

Introduction to Duplex Wave Migration (DWM)

(Client's Guide)

Introduction

TetraSeis Inc. (TS) has developed a new type of pre-stack depth migration tool named *Duplex Wave Migration (DWM)* which received a USA patent in 2005. DWM is capable of imaging vertical and near vertical (90 degrees plus or minus 30 degrees) structures. This information is added to the information obtainable from conventional imaging tools to provide geologists with the total structural picture to define these much more structurally complex features.

Conventional seismic imaging tools are capable of delineating moderate folding in which the reservoir cap rock has dips range from 0 to 45 degrees to form dome shaped closures that trap hydrocarbons. Many of these reservoirs have already been found, however, more structurally complex reservoirs that involve traps against near vertical faulting have yet to be found. Those play types can contain very large trapping systems; despite this many have not been explored because conventional seismic imaging methods are not capable of delineating these structures.

DWM technology allows reliably locating the vertical structures. Drilling for these targets is extremely risky and has largely been avoided in the past. With DWM technology, the geologist is given direct evidence of the actual size and location of these near vertical structures and therefore the risk associated with the selection of the drilling location is significantly reduced.

Several major oil companies have completed and published extensive studies that compared the accuracy and effectiveness of DWM technology to other currently available fracture detection methods that have illustrated the superior performance of this new technology. In some cases a direct and predictable relationship was proven to exist between the amplitudes observed on the DWM data cubes and the production rates (permeability) at the historic and recently drilled well bore locations. Those results confirm that Duplex Wave Migration is:

- ✓ ... a proven technology and the most precise method in *obtaining direct images of sub-vertical boundaries including fracture zones, faults, the walls of salt domes, etc.*
- ✓ Capable of *direct measurement of relative lateral heterogeneity* (change in acoustic impedance)
- ✓ Kirchhoff implementation *allows application on any land irregular geometry*
- ✓ Permitting to *focus on specific sub-vertical faults or fracture systems*
- ✓ Identifying of plays with *zero throw faulting*
- ✓ Determining *reservoir plumbing*
- ✓ Providing evidence of potentially highly productive reservoirs and significantly reduces the risk associated with drilling.

Part of *TetraSeis' (TS)* activity is *execution of projects of seismic data processing and interpretation using DWM*. Usually such project also include following geological interpretation of processing results. *Beginning from 2004 this technology is used for 2D and 3D seismic data processing* and has multiple examples of its successful application at solving of variety of geological tasks for different seismic survey conditions.

The following products are included in the DWM technology deliverables:

1. A depth domain DWM data cube that contains images of the vertical and near vertical geologic boundaries.
2. Post DWM processing services that are designed to extract and enhance the vertical boundaries and reduce seismic acquisition related 3D footprint noise
3. Horizon depth slices that illustrate the spatial location and classification of the fault and fracture systems which are tied with any available well log information.

The *service consists* of a) DWM data processing, b) Post-processing of DWM data cubes, and c) interpretation of faults and fracture systems identified by the DWM technology.

TS head office is located in Calgary, Alberta Canada where are also located its cluster computing capabilities for the provision of DWM services. *TS is also doing essential R&D in the Ukraine.* Client Oil and gas companies can also choose to obtain “in country” DWM processing services.

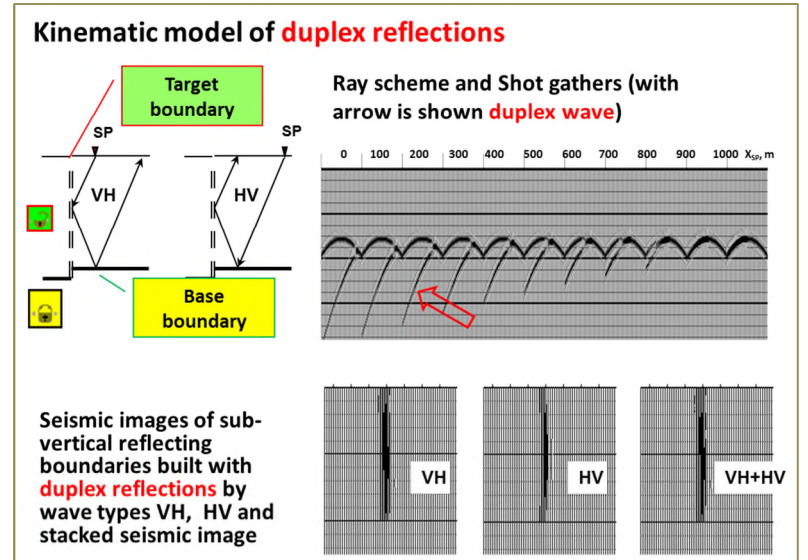
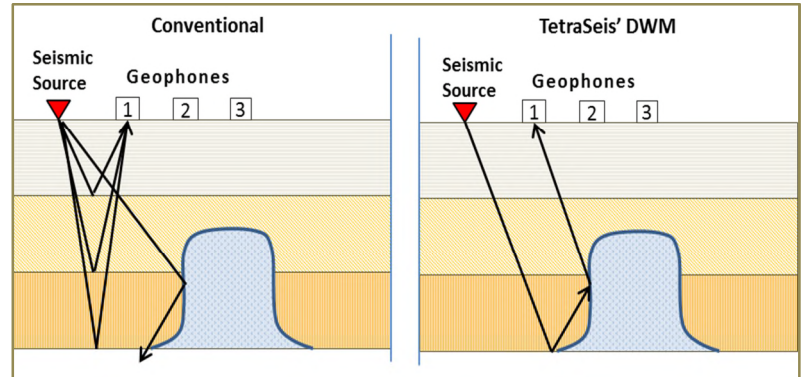
The price for DWM processing services is calculated basing on the current pricelist in \$US/sq.km rate and is comparable with such for the high-quality PSDM. The rate depends on the size of the survey area assuming conditions of the conventional 3D survey. For particular project, if there are consistent differences from the conventional conditions, the price may also depend on the volume of the source data (density of seismic survey), number of target horizons, and other specific conditions. Same can be related to *in-depth (full scale) geological interpretation* as a part of DWM service project.

- ✓ It is well known that the time (for completing the project) and (internal) cost are not linear function of the processing area for the separate (seismic data processing and post-processing) project. It means a project for survey and geology with own seismic-geological particulars, which require separate QC, preparation, processing and post-processing tuning. It can be estimated that separate project for:
 - 50 km² approximately takes 1-1.5 month (50 - 33 km²/month)
 - 200 km² – 2-3 months; (100 - 66 km²/month)
 - 500 km² – 3-4 months; (165 – 125 km²/month)
 - 1,000 km² – 4-5 months; (250 – 200 km²/month)
 - 2,000 km² – 5-6 months; (400 – 333 km²/month)
- ✓ It is assumed that *TS* get from the client conditioned for DWM data such as input gathers and interval Velocity model so we can concentrate mainly on DWM job.
- ✓ Each project requires not only computer calculation time but a human time as well because we need to QC input data to make sure that all data are acceptable for processing; job monitoring, in case job bombed out; client communication on a regular basis; post-processing if needed and writing reports.

Background

Conventional Kirchhoff PSDM schemes assume that the kinematics of the ray path travel time calculations are such that the seismic energy bounces off of one and only one reflector before returning to the surface. TS's Kirchhoff type implementation of DWM assumes that the seismic energy undergoes two bounces off of primary reflectors during its wave front travel path before it returns to the surface. This secondary bounce energy appears (on a raw seismic record) to be some form of coherent noise, or offline artifact on the seismic record. Consequently it is stacked out when conventional imaging criteria are used.

However, if we re-define the kinematics of the problem we can stack (or image) the data in such a way that this duplex wave energy (DWE) is re-enforced and the conventional single bounce energy is stacked out. When we impose this re-definition of the basic kinematics of the migration process on the seismic data the resulting 3D data cube contains vertical, or near vertical boundary information only. Therefore, through the use of DWM we can fill in the very information (dips from 60 to 90 degrees) that is missing from convention prestack depth migration results.



Applications

The imaging of vertical boundaries has become extremely important for solving a whole host of exploration and production challenges as follows:

- Salt wall topography imaging.
- Zero or near zero throw faults.
- Delineation of fault compartmentalization within the reservoir.
- Fracture system delineation.
- Fracture system permeability characterization through detailed well production tying and water interference tests.
- Locating structurally controlled diagenetic reservoirs formed by basinal hydrothermal fluid flow along vertical faults as in hydrothermal dolomite (HTD) plays.
- Discriminating between HTD geo-bodies that have hydrocarbon filled porosity verses none hydrocarbon filled dolomite using relative amplitudes and AVA analysis of vertical geo-bodies.
- Identification of bypassed reserves - enhanced oil recovery (EOR)
- Delineation of the edge boundaries of oil (or gas) to water interfaces.
- Delineate complex faulting patterns in coal bed methane plays.

- Check reservoir seals for unknown faults – critical for top seal analysis in CO2 sequestration.

Most applications (2008-2013) DWM found at imaging conventional (clastic and carbonate) and unconventional (particularly fractured basement, shales, and tight gas) fault and fracture zones of different types: compactional, regional, fractured corridors, fractal, en echelon, etc. Several presentations and papers demonstrating the use of DWM are available at company’s website www.tetraseis.com.

Comparisons of DWM with Other relating Methods

Reverse Time Migration (RTM) vs. Duplex Wave Migration (DWM)

RTM	DWM
Reverse Time Migration (RTM) can be used in the PSDM run and theoretically it will image the duplex wave energy because it can image primary energy plus all types of bounces.	DWM is a tool directed to image sub-vertical boundaries. Kirchhoff DWM can be configured to view vertical geo-body amplitude responses as a function of angle of incidence thereby providing an AVA analysis capability on the vertical geo-bodies which is not possible using conventional imaging technologies. Kirchhoff DWM is much less compute intensive than RTM.
RTM does not attenuate the single bounce (primary) energy which is about 100 times stronger than the DWE, therefore, it is likely that the information we are attempting to image will become lost in the primary energy.	The DWM process strongly attenuates the primary energy and sums or images the DWE thereby exposing the vertical geo-body images. Kirchhoff DWM can be configured to split the DWM views into various types of duplex waves such as DWE that bounces of the vertical boundary first and the horizontal boundary second and vice versa, whereas, this type of wave field separation is not possible using RTM. This additional flexibility provides opportunities for detailed analysis of selected fault/fracture boundaries.
RTM does not attenuate the inter-bed multiple energy. This information remains in the conventional PSDM to confuse the interpretation.	The kinematics of inter-bed multiples are very similar to that of primaries and therefore the DWM process will also strongly attenuate the inter-bed multiple energy thereby revealing a less confusing image of the vertical fault/fracture systems.

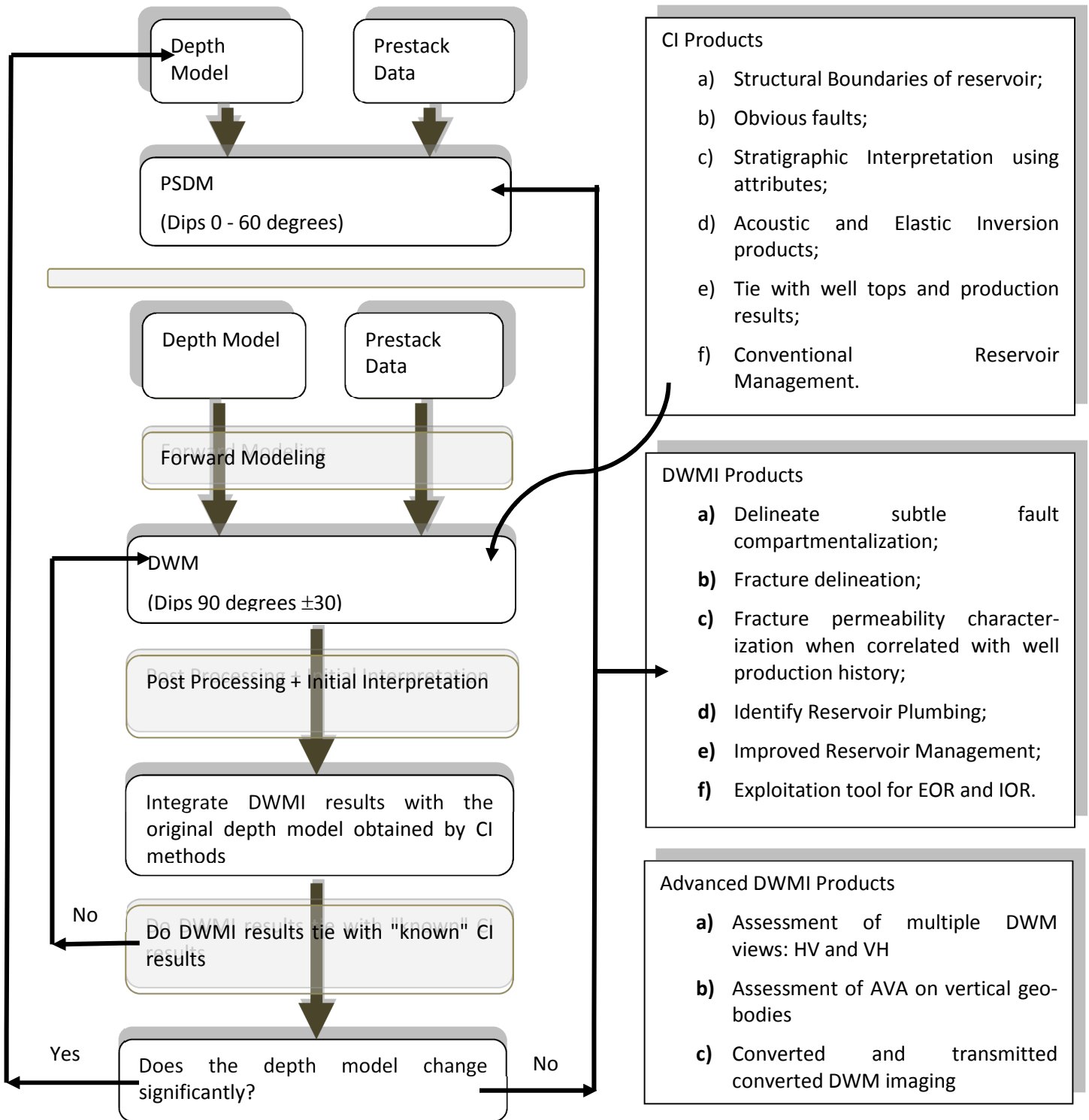
Other Methods and DWM

Method	Requirements to Work	Capabilities
Coherency and Curvature (indirect detection)	Structural deformity – none zero throw of fault	Conventional fault and channel detection
Spectral Decomposition	Spatial variation of wave field filtering caused by hydrocarbons in fractured systems.	Can be confused by changing thin bed thickness.
Azimuthal analysis: velocity and amplitude as function of azimuth	Needs azimuthal fracture alignment and wide azimuth acquisition.	Only works if restricted conditions met. Implication: Low horizontal resolution.
Paradigm Migration 360	Is based on the Kirchhoff integral and operates mirrored and diffracted waves. The latter are ones that form the basis for indirect delineation of faults.	Duplex waves are usually much stronger than the diffracted ones and for migrations based on the Kirchhoff integral, including migration 360 are considered as noise.

Duplex Wave Migration (Direct Detection of fracture systems)	Measurable lateral changes in acoustic impedance. Requires Base Boundary as input data	Kirchhoff implementation allows application on any land irregular geometry. Direct measurement of relative lateral heterogeneity (change in acoustic impedance) High lateral resolution and AVA capabilities.
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DWM processing and interpretation and the conventional interpretive workflow

Figure 1 illustrates where DWM fits within the processing and interpretation workflow. DWM is a new type of depth migration that is run after conventional PSDM has been used to enhance the quality and detail of the Conventional Interpretation (**CI**). A list of products that we routinely obtain from the CI workflow is shown in figure 1. DWM uses exactly the same input data and depth model, plus the location of a deeper mirror event, called the base boundary, to provide critical information about vertical boundaries or lateral heterogeneities within the reservoir. The products of the Duplