Geophysicist / Seismologist	10 years offshore seismic, including ≥ 5 years as Seismologist (offshore)
Navigation Manager	10 years offshore seismic, including ≥ 5 years as Navigation Manager
HSE Manager	5 years offshore seismic, including ≥ 3 years as HSE Manager
Marine Operations Manager	10 years offshore seismic, including ≥ 5 years as Marine Operations Manager

NOTE: DGH shall have full authority to approve or reject any expert proposed for deployment. Prior DGH approval is required for all key personnel.

4.12 On-board QC Processing Sequence

The following on-board QC processing sequence shall be applied continuously during data acquisition:

1. Input: SEG-D field seismic data + P1/90 or IOGP P1/11 navigation data
2. Field trace / shot edits
3. Navigation merge
4. Source de-signature and de-bubble (zero-phase operator)
5. Removal of recording delay (if any)
6. Gain recovery
7. Tidal and gun & cable static application
8. Filters: low-cut and high-cut, or time-variant
9. Noise attenuation: swell noise, random noise, linear noise, direct arrivals, dispersive noise
10. De-Ghosting and Datuming- output in SEG Y
11. Velocity Analysis – every 1 km one CMP line of each sail line
12. Brute stack (one per Sail line)
13. Near Trace Cube (2-4 fold) generation

Following QC plots (not limited to) should be delivered to DGH Representatives for acceptance of Nav-merged data:

- Navigation Merged Gather (every 40th shot)
- Noise Records (Start and End of line)
- Channel RMS Noise (Start and End of line)
- RMS map for Water Bottom, Signal and Deep time window
- Near Trace Gather
- Linear Move Out plot
- Shot-Shot correlation
- Depth Edit map
- Brute Stack –one CMP line for each sail line
- Fold of coverage (Full Fold , Near , Near Mid , Mid Far and Far)

4.12.1 De-ghosting QC Standards

- FX plots (dB scale) generated for one inner and one outer cable per sail line, before and after receiver de-ghosting; cable depth also plotted.

- After de-ghosting: frequency notch minimised with at least 8 dB improvement in amplitude spectra in the zone of interest.
- Auto-correlation function after de-ghosting: side-lobe amplitude reduction $\geq 70\%$ relative to main peak.
- Frequency spectra generated before and after de-ghosting at regular intervals, confirming notch removal corresponding to cable depth.

5. 3D BROADBAND SEISMIC DATA PROCESSING

Seismic data processing shall be performed to achieve superior subsurface imaging for:

- Tectonic framework, basement configuration, and sedimentary package delineation.
- Structural, stratigraphic, and strati-structural play definition.
- Reservoir distribution and internal seismic sequence characterisation.
- Preserved/true amplitude output suitable for AVO and inversion studies.
- To generate best quality subsurface image for interpretation

The SERVICE PROVIDER shall deploy an expert team of geoscientists and perform comprehensive parameter testing prior to production processing. All final parameters shall be approved by DGH representatives. Processing costs shall include all experimental testing.

5.1 3D Time Domain Processing Workflow (Pre-STM)

The following generic workflow shall be finalised with DGH before commencement. All steps require standard QC outputs.

1. Input: SEG-D / SEG-Y data
2. Field geometry assignment: tidal static update in seismic header, seismic-navigation merge
3. Bad trace and shot editing
4. Low-cut frequency filtering
5. De-spiking; spurious spike / noise attenuation
6. Trace and shot interpolation
7. Tidal static application and gun & cable statics
8. Receiver motion correction
9. Amplitude recovery
10. Multi-pass swell noise attenuation (shot domain and other domains)
11. Direct arrival noise attenuation
12. Linear noise attenuation
13. Seismic interference attenuation (if applicable)
14. Other noise attenuation: ship noise, cable noise, debris noise
15. De-bubble
16. De-signature to zero-phase; receiver and source de-ghosting for broadband processing; datum to MSL
17. Water velocity correction
18. Shallow water multiple attenuation
19. 3D Surface-Related Multiple Elimination (SRME)
20. Tau-P Deconvolution (If required)
21. Velocity analysis at 2 km X 2 km intervals
22. High-resolution Radon demultiple

23. Intra-bed demultiple and/or additional demultiple methods as required
24. Remnant noise and multiple attenuation
25. Inverse-Q compensation (phase only, data-derived)
26. Time-variant filter (if required)
27. Removal of applied amplitude recovery
28. Offset distribution for pre-migration gathers (including 5D regularisation / interpolation, noise attenuation, Voronoi scaler)
29. Isotropic Kirchhoff Pre-Stack Time Migration (PreSTM) with smooth demultiple velocity field
30. Migration velocity analysis at 1 km X 1 km
31. Isotropic Kirchhoff PreSTM with updated velocity field
32. Anisotropic migration velocity analysis: Vp and interval Eta at 500 m X 500 m; velocity field build-up
33. Anisotropic Kirchhoff PreSTM (optimal dip and aperture)
34. Post-migration velocity analysis at 250 m x 250 m intervals; velocity field build-up
35. Inverse-Q compensation (amplitude only, if required)
36. Post-migration demultiple / noise attenuation
37. High-density stacking velocity analysis
38. Additional gather flattening for AVO studies
39. Trim statics , RMO
40. Final mute testing, stack, and partial angle stacks (Near , Mid, Far)
41. Final Raw stack
42. Post-stack noise attenuation (footprint removal)
43. Post-stack deconvolution (if required)
44. Low frequency enhancement
45. Time-variant filter, low-cut and high-cut filter, Dip filtering (if required)
46. Spectral balancing / amplitude recovery (if required)
47. Coherency enhancement (if required)
48. Polarity to SEG normal

5.2 Depth Domain Processing Workflow (Pre-SDM)

5.2.1 Initial Setup

1. Data input: pre-migration offset gathers, well data (if available), and PreSTM velocity field
2. Horizon picking: minimum 3 horizons interpreted on time-migrated stack for PSDM
3. Initial velocity model: derived from PreSTM velocities converted to interval velocities in depth, then spatially smoothed

5.2.2 Velocity Model Iteration (up to 5 iterations)

Iteration 1:

- Isotropic Kirchhoff Pre-Stack Depth Migration (PSDM)
- CMP gather preconditioning
- Tomographic velocity update at appropriate intervals as approved by DGH
- Test-line QC: gathers, stack, Gamma/Delta velocity

Iteration 2:

- Anisotropic parameter analysis (epsilon and delta); well calibration if available; horizon-guided anisotropic property distribution
- Anisotropic Kirchhoff PSDM (TTI)
- CMP gather preconditioning
- Tomographic velocity update at appropriate intervals as approved by DGH
- Test-line QC: gathers, stack, Gamma/Delta velocity

Iterations 3 to 5 (minimum 4; 5th if required): Repeat iteration 2 steps with QC after each.

5.2.3 Final PSDM Processing

4. **Full Waveform Inversion for velocity model building:** Band Frequency will be decided depending on input data S/N, complexity of near surface velocity. The FWI workflow shall include iterative velocity model updates, starting with low-frequency data to resolve large-scale structures, followed by high-frequency iterations for fine-scale details, constrained by available well data
5. Final Anisotropic Kirchhoff PSDM (TTI) / Beam Migration— optimal dip, aperture, depth step, and output depth using velocity model from FWI
6. Production volume QC and mis-tie analysis (horizons and well markers if available)
7. Sort to CMP domain
8. Post-migration velocity analysis (high-density)
9. Inverse-Q compensation (amplitude only, if required)
10. Post-migration demultiple and noise attenuation
11. Raw stack
12. Gather flattening for AVO studies; partial angle stacks
13. Trim statics, RMO
14. Final stack
15. Post-stack noise attenuation
16. Post-stack deconvolution (if required)
17. Time-variant filter; low-cut and high-cut filter (if required)
18. Spectral balancing / amplitude recovery
19. Low frequency enhancement
20. Coherency enhancement
21. Polarity to SEG normal

NOTE:

Amplitude relations (AVO characteristics) shall be preserved throughout all processing steps except post-stack scaling or image enhancement procedures. Close interaction with DGH QC personnel is required for finalization of PreSTM, PreSDM, and optional processing parameters.

5.3 3D Processing Key Personnel

Position	Minimum Experience	Minimum Headcount
Project Manager (Processing)	10 years, including ≥ 5 years as Project Manager (3D Marine Seismic Processing)	2
Senior Processing Geophysicist	7 years, including ≥ 5 years as Senior Processing Geophysicist (Time and/or Depth, 3D Marine)	4
Processing Geophysicist	5 years, including ≥ 3 years as Processing Geophysicist (3D Marine, Time and/or Depth)	5

5.4 Infrastructure & General Processing Requirements

- SERVICE PROVIDER shall deploy all required hardware, software, tape drives, plotters, printers, and peripheral equipment.
- EBCDIC headers shall be provided for all processed data in standard prescribed formats.
- DGH representatives shall participate actively at key processing stages; simultaneous knowledge transfer to DGH is required.
- Weekly and monthly progress reports shall be submitted covering processing steps completed and percentage of total volume processed.
- All QC displays generated as standard procedure or specifically requested by DGH shall be produced and documented.
- Section displays scales: Horizontal 6 cm = 1 km (normal) or 6 cm = 2 km (reduced); Vertical 5.0 inch/sec or 2.5 inch/sec.

6. SEISMIC DATA INTERPRETATION

6.1 Interpretation Objectives

The broad objective is to build a comprehensive tectonic, basin, and petroleum system model supporting hydrocarbon prospectivity assessment. Specific objectives include:

- Mapping key structural and stratigraphic horizons.
- Time-to-depth conversion using calibrated velocity models.
- Identification, analysis, and ranking of hydrocarbon leads and prospects.
- Recommendation of exploration drilling locations.

6.2 Data Integration

Before commencing interpretation, the SERVICE PROVIDER shall collect and integrate all relevant geoscientific data from DGH and publicly available sources, including but not limited to:

- Geological data and stratigraphic reports.
- Aerial photographs and satellite imagery.
- Gravity and magnetic data and associated reports.
- Existing and vintage seismic data from the area and nearby basins.
- Well logs, petrophysical data, pressure/production data, and well completion reports (where available).
- All available geoscientific reports pertaining to the area.

6.3 Indicative Interpretation Workflow

6.3.1 Well-to-Seismic Calibration

- Digital well log QC, display, and stratigraphic analysis.
- Synthetic seismogram computation using sonic, density, and check shot/VSP data.
- Seismic well-tie and horizon identification.

6.3.2 Structural & Fault Interpretation

- Mapping of minimum 5 correlatable horizons from near-top basement to water bottom.
- Fault picking, correlation, and mapping; detailed fault pattern analysis.
- Fault-seal analysis; interpretation of deformational systems, stress/strain directions, and fault interplay.

6.3.3 Stratigraphic Analysis & Seismic Stratigraphy

- Sequence stratigraphy mapping.
- Recognition of seismic stratal patterns and stratal terminations (onlap, truncation, pinch-out etc.).
- Seismic facies analysis and depositional environment assessment using seismic attributes.

6.3.4 Map Generation

- Two-Way Time (TWT) contour maps on all interpreted horizons.
- Isochron computation, analysis, and isochron & isochronopach maps.
- Time-to-depth conversion and depth contour maps.
- Isopach maps.

- Velocity maps.
- Seismo-geological sections and fence diagrams.

6.3.5 Seismic Attribute Analysis

- AVO analysis: Intercept, Gradient, Fluid Factor attributes.
- P-impedance sections through seismic inversion.
- Amplitude extraction along key horizons and discrete stratigraphic intervals.
- Generation of other relevant attributes (coherence, variance, sweetness, spectral decomposition, etc.).

6.3.6 Prospect Generation & Ranking

- **Petroleum system modelling** incorporating global analogues where applicable.
- Structural and stratigraphic lead analysis: entrapment, reservoir extent.
- Prospect generation, risking, and ranking by overall geological merit.
- Identification and recommendation of exploratory drilling locations.
- Recommendation of future exploration strategy and development programme.

6.4 3D Interpretation Key Personnel

Position	Minimum Experience	Minimum Headcount
Project Manager (Interpretation)	10 years, including ≥ 5 years as Project Manager (3D Seismic Interpretation)	2
Senior Interpretation Geophysicist and Geologist	7 years, including ≥ 5 years as Senior Interpretation Geophysicist/Geologist (3D)	4
Interpretation Geophysicist and Geologist	5 years, including ≥ 3 years as Interpretation Geophysicist / Geologist(3D)	5

NOTE: Above mentioned workflows are indicative in nature, however multi-client companies may adopt improved processing and interpretation workflows and their proprietary technology for generating best image for delineation hydrocarbon bearing zone

7. QUALITY CONTROL

7.1 QC during 3D Data Acquisition

7.1.1 On-board QC System Requirements

- Real-time subsurface midpoint coverage monitoring using UTM orthogonal grid; CMP coverage for 3D seismic.
- Hard disk storage with backup for all grid coverage data; real-time CRT display.
- Compass/acoustics statistics printout at end of each line: individual mean, standard deviation, average feather angle, midpoint angle.
- Coverage prediction utility for planning subsequent and infill lines.
- Edit facility for bad traces and shot points.
- Facility for automatic rejection of bad compasses in real time.

7.1.2 QUALITY CONTROL SYSTEM-SPECIFICATION & STANDARDS

- The system should have sufficient disc memory and capable of dividing the survey area into the requisite storage bins and store all offset coverage in a permanent grid database.
- The system shall be capable of providing hard copies of partial and total grid coverage plots or listings in order to determine whether or not sufficient offset coverage has been obtained. The system shall provide a track plot of cable midpoint angles throughout a line.
- The system shall have the ability to recalculate the grid data if cable compass or navigation data is found to be below specifications or if particular lines are to be added or subtracted from the database. DGH has the option of not adding the data to the grid base after a line has been shot.
- The system should allow for dividing the streamer into a minimum of 4 segments and furthermore shall have the capability of verifying that the specified offset distribution has been achieved.
- Facility for automatic rejection of bad compasses in real time should be available.
- The system shall be capable of providing a display in real time of the midpoint distribution of reflection points from each streamer segments.
- All mid-point coverage data shall be recorded on cartridges in case of a failure within the data base storage system.
- Mid-Point Coverage:

i) The data shall be collected utilizing fixed sub-surface gather bins to obtain a nominal fold per CMP coverage as per. Each fixed sub-surface area gather bin shall contain a minimum number of traces segment wise as follows:

- 80% of all midpoints from the near quarter of the streamer
- 90% of all midpoints from the second quarter of the streamer
- 70% of all midpoints from the third quarter of the streamer
- 60% of all midpoints from the fourth quarter of the streamer
- The above shall be achieved after removal of all bad traces/ channels; bad shot points, duplicate offsets and flexible binning of 25% on the first group tapered linearly to 100% for the last group.

Note: Steering to be done in Second quarter of the streamer

ii) If required, the vessel may steer off the pre-plotted line to compensate for streamer feather due to tides and currents to provide optimum midpoint coverage. Quality Control of sub-surface coverage and bin content shall be carried out by Contractor's personnel on-board the vessel.

iii) In area having obstructions like Rig and Platform, there will be hole in 3D mosaic about 500-meter radius of the obstruction, which will be accepted by DGH.

iv) The cost of infill line to achieve the specification shall be borne by service provider

7.1.3 Compass & Depth Detector Standards

Item	Specification (12,000 m streamer — pro-rated for other lengths)
Minimum operational compasses	30 of 40; one each at near and far ends
Q-Marine streamers	Minimum 24 of 30 operational
Compass rejection criterion	Bias > 0.5°, or > 5 successive bad values, or > 15% bad values on any line
Minimum operational depth detectors	20 of 30; one each at near and far ends
Streamer depth tolerance	Within ± 1 m of chosen depth

7.1.4 Conditions for NOT Commencing a Line

Work shall NOT commence on any line if any of the following conditions exist:

- More than 2% of traces per streamer are bad.
- Fewer than 80% depth detectors are operational per streamer
- Streamer depth varies more than 1 m from the chosen depth.
- Fewer than 80% compasses are operational per streamer, or any two adjacent compasses are non-operational
- Streamer drift exceeds 10°, unless authorised by DGH representative.
- Ambient noise not at lowest level consistent with sea conditions.
- Instrument noise exceeds manufacturer's specifications.
- Electrical source noise (e.g. 50/60 Hz) is present. (Must be eliminated without notch filter.)
- Air-gun array below normal operating pressure or array volume < 90%.
- DGPS not providing required positional accuracy.
- On-board single-trace recorder, monitor camera, fathometer, or energy source monitor is inoperative.
- Gun string separation more than $\pm 20\%$.
- Gun depth deviates more than ± 1 m from planned depth.
- Time break error detected.

7.1.5 Conditions for STOPPING an In-Progress Line

Work shall STOP on an in-progress line if any of the following occur:

- More than 2% of traces per streamer become bad.
- More than 2 adjacent depth detectors become non-operational.

- More than 10% reduction in air-gun volume or operating pressure.
- More than 2 adjacent guns of similar volume, or any critical gun, not operating.
- Auto-firing of any gun, or gun controller malfunction.
- Fathometer inoperative for more than 1 hour.
- Single-trace recorder inoperative for more than 30 minutes.
- 6 consecutive recordings missed or bad.
- More than 5% cumulative bad shots on the line.
- DGPS/GNSS not providing required accuracy.
- Streamer depth varies more than 1 m from chosen depth.
- Streamer drift exceeds 10° relative to line heading, unless authorised.
- More than 2 adjacent compasses non-operational.
- Energy source cannot be monitored.
- Gun string separation more than $\pm 20\%$.
- Gun depth deviation more than ± 1 m from planned depth.
- Time break error.

7.1.6 Definition of Bad Shots

Condition	Classification
Auto-firing of guns	Bad shot
Gun firing time deviation $> \pm 1$ ms	Bad shot
Loss of $> 10\%$ of array volume	Bad shot
Pressure drop $> 10\%$ of normal operating pressure	Bad shot
Parity errors exceeding manufacturer specifications	Bad shot
Sync errors present	Bad shot
Non-recording of positioning data	Bad shot
Non-recording of data on cartridge (any reason)	Bad shot
Data recorded with incorrect instrument settings	Bad shot
Loss of positioning data	Bad shot
Poor correlation between individual source array signatures	Bad shot

7.1.7 Definition of Bad Groups

Condition	Classification
Leakage value < 500 k Ω	Bad group
Dead / no response	Bad group
Intermittent / sluggish / spiky response	Bad group
Noise exceeds limits specified in Section 4.10	Bad group
Amplitude variation $> \pm 6$ dB relative to adjacent traces (non-coherent)	Bad group
Reverse polarity	Bad group

NOTE: Work standards may be relaxed by DGH's on-board representative in exceptional circumstances, provided data quality is not compromised.

7.2 QC during 3D Data Processing

Quality control of data processing is the responsibility of the SERVICE PROVIDER. DGH requires that the final processed seismic data is free from all significant geophysical errors and is delivered on schedule. DGH representatives shall have timely access to workstations with real data access and screen-dump capability.

Mandatory QC products include but are not limited to:

- Shot record display for bad/noisy trace editing.
- Edited shot display: auto-editing/de-spiking results.
- S/N ratio and RMS amplitude display over zone of interest.
- Navigation merge verification: source-receiver distance, gun firing sequence, source-cable shape plot, first-break analysis, near-trace gather.
- Source signature plot before and after signature deconvolution.
- Amplitude and power spectrum before and after each process on gather and stack.
- Gather/stack RAP plots for geometrical spreading/exponential gain/offset-dependent gain.
- PSTM corrected gather displays at intermediate velocity analysis locations.
- Mute panel and TVF selection panel displays.
- Fold of coverage

Parameter testing shall be conducted but not limited to:

- True amplitude recovery optimisation.
- Flex binning options.
- Pre-stack multiple/noise attenuation.
- Mute testing (front-end, top mute, inside trace mute).
- Post-stack random noise attenuation.
- Q compensation (amplitude and phase).
- Post-stack deconvolution and spectral balance.
- Migration tests: up to 5 velocity percentages , dip, aperture, impulse response
- Filter and scaling tests.
- Residual Amplitude Compensation (RAC) with space-varying option if required.
- Service provider shall carry out the test for all processing steps and apply as per approval by DGH

7.3 QC during 3D Data Interpretation

Interpretation shall follow a structured workflow to minimise uncertainty. Key QC stages:

- Data Compilation & Quality Assessment: Evaluate seismic resolution, signal quality, phase consistency, navigation accuracy, and processing reliability before commencing interpretation.
- Regional Geological Understanding: Establish basin tectonics, depositional history, stratigraphy, and petroleum system elements as interpretation context.
- Well-to-Seismic Calibration: Use sonic, density, check shot, and VSP data; generate synthetic seismograms; tie geological markers to seismic reflections.
- Horizon & Fault QC: Ensure consistent identification across all seismic lines; validate structural closures and fault geometries.
- Attribute QC: Validate seismic attributes against geological expectations; cross-check with well data where available.
- Velocity & Depth Conversion QC: Validate calibrated velocity models against well-marker depths.

- **Uncertainty & Risk Assessment:** Continuously evaluate uncertainties in velocity assumptions, structural interpretation, and geological models.
- **Integration QC:** Cross-validate interpretation with petrophysical, geochemical, gravity, magnetic, and geological datasets.
- **Documentation:** Maintain detailed records of interpretation workflows, assumptions, mapping decisions, and final outputs.

8. DELIVERABLES (3D API)

All deliverables shall be provided in the quantities and formats specified. Any deliverable not explicitly listed but deemed necessary for completeness shall be supplied at no additional cost to DGH. The SERVICE PROVIDER shall **mandatorily upload** all acquired, processed and interpreted data to the National Data Repository (NDR) Cloud.

- The acquired field data post validation and quality checks is to be uploaded on a monthly basis throughout the acquisition period.
- The processed and interpreted data to be uploaded post processing/ interpretation, validation and quality checks.

All data submissions shall be made in duplicate. The first copy shall be uploaded to the NDR Cloud, and the second copy shall be submitted through physical storage media such as Cartridge, Hard Disk, or any other approved hardware medium.

8.1 3D Acquisition Deliverables

Medium: 1 copy on LTO-07/08 + 1 copy on SSD. Reports: 2 hard copies + 2 digital copies on SSD. Others: as required by DGH.

Category	Content	Format
Field Data	Raw seismic data	SEG-D
	Navigation merged shot gathers	SEG-Y
	Tidal statics/table	ASCII
	Far-field gun signature	SEG-Y & ASCII
	Near-field gun signature	SEG-Y & ASCII
Navigation Data	Raw navigation data (P2/94 or IOGP P2/11)	ASCII
	Processed navigation data (P1/90 or IOGP P1/11)	ASCII
	Bathymetry report	PDF
On-board QC Data	Brute stack (per line)	SEG-Y
	Picked velocity (for brute stack)	ASCII / requested format
	RMS plot per line (shot vs channel vs amplitude)	SEG-Y
	LMO plot	SEG-Y
	Near Trace Cube	SEG-Y
Reports & Logs	Observer logs/reports (per line)	PDF
	Navigation logs/reports (per line)	PDF
	Operation reports (observer, navigation, QC, other departments)	PDF
	Daily and consolidated monthly reports (per Appendix II format)	PDF
	Monthly production certificates	PDF
Other	SEG-Y wire frames for all deliverables	PDF

Category	Content	Format
	Block/area completion certificates	PDF
	Pre- and post-plot maps (appropriate scale)	Maps
	Location map	PDF

8.2 3D Processing Deliverables

Medium: 1 copy on LTO-07/08 + 1 copy on SSD. Reports: 2 hard copies + 2 digital copies on SSD. Others: as required by DGH.

8.2.1 PreSTM Outputs

#	Item	Format
1	Geometry-merged shot gathers	SEG-Y
2	Final pre-migrated CMP gathers (input to PSTM)	SEG-Y
3	Raw PreSTM gathers (no mute, with NMO)	SEG-Y
4	Raw PreSTM gathers (no mute, without NMO)	SEG-Y
5	PreSTM gathers after gather conditioning (mute + NMO applied)	SEG-Y
6	Final pre-migrated stack section	SEG-Y
7	Raw PreSTM stack (no conditioning)	SEG-Y
8	Final PreSTM stack (with and without scaling)	SEG-Y
9	Final PreSTM partial angle stacks (selected angles)	SEG-Y
10	Final migration RMS velocity fields for PSTM (with and without smoothing)	SEG-Y
11	Final stacking velocity fields (after high-density picking)	SEG-Y & ASCII
12	Final Eta model	SEG-Y

8.2.2 PreSDM Outputs

#	Item	Format
1	Final pre-migrated CMP gathers (input to PSDM)	SEG-Y
2	Raw depth-migrated gathers in depth and stretched to time	SEG-Y
3	Final depth-migrated gathers after gather conditioning (depth domain)	SEG-Y
4	Final depth-migrated gathers after gather conditioning (stretched to time)	SEG-Y
5	Raw depth-migrated stack	SEG-Y
6	Unscaled depth-migrated stack	SEG-Y
7	Scaled depth-migrated stack	SEG-Y
8	Unscaled depth-migrated stack converted to time domain	SEG-Y
9	Scaled depth-migrated stack stretched to time	SEG-Y

#	Item	Format
10	Final PreSDM partial angle stacks (selected angles, stretched to time)	SEG-Y
11	Final interval velocity model (depth domain smooth and unsmooth)	SEG-Y & ASCII
12	Final anisotropic parameters (Epsilon, Delta, and Eta model)	SEG-Y
13	FWI derived velocity model	SEG-Y & ASCII
14	Final Gathers and Stacks(Raw & Final) from RTM	SEG-Y

8.2.3 Ancillary Processing Data

#	Item	Format/Media
1	Final P1/90 or IOGP P1/11 file used for geometry assignment	ASCII / SSD
2	Trace editing tables	ASCII / SSD
3	Tidal table/static	ASCII / SSD
4	Final mute file	ASCII / SSD
5	Final migration velocity field for PSTM (with and without smoothing)	ASCII / SSD
6	Final stacking velocity field (high-density picking)	ASCII / SSD
7	SEG-Y wire frames for all deliverables	ASCII / SSD
8	Subsurface coverage/fold maps (1:25,000 and 1:50,000)	CGM & PDF / SSD
9	Picked horizons on time-migrated sections	ASCII / SSD
10	Water bottom map for each profile	ASCII / SSD
11	Final processing report and presentation (6 copies on SSD + hard copies)	PDF / SSD
12	Base map (scales 1:50,000 / 1:100,000 / 1:250,000)	PDF/CGM / SSD
13	Final structural parameters (Dip and Azimuth model)	SEG-Y / SSD

8.2.4 SEG-Y Tape/Media Header Requirements

All SEG-Y deliverable media headers shall include:

- Complete projection system description: spheroid name, projection, central meridian.
- Total and live line/trace counts.
- Group interval and source interval.
- Summary of acquisition parameters and processing sequence.
- Polarity of processed data.
- Data in SEG-Y IBM 32-bit floating-point format with line number, trace number, CDP, X, Y in respective header words.
- No embedded EOFs; structure: 3200-byte EBCDIC header, 400-byte binary header, data traces in sequence, EOT.

- All deliverables properly labelled and annotated.

8.3 Interpretation Deliverables

Delivered as: 2 hard copies + 2 sets of soft copies on SSD or Drop Site of NDR on agreed frequency with DGH.

8.3.1 Hard Copy Outputs

- Comprehensive final interpretation report.
- All time structure maps and depth structure maps at 1:50,000 and 1:100,000.
- Seismo-geological sections, fence diagrams, and correlations.
- Interpreted seismic sections.
- Fault pattern maps.
- Geoscientific data correlation maps.
- Velocity maps.
- Isopach and isochronopach maps.
- Attribute sections and maps.
- AVO and inversion study results.
- Prospect map and any other relevant maps.

8.3.2 Soft Copy Outputs (SSD and LTO-7/8)

- 3 sets of full interpreted data in ASCII format.
- 3 sets of full interpreted data in compatible SEG-Y format.
- All attribute profiles in SEG-Y format.
- Interpretation project back-up at key QC stages (mutually agreed formats).
- Final interpretation project back-up with all relevant data in SEG-Y format.
- Complete interpretation data and final project in Petrel-compatible format.

NOTE: The final interpretation report must be comprehensive and self-contained, including QC measures, methodologies, workflow sequences with parameters, and inferences from all deliverables.

9. REPORTING & DATA MANAGEMENT

9.1 Observer's Report

With each data shipment, the SERVICE PROVIDER shall deliver the following along with all seismic and navigation data for each line:

- SERVICE PROVIDER and vessel name; seismograph type; recording format; type of data acquisition.
- Client project number and line number; line heading; date.
- Tape/media numbers and corresponding tape-drive identifiers.
- Shot point and file number range; first and last shot point times.
- Indication of test and noise records; misfires with reasons.
- Bad trace changes; average feathering angle (tail-buoy defined) at SOL and EOL.
- Weather and sea state at SOL, EOL, and during changes; average water depth at SOL and EOL.
- Any change in recording parameters; spread geometry

9.2 Tape/Media Labels

Each cartridge/media shall be labelled with:

- SERVICE PROVIDER and DGH logos; vessel name; area/survey name.
- Type of data acquisition; full line number (including prefixes and suffixes).
- First and last shot point and file numbers; data format; recording date.
- Cartridge number; sampling interval; record length.

9.3 Data Shipment Procedures

- First copy of all data tapes shall be shipped to DGH's designated processing centre or archive at the earliest opportunity (or as requested by DGH).
- Second copy shipped once the first copy has been confirmed as successfully read.
- SERVICE PROVIDER is responsible for data safeguarding until second copy is delivered.
- Cartridges containing only rejected lines/segments shall be marked 'DNP' (Do Not Process) and included in all shipments; DNP tapes shall be copied if they contain data.
- Electronic and paper copies of media transmittal forms, verified by DGH onboard representative, shall accompany all shipments.
- An electronic transmittal copy (tabulated, one row per tape, highlighting DNP tapes) shall be emailed to DGH simultaneously with shipment.

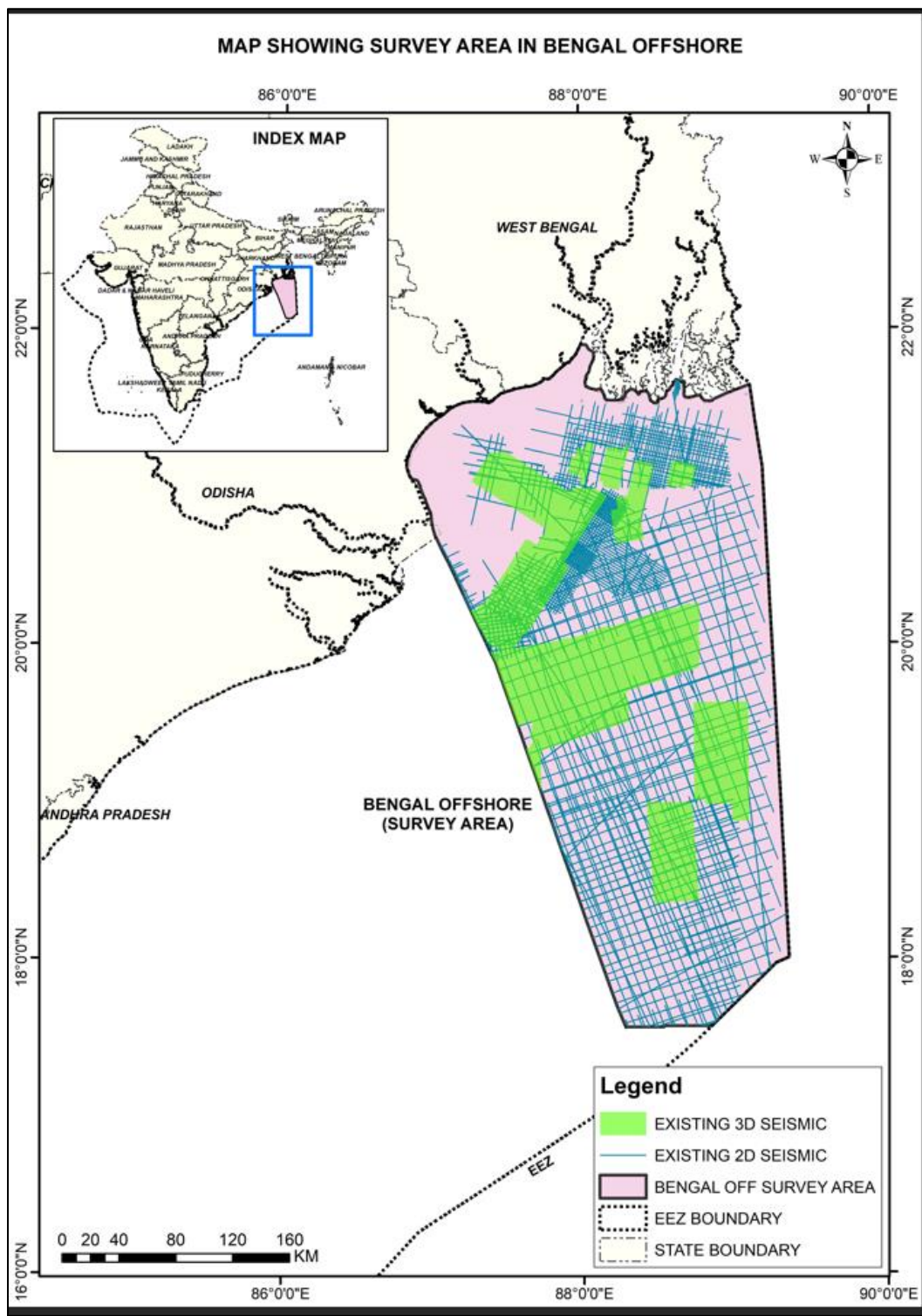
9.4 Navigation Data Processing & Mapping

- Final navigation data processing to P1/90 or IOGP P1/11 and post-plot preparation shall be completed on-board by the SERVICE PROVIDER.
- Both raw (P2/94 and IOGP P2/11) and processed (P1/90 or IOGP P1/11) navigation data supplied to DGH.

APPENDICES

Location Map of the Survey Area

Appendix I



Completion Certificate (Re-processing & Interpretation)

Appendix II

Reference: Contract No. _____

(i) This certifies that M/s XXXXX completed the Re-Processing & Interpretation of xxxxx SKM of 3D and xxxxx LKM of 2D seismic data in Bengal BASIN as specified in the Contract.

Signature: _____ (Project Manager)

Signature: _____ (DGH / Third Party QC Representative)

Daily / Monthly Progress Report Format (Data Acquisition)**Appendix III**

Date: _____ | Project: _____

Sl.	Line No.	SP Range (FSP-LSP)	Chargeable SP (FGSP-LGSP)	Total Chargeable SPs	Bad SPs	Acceptable Shots (e)-(f)	Coverage SKM	Chargeable SKM	Remarks
1									
2									
3									

Summary Items	Values
1) Total Prime Coverage (daily/monthly):	
2) Total Chargeable Prime (daily/monthly):	
3) Total Prime Coverage (project):	
4) Total Chargeable Prime (project):	
5) Total Standby Hours (daily/monthly):	
6) Total Chargeable Standby Hours (daily/monthly):	
7) Total Standby Hours (project):	
8) Total Chargeable Standby Hours (project):	

Party Chief: _____

DGH's Representative: _____

Note :- The Service Provider shall formulate a format for the monthly / quarterly reporting on the progress of reprocessing and interpretation of legacy data in consultation with DGH.

Vessel Acceptance Certificate

Appendix IV

Reference: Contract No. _____

This certifies that vessel _____ has been deployed in area _____ on _____ at _____ hrs IST. All equipment has been fully tested, calibrated, and commissioned as specified in the Contract. 3D Seismic line number _____ / 100 SKM of accepted data on sail-line _____ has been acquired in the survey area.

Signature: _____ (Party Chief)

Signature: _____ (DGH / Third Party QC on-board Representative)

Completion Certificate (3D Seismic Data Acquisition)

Appendix V

Reference: Contract No. _____

(i) This certifies that vessel _____ completed the acquisition of 3D Broadband seismic data in survey area(s) _____ as specified in the Contract.

OR

(ii) This certifies that vessel _____ acquired _____ SKM (_____% of awarded volume of _____ SKM). Remaining volume of _____ SKM could not be acquired due to the following localised obstructions:

- Fixed submerged fishing nets
- Rigs/platforms in the area
- Marine installations
- Restricted area / marine sanctuary / port area
- Very shallow water / exposed land mass
- Other localised obstructions/hazards

Signature: _____ (Party Chief)

Signature: _____ (DGH / Third Party QC On-board Representative)

Demobilisation Certificate

Appendix VI

Reference: Contract No. _____

This certifies that no data pertaining to the above-referenced Contract remains on-board vessel _____ of M/s _____. All data acquired/processed under the Contract has been offloaded. All data in hard disks or any other storage media has been downloaded, cleared, and deleted.

Signature: _____ (Captain)

Signature: _____ (Party Chief)

Checked and confirmed. No data remains on board. All storage media cleared and deleted.

Signature: _____ (DGH / Third Party QC On-board Representative)

Bathymetric Data Metadata Format**Appendix VII**

#	Field	Entry
1	SL No.	
2	Name of Survey Vessel(s)	
3	Sponsoring Agency	DGH
4	Address	
5	Survey Name	3D Seismic Data Acquisition XXXX Basin
6	Survey Area	
7	Survey Period From / To	
8	Datum & Projection	
9	Processing Software Used	
10	Software Version	
11	Processed Data Files Submitted	
12	Weather Conditions	
13	Remarks	

Sensor Information:

#	Sensor	Make / Model	Firmware Version	Calibration Date	Accuracy
a	Position System				
b	Echo Sounder				
c	Motion Sensor				
d	Sound Velocity				

Meteorological Data Format

Appendix VIII

[Meteorological data format table to be provided in accordance with DGH standard templates and relevant Indian Meteorological Department formats.]

SL	Date	Time	Lat	Long	Surface wind		Atmospheric Pressure	Temperature			Weather	Wave data			Tide
								Air Temp	Dew Point Temp	Wet Bulb Temp					
	dd-mm-yy	UTC/IST	DDMMSS	DDMMSS	Speed M/s or Knots	Direction (degree)	Millibars or Hectapascal	TT.T	TdTd.Td	TwTw.Tw	(a) Clear Sky (No clouds) (b) Mainly clear (1-2 Octas clouds) (c) Partly cloudy (3-4 Octas clouds) (d) Mainly cloudy (5-7 Octas clouds) (e) Overcast (8 Octas clouds)	Height (m)	Dir (deg)	Period (Sec)	

Mobilisation Certificate (Re-Processing & Interpretation)

Appendix IX

To,
Director General of Hydrocarbon,
New Delhi

Dear Sir,

This certificate has reference to your Contract No. Dated 20__ on the
subject

It is hereby confirmed that(Name of the Company) have successfully collected all the raw 2D & 3D seismic data along with requisite ancillary information / meta data as per stipulated work quantum from NDR., DGH and has successfully loaded all the data in their work center located -----(location of work center) and is in a ready state to commence the data processing job engaging the computing resources of the work center and deployment of the key personnel of the Subsidiary/Parent company/Sister-Co Subsidiary company/Joint Venture Partner (strike out whichever is not applicable) on whose strength they have complied with the tender's Technical requirement as per the tender qualifying criteria.

Signature
(Name & Designation of Authorized person from DGH)

Signature
(Name & Designation of Authorized person from Service Provider)