Recent developments in multimeasurement marine seismic acquisition and full waveform imaging enable geophysicists to compensate for distortions caused by shallow geology and sharpen images of deep targets to reduce the uncertainty of seismic information.

Hydrocarbon exploration requires that geoscientists understand the geology of prospective reservoirs often located beneath complex rock layers. From the geophysicist’s perspective, the overburden acts as a defective lens, distorting seismic images of deeper geologic structures. As a result, targets appear indistinct, distorted, out of place or, in extreme cases, completely obscured. The geophysicist’s challenge has been to devise methods for peering through the overburden and bringing the underlying geology into focus.

Make-or-break decisions on project viability often hinge on how well prospective reservoirs can be imaged, a key factor determining exploration risk. Operators need accurate images of reservoirs to help them place exploration wells where they effectively test the prospect, conduct field planning and place development wells. In addition to imaging reservoirs, geophysicists must correctly image the overburden—the layers above the reservoir—to reduce drilling risks from operational challenges such as maintaining a stable wellbore and controlling formation pressure.

The value that seismic data adds to the exploration process depends on the quality of the image produced and the cost incurred in acquiring such data. Cost-effective seismic acquisition requires surveying large areas quickly without compromising data quality and while minimizing operational and environmental exposure. Fast acquisition helps shorten the time frame between the decision to evaluate a play and the decision to drill.

High-quality data enable exploration teams to attain a clear understanding of the geology from the seafloor to the target prospect and then to decide whether to test and appraise the prospect. The acquired data must also be suitable for use in advanced processing, imaging, inversion and interpretation workflows. These workflows provide vital inputs for geomechanical, reservoir and basin models.

IsoMetrix marine isometric seismic technology and full waveform inversion processing are enabling imaging of complex structures in frontier areas. The IsoMetrix technology allows for full-bandwidth imaging of fine-scale structures in the subsurface in all directions—inline, crossline and vertical—for detailed imaging from seabed to reservoir. Full waveform inversion results in a model of seismic velocities, which is used with the seismic data to form an image of the geology from the surface to the targets of interest.

This article describes surveys acquired using IsoMetrix technology in offshore Malaysia and the North Sea. The survey results demonstrate the benefits of IsoMetrix technology for overcoming a challenging acquisition environment and increasing spatial bandwidth and of applying full waveform inversion for determining overburden and reservoir properties, specifically seismic velocities.

Improving Data and Image Quality

Good seismic imaging requires a chain of factors: a good acquisition system, optimal survey geometry and accurate processing algorithms and workflows. More than 15 years ago, Schlumberger geophysicists embarked on a program to move from conventional seismic acquisition toward discrete sensor technology. The technology includes improvements in receiver sensitivity and positioning accuracy, steerable streamers, increased source control and point-receiver acquisition, which records traces from individual receivers to provide consistently repeatable high-quality data. These capabilities are evolving. New measurements of the crossline and vertical gradients—
variations with distance—of the pressure wavefield enable the signals received from a marine seismic shot to be processed as a full 3D wavefield rather than as a collection of 2D profiles. In addition, a newly developed, calibrated, broadband marine seismic source provides improved low-frequency signal content; no source notches, or missing frequencies, below 150 Hz for all directions within a 20° cone from the vertical; and cancellation of the source ghost—a delayed reflection of the source from the sea surface.

These acquisition improvements have been complemented by innovations in marine surveying geometries—for example, multivessel shooting and full-azimuth source-receiver configurations. Together, these technologies make it possible to illuminate targets of interest previously obscured by folded or faulted sediment, overlying salt layers or other complex geologic bodies.

Seismic acquisition and survey geometry are only the starting points for seismic imaging. Accompanied by onboard processing capabilities, data reliability has vastly improved. In addition, the application of robust seismic inversion and imaging techniques, such as full waveform inversion and reverse time migration, allow geophysicists to deliver sharper images and estimate rock properties for explorationists and reservoir engineers who develop static and dynamic models of the reservoir. These models are based on the seismic results—images, velocities and horizons—that are integrated with well data. Before drilling, explorationists use the models to predict the petroleum systems present within the seismically imaged volume, define plays and locate prospects for drilling. Reservoir engineers use refinements of these models to plan field development and, later, manage hydrocarbon recovery operations.

**Imaging Between Streamers**

The purpose of IsoMetrix technology is to provide a densely sampled representation of the wavefield in all directions. An idealized seismic acquisition system would be able to record the seismic signals from everywhere below the surface. This capability would maximize the opportunities for separating the signal from unwanted noise and imaging the reflectors in the subsurface. However, conventional seismic data are recorded along only a small number of long streamers towed behind a vessel. Thus, although conventional seismic data are well sampled in recording time and along the streamer (inline), they are not recorded between the streamers (crossline), which may be separated by large distances of 50, 75 or 100 m [164, 246 and 328 ft]. As a result, any waves propagating in the crossline direction may be aliased, or inadequately sampled.

Often, the focus of marine seismic imaging is to thoroughly sample the wavefield in the reservoir. However, good sampling of the wavefield in the overburden is also important because these depths must be imaged correctly to enable the geophysicist to see clearly into the reservoir. Sampling the seabed or other interfaces that generate multiple reflections is important because such reflections interfere with primary reflections. Shallow depths are important because of possible seabed and shallow subsurface hazards to drilling.

Typical marine seismic receivers are hydrophones that record the pressure wavefield only. Reconstruction of the pressure field between streamers requires interpolation between known pressures at each streamer location and results in crossline pressure fields becoming aliased and incorrect.

The IsoMetrix technology is based on the Q-Marine point-receiver marine seismic system and combines hydrophones for measuring the seismic wavefield pressure with a three-component (3C) microelectromechanical systems (MEMS) unit. The 3C MEMS unit contains three orthogonal accelerometers for measuring the full 3D vectorial motion—magnitude and direction—of the recorded wavefield (Figure 1).
By adding 3C accelerometers, the marine receivers record the variation of acceleration, which is proportional to the pressure gradient, or the spatial derivative of pressure with direction. In an acoustic material such as water, hydrophones measure the pressure ($P$) fluctuations caused by the seismic wave. Three-component accelerometers measure the accelerations in three orthogonal directions ($a_x$, $a_y$, and $a_z$). Newton’s Second Law specifies the force that results from a difference in pressure; the force is directed from high to low pressure. The relationship between the difference in pressure with direction—the spatial derivative of $P$—and the acceleration, for example in the $x$ direction, is $\rho \times a_x = -\partial P/\partial x$, where $\rho$ is the material density, and the direction of force is opposite, or negative to, that of the pressure gradient. This type of relationship holds for each spatial direction ($x$, $y$, and $z$) and allows the calculation of the spatial derivative of pressure directly from the acceleration measurement. Consequently, knowing the pressure gradients, geophysicists can reconstruct the unaliased pressure field in all directions. Therefore, geophysicists can estimate the 3D wavefield around the streamers using the same spacing in all directions—inline, crossline and vertical.

Reconstructing the Wavefield
The ability to measure the crossline wavefield gradient enables geophysicists to acquire marine seismic data using streamers spaced farther apart than those in conventional surveys and to reconstruct the 3D wavefield on a dense grid at points between streamers (Figure 2). For example, if the actual recordings were accomplished using eight streamers spaced 75 m apart, providing a streamer spread that is 525 m [1,720 ft] wide, the wavefield may be reconstructed as if it were recorded using virtual streamers spaced a tenth of the distance—7.5 m [24.6 ft] apart. When wide streamer spacing is used, areas of exploration can be surveyed faster and more efficiently using fewer sail lines, thereby reducing survey duration, acquisition cost, operational complexity and exposure to adverse environmental conditions.

Recording the vertical wavefield component improves the geophysicist’s ability to remove noise, particularly ghost reflections, which are always present in marine seismic survey recordings. Ghosts are generated when the upward traveling primary signal is reflected downward by the sea-air interface. This downward traveling ghost is detected by the seismic receivers and, if uncorrected, causes a frequency dependent blurring of the final image. Using the vertical acceleration measurements, the geophysicist can separate the upgoing and downgoing components of the wavefield, thereby facilitating removal of ghost reflections. The ability to remove the ghosts also allows IsoMetrix streamers to be towed deeper than hydrophone-only streamers; towing deep often reduces other sources of noise such as those caused by ocean waves and by the motion of the streamer through the water.

Generalized matching pursuit (GMP) is a processing method that can take advantage of the multimeasurement data delivered by the IsoMetrix technology. The GMP process operates on components of the seismic wavefield that are not confined to traveling straight from the source to the receiver but instead have a significant degree of propagation across the streamer spread. These components may include seismic reflections, diffractions, multiples or other noise modes, and, if not treated correctly, can generate spurious effects in the final images. For example, any energy arriving from the crossline direction, which had been spatially aliased previously in conventional datasets, can now be sampled appropriately using GMP spatially and temporally by taking advantage of the crossline and vertical gradient measurements.

The GMP process is data driven and has proved that it can interpolate the pressure wavefield accurately in the crossline direction, even in adverse situations in which the results from conventional processing would be highly aliased. The output from the GMP process is a grid of data channels spaced 6.25 m [20.5 ft] apart in the inline direction along virtual streamers, which are nominally separated by 6.25 m in the crossline direction.

The ability to image in 3D enables geophysicists to consider seismic survey acquisition designs that depart from common practice, as one operator learned when faced with data acquisition challenges.

Challenging Acquisition Conditions
To clearly define prospects in the South China Sea, geophysicists at PETRONAS Carigali Sdn Bhd acquired a broadband 3D seismic survey offshore Malaysia. The survey area is an elongated rectangle oriented NW–SE. A major N–S striking fault crosses the survey area, and structural dips...
Typically, optimal seismic acquisition geometry for conventional 3D surveys requires shooting parallel to the predominant structural dip direction. This inline direction facilitates close-spaced sampling of the seismic wavefield in the dip direction, in this case W–E, in which the geology has the most variation. In addition, the typical conventional seismic bin, or survey subdivision, into which geophysicists sort seismic traces, is asymmetric and elongated in the structural strike direction, which is the crossline direction.

The no-access zone prohibited the vessel from obtaining full subsurface coverage at the western edge of the survey and presented an acquisition challenge to geophysicists, who considered two options (Figure 4). In the first scenario, they could acquire most of the survey by shooting short lines, spaced 100 m apart, parallel to dip to avoid the no-access area. Then, complete the survey using long lines, spaced 50 m apart, sailing parallel to strike adjacent to the no-access zone boundary; the close line spacing of these strike-parallel lines ensured adequate sampling of the structural dip. Alternatively, they could acquire the entire survey using exclusively strike-parallel sail lines.

The first option was inefficient because of the two acquisition directions, which required nonproductive time during the many turns and while the streamers were repositioned for close spacing. The second option was more efficient for acquiring data but risked degrading the seismic information if acquired using conventional technology. According to conventional wisdom, the strike-parallel survey direction, which had typical line spacing and sampling of the seismic wavefield in the dip direction, was not ideal for imaging the subsurface and meeting the objectives of company geologists and geophysicists.

The company used IsoMetrix technology, which enables symmetric, isometric, or equidistant, sampling of the wavefield in the inline and crossline directions, to acquire the survey parallel to the structural strike. In addition, the company acquired a smaller swath of data in the direction of the dominant structural dip, which would allow comparison and validation of the integrity of survey shooting in strike.

The data were acquired using ten 8-km [5-mi] long streamers spaced 100 m apart. The streamers were towed at a water depth of 18 m [59 ft] to minimize noise from variable currents and inclement weather during the survey campaign.

Figure 3. Geologic structure. In the time structure map of the horizon of interest (left), the contour interval is 100 ms two-way traveltime. The black area is a major fault surface that dips to the east. The white quadrilateral is the survey area, and a no-access area is west of it. The fault is 5 to 8 km [3 to 5 mi] wide, has a N–S strike and a throw of about 2.5 s two-way traveltime. The horizon map on the right—the surface area at the prospective reservoir level—shows structural dips that have been estimated from legacy seismic data. The dips are aligned along a W–E trend.

Figure 4. Acquisition options. The survey was restricted by a no-access area on its western boundary. The company geophysicists considered two options for acquiring the seismic data. In the first option (left), the acquisition vessel would sail the main survey area in the dip direction and then reconfigure the streamers and sail the patch survey area, adjacent to the no-access boundary, in the strike direction. In the second option (right), the entire survey area would be acquired by sailing in the direction of geologic strike and would parallel the no-access boundary. The company chose the second option and elected to use IsoMetrix technology, which allows for reconstruction of the wavefield sampled equally in both inline and crossline directions, to acquire the data.

Scenario 1
Main Survey Area
E–W shooting
10 streamers, 8,000 m long, towed 100 m apart
Patch Survey Area
N–S shooting
10 streamers, 8,000 m long, towed 50 m apart

Scenario 2
Entire Survey Area
N–S shooting
10 streamers, 8,000 m long, towed 150 m apart
During seismic processing, the streamer data are processed and output to a 6.25-m × 6.25-m grid that is 8,000 m long and 950 m wide.
After acquisition, the data were preprocessed and then the full 3D wavefield was calculated using simultaneous interpolation and deghosting by means of the GMP method. Next, the upgoing pressure wavefield (P-wave) was output on a 6.25-m by 6.25-m grid for each shot record for further processing and imaging.

The data proved to be of high quality. For example, a map of the seafloor surface showed sand banks similar to those observed in bathymetry data obtained using a high-resolution multibeam echo sounder (Figure 5). Upon comparing the dataset acquired in the strike direction with that acquired in the dip direction, geophysicists judged the datasets to be similar (Figure 6). The fine spatial sampling of the wavefield in the inline and crossline directions obtained with IsoMetrix technology enabled the company to accomplish its geologic and geophysical objectives and achieve acquisition operational efficiency.

In addition to freeing up constraints on seismic survey acquisition design, uniform inline and crossline data wavefield estimation facilitates the increase in spatial resolution and bandwidth required to compensate for distortions caused by shallow overburden layers and to sharpen images of deeper targets. These improvements in resolution and bandwidth helped reduce the uncertainty of seismic information across the operator’s drilling prospects.

Broadband in 3D

Oil discoveries at three locations in the southwest Barents Sea have generated significant interest in exploration of the region. The discoveries offshore northern Norway at the Gohta prospect in 2013 and at the Alta prospect in 2014 were both by Lundin Norway AS; those at the Wisting Central prospect in 2013 were by OMV (Norge) AS. The Gohta and Alta discoveries were west of the Loppa High, a roughly 150 km [90 mi] long and 100 km [60 mi] wide tilted fault block that has been affected by a series of events in the North Atlantic Ocean that include:

- Paleozoic rifting
- Mesozoic opening of the North Atlantic Ocean and of the Greenland and Norwegian seas
- Quaternary glaciation.
8. In this context, phase refers to a wave of a single frequency in a wave train. The phase could be of a compressional (P) wave, shear (S) wave, other waves or their associated reflections and refractions; the wave’s velocity is the phase velocity.


The WesternGeco seismic vessel Western Trident acquired the East Loppa Ridge survey in 2014. The survey covered 4,777 km² [1,844 mi²] and is part of the Schlumberger Multiclient Barents Sea program. The program used IsoMetrix technology to record wide spatial bandwidth data—the recorded wavefield contains the fine-scale detail necessary to represent subsurface geology accurately.

In conventional 3D seismic surveys, a common objective is to acquire broadband surveys of high temporal—traveltime—bandwidth and resolution. The ideal broadband survey has a wide band, or range, of frequencies and is acquired at a high sample rate. The objective for maximizing temporal bandwidth is primarily to maximize resolution in depth—to image thin beds and small faults.

Geology is best understood by observations in three dimensions, which requires maximizing spatial bandwidth in all directions. In the spatial domain, the wavenumber (k) is the spatial frequency, or the number of wavelengths—wavecycle lengths—λ per unit distance. The wavenumber is analogous to the temporal frequency (f) or the number of wave periods—wave-cycle times—T per unit time. Wavenumber in the space domain and frequency in the time domain are related through the phase velocity (v_p), which is equivalent to wavelength divided by period (v_p = λ/T), frequency divided by wavenumber (v_p = f/k) or wavelength times frequency (v_p = λ × f). Consequently, for 3D seismic imaging of geology, the notion of broadband must be expanded to include 3D spatial bandwidth and resolution.

The East Loppa Ridge survey was acquired using 12 streamers that were 7 km [4.3 mi] long, spaced 75 m apart and towed at a constant depth of 25 m [82 ft]. After acquisition, the datasets were preprocessed and then simultaneously spatially dealiased and receiver-deghosted in 3D by means of the GMP method.

The tectonic, stratigraphic and petroleum systems geology of the southwest Barents Sea region is complex. The structural setting resulted from several tectonic events that established a dense mosaic of fault systems (Figure 7). The Loppa High graben and the Bjørnøynena fault complex separates the Loppa High from the Bjørnøya basin (not shown) on the west. Sections A and B (right top and bottom) display grabens associated with the fault systems. The northern portion of the Loppa structure is in the center of Section A. Section B shows graben structures in the north associated with the Hoop fault complex and in the south associated with the Asterias fault complex, which separates the Loppa High from the Hammerfest basin.

Figure 7. Fault system. This seismic time slice (left) at 1,100 ms is through the Loppa High; the seismic attribute is displayed to emphasize the variance in seismic reflectivity—areas of high variance values are colored from black to red and yellow. Three major fault systems, which show up as areas of high variance, affected the Loppa High. The W–E striking Asterias fault complex crosses the Loppa structure in the south; the southern portion of the SW–NE striking Hoop fault complex cuts across and forms the narrow Loppa High graben. The W–E striking Asterias fault complex crosses the Loppa structure in the south; the southern portion of the SW–NE striking Hoop fault complex cuts across and forms the narrow
The Gohta and Alta oil discoveries were in reservoirs located in carbonates of the Gipsdalmen Group, which were deposited in warm, shallow marine environments during the Late Carboniferous to Permian periods and, since then, have been altered by dolomitization and karstification (Figure 8). Additional petroleum systems elements in the Loppa High area include reservoir prospects in Triassic sandstones, source rocks in Carboniferous synrift and postrift sediments and in Permian and Triassic sediments and seals formed by Triassic and Cretaceous shales. The broadband East Loppa Ridge seismic dataset offers an opportunity for detailed interpretation of the complex geology in the Loppa High area.

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Oil has been discovered in the upper Triassic Snadd Formation but at locations with low reservoir quality. Within the Snadd Formation, the broadband seismic data reveal the fluvial system and aid automated mapping, which should reduce the uncertainty of locating higher quality reservoir sands. The data show complex

Loppa High area contains three major fault complexes. The Asterias fault complex forms the southern boundary, which separates the Loppa High from the Hammerfest basin to its south. The southern portion of the Hoop fault complex strikes SW–NE and cuts across the Loppa structure as a narrow graben. The Bjornoyrenna fault complex separates the Loppa High from the Bjornoya basin on the west. Broadband seismic images make it possible to delineate the fault patterns and establish the regional structural framework within the East Loppa Ridge survey area. The structural framework influences local petroleum systems.

Figure 8. East Loppa regional seismic section. The seismic section (top) runs from the Loppa Ridge in the west toward the Otta basin in the east. The interpretation (bottom) is a balanced section, which was modeled using the Dynel 2D restoration and forward modeling tool. This section shows extensional rifting and synrift and postrift sediment deposition during the Carboniferous period. During the Late Carboniferous to Permian, a carbonate platform developed and evaporate was deposited. During the lower to middle Triassic uplifting and tilting of the Loppa High, karstification of the carbonates and sedimentation of shales occurred. The upper Triassic and Jurassic periods were characterized by high clastic sedimentation rates and floodplain development from rivers and deltas. Rifting occurred again during the upper Jurassic to lower Cretaceous; the base Cretaceous unconformity (BCU) defines the transition from synrift to postrift sedimentation. Finally, Tertiary sediments occur above the BCU to the seafloor.
fluvial and floodplain geology and reveal that the channel system is associated with floodplain development (Figure 10). The data reveal a variety of fluvial features, including point-bar systems, clustered channel fill complexes and ribbon-channel sandstone bodies; the ribbon channels were at depths greater than 1,000 m [3,280 ft] and estimated to be less than 100 m wide.

The East Loppa Ridge survey demonstrates the imaging power of acquiring true 3D, broadband seismic data. High spatial resolution in all directions facilitates and improves imaging of complicated 3D geology such as fault networks, anastomosing fluvial channel complexes and carbonate platform deposition and karstification. The increased detail offered by broadband images promotes improved understanding of petroleum system geology and better discrimination of lithologies and their rock properties.

**Full Waveform Inversion**

Geophysicists use full waveform inversion (FWI) for calculating horizontal and vertical seismic wave velocities of geology from the surface to targets of interest. The result is a velocity image in depth that reveals the sought-after structural and depositional information.

Traditional migration produces an image of the subsurface by attempting to reposition, or migrate, seismic data reflection points to their correct locations in 3D space. A velocity model is almost always an input to migration; and a refined velocity model may be a byproduct of migration.

Unlike conventional migration, FWI is a method for building a velocity model by attempting to match the complete recorded wavefield that results as seismic waves travel through the Earth and encounter changing properties in the subsurface geology. The starting point for FWI is an approximate model of velocities. Geophysicists use this velocity model to simulate the recorded wavefield. They then subtract the simulated wavefield from the observed wavefield to obtain the residual wavefield. The residual wavefield is then backward propagated—extrapolated downward in space or backward in time—through the velocity model to obtain a dataset of velocity gradients. These gradients inform where to increase or decrease velocities but not by how much. To calculate a velocity model update, the gradients are multiplied by a step length, which scales the gradients. The velocity updates are added to the current velocity model to create a new velocity model, and the process is repeated. The iterations continue until the residual wavefield is acceptably small, meaning that the modeled wavefield closely approximates the observed wavefield. The final model of seismic velocities can be used as an input to migration to produce an image that better represents subsurface rock characteristics or may be used directly to interpret rock and fluid properties.

This technique was used in Mariner field, discovered in 1981 and located about 150 km [93 mi] east of the Shetland Islands on the UK Continental Shelf in the North Sea. The field is under development by operator Statoil UK Limited with partners JX Nippon Exploration and Production (UK) Limited and Dyas UK Limited. The field consists of two reservoirs. The shallow reservoir contains heavy oil of 14.2 API gravity and is at the base of the Early Paleocene Våle Formation at depths of 1,400 to 1,500 m [4,590 to 4,920 ft] below sea level.

The Mariner field presents various challenges for seismic imaging. The deeper reservoir in the Maureen sandstone member contains heavy oil of 14.2 API gravity and is at the base of the Early Paleocene Våle Formation at depths of 1,400 to 1,500 m [4,590 to 4,920 ft] below sea level. The shallow overburden above the reservoirs contains channel sands that have higher seismic velocities than those of surrounding geologic units. These sands can be mapped easily, but their presence causes distortions in the images of the reservoir zones beneath them. For example, shallow, high-velocity channel sands cause pull-ups of, or apparent structural high spots in, underlying reflectors. The Heimdal reservoir sands consist of complex channel sands as well as sand injectites, or sand intrusions; these sands are difficult to image because of their low impedance contrast with the shales that host them. The Maureen sandstone contains small-scale faults and calcite layers that are important for developing production from the
The geophysicists wanted to know whether the results of FWI would isolate the velocities in shallow channel sands within the overburden. As a test, one of the known channels delineated from legacy 3D seismic data was inserted into the initial velocity model and given a higher velocity than its host units. If successful, the FWI method would sharpen the velocities within this control channel but also pick out other channels in the area.

To compensate for velocity imprecisions introduced by interpolation, the geophysicists applied one iteration of common image point (CIP) tomography to the interpolated velocity model. Common image point tomography is an iterative method of inverting for seismic velocities using seismic reflections. During an iteration, the amount of residual moveout—depth variation—along reflections in prestack depth-migrated (PSDM) CIP gathers is used to determine adjustments in the velocity model to bring the subsequent version of the PSDM image into better focus. After one iteration of CIP tomography, the velocity model was smoothed and ready for input to the FWI process.

Next, the geophysicists started the FWI process, which, beginning with the initial earth model of velocities, iteratively models the observed seismic wavefield and adjusts the velocities in the earth model until there is an acceptable match between the modeled wavefield and the recorded wavefield. The observed wavefield was the upgoing P-wave wavefield that had been isolated at an early stage of processing from the broadband dataset. The criterion for convergence to an acceptable match between synthetic and observed wavefields is to minimize a misfit function that quantifies the difference between the modeled and measured data. To ensure that the FWI process converges on the global, or true, minimum rather than a localized minimum, the geophysicists conduct FWI in stages. First, they find an acceptable fit of the low-frequency wavefield. They then add and fit to successively

3 km [1.9 mi] long, spaced 75 m apart and towed at a constant depth of 18 m. After acquisition, the data were preconditioned and then simultaneously interpolated and deghosted using the GMP method. The upgoing pressure wavefield was then output on a 6.25-by-6.25 m grid for subsequent processing and imaging.\(^5\)

Initial inspection of the dataset showed it to be richer in high frequencies than in two conventional 3D seismic datasets and richer in low frequencies than in an earlier ocean bottom cable (OBC) survey. Both qualities are important for resolving subsurface geology and velocities through inversion of seismic data. High frequencies enable resolution of relative velocities between small stratigraphic and structural details. Low frequencies facilitate determination of absolute velocities, which are calibrated against borehole data.

The data underwent fast-track processing, using prestack time migration, which demonstrated the Heimdal member sands could be imaged more reliably using the broadband data than the earlier data.\(^2\) The operator’s geoscientists were able to establish the relationship between seismic reflectors and geologic horizons with improved confidence. Encouraged by these results, WesternGeco geophysicists applied FWI to the broadband dataset.\(^3\)

The starting point for FWI is a velocity model (Figure 11). The geophysicists began with a simple model, using seismic velocities interpreted from sonic logs from wells in the area of the Mariner field, which were then interpolated laterally between the wells along layers bounded by known geologic horizons. Based on previous processing studies, the overburden formations were assumed to be anisotropic; the P-wave anisotropy parameters epsilon (\(\varepsilon\)) and delta (\(\delta\)) were initially defined as linearly increasing from the seafloor to the base Cretaceous unconformity but were subsequently updated using a multiparameter inversion step in the FWI workflow.\(^7\)

15. Özbek et al, reference 5.
16. Migration is a seismic processing step in which reflections in seismic data are moved to their correct locations. Time migration locates reflections in two-way traveltime—from the surface to the reflector and back—as measured along the image ray. Depth migration locates reflectors in depth. Mathematically, migration is performed by various solutions to the wave equation that describe the passage of seismic waves through rock. Kirchhoff migration is a ray-based approximation founded on the integral solution to the wave equation derived by 19th-century German physicist Gustav Kirchhoff.


19. The base Cretaceous unconformity is the term applied to a strong seismic reflection surface that is mappable over much of the continental shelf in the North Sea. The reflector is an unconformity that is located close to the bottom of Cretaceous-age rocks and separates sediments deposited before rifting of the North Sea from sediments deposited after rifting.
21. Epsilon (\(\varepsilon\)) and delta (\(\delta\)) are P-wave parameters that describe vertical transverse isotropy. Epsilon is the P-wave anisotropy parameter and equal to half the ratio of the difference between the horizontal and vertical P-wave velocities squared divided by the vertical P-wave velocity squared. Delta is describes near-vertical P-wave velocity anisotropy and the difference between the vertical and small-offset moveout velocity of P-waves. For more on seismic anisotropy parameters: Thomsen L: "Weak Elastic Anisotropy," Geophysics 51, no. 10 (October 1986): 1954–1968.
25. Reference 16.
higher frequency bands until there is an acceptable fit of the full-frequency wavefield. This sequential FWI procedure stabilizes the inversion algorithm and ensures that the process converges to a global minimum.22

Application of FWI to the broadband dataset collected at Mariner field showed that a seismic dataset acquired using IsoMetrix technology can be inverted for a geologically relevant seismic velocity model that is capable of sharpening the focus of seismic images. After FWI processing, the velocity model was input into two prestack depth migration algorithms: a Kirchhoff depth migration (KDM) to compare directly against legacy data volumes and a high-frequency reverse time migration (RTM) performed directly in the natural shot domain after GMP.23 The velocity model from FWI sharpened the image of the control channel embedded into the overburden of the initial velocity model and highlighted additional channels (Figure 12).

**Figure 12.** Comparing models before and after full waveform inversion (FWI). Both seismic sections (left top and bottom) show the same geology to a depth of 1,200 m [3,940 ft] below sea level. The depth sections are the result of Kirchhoff depth migration (KDM); the sections are overlain by the velocity model (colors) that was used as input to KDM. The top section resulted from KDM using the initial velocity model. The control channel is in the top center and was given a higher velocity than its surroundings. The bottom section resulted after using the velocities output after completion of FWI. The control channel is in better focus, and the velocities of other channels are evident. The velocities of the overburden units have become more defined. The images on the right are depth slices at 158, 278 and 844 m [518, 912 and 2,770 ft] below sea level. Compared with the before FWI processing results, geologic features (yellow arrows) have become better defined after FWI processing.
The velocities in the shallow layers became more clearly defined. Below them, the reservoir zones of interest were less distorted. Cross sections through the KDM image volume showed that the velocities from FWI made a demonstrable difference in the focusing and positioning of overburden formations, while the RTM image volume gave the best resolution and signal-to-noise discrimination of Heimdal injectites against the background Lista shales (Figure 13).\(^\text{24}\)

The IsoMetrix marine isometric seismic technology and full waveform imaging are enabling and complementary technologies for increasing the qualitative and quantitative accuracy of seismic information. The IsoMetrix technology allows deghosting and interpolation of the recorded wavefield to produce unaliased seismic records. In turn, FWI provides geologically relevant velocities at scales that can be used to bring the overburden into focus. Together, these techniques enable geophysicists to image reservoir targets more clearly (Figure 14).

Advances in the sequence of steps from seismic data acquisition to final imaging are helping operators characterize the subsurface more distinctly. Measurements of the pressure wavefield and its gradients using IsoMetrix technology represent a significant development.

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The development of circle shooting, simultaneous firing of sources and full-azimuth source-receiver configurations embody advances in marine seismic survey geometry and design. Full waveform inversion, along with reverse time migration, is advancing geophysicists’ capability to develop data-driven velocity models. The converging improvements on all three fronts—acquisition, survey design and processing—provide the means for imaging complex geologic structures, forecasting drilling hazards and illuminating reservoir targets. —RCNH

Figure 14. Comparing images from ocean bottom cable (OBC) and IsoMetrix technologies. Both images are seismic depth sections to a depth of 1,700 m [5,600 ft] below sea level. They show the same geology extracted from datasets that have been processed using similar workflows through FWI and prestack depth migration; in each case, the color overlay is the P-wave velocity model that results after processing. For the 2008 OBC survey (left), the FWI processing was completed to a peak frequency of 10 Hz before migration using KDM. For the 2012 survey using IsoMetrix technology (right), the FWI processing was completed to a peak frequency of 5 Hz, followed by migration using high-resolution RTM. Despite some differences in the two workflows, both used a 2.5-Hz peak frequency for the first FWI updates. After processing, the velocity model result from IsoMetrix technology has the same, or better, resolution in the shallow overburden as the model result from the OBC survey.

Contributors

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An asterisk (*) denotes a mark of Schlumberger.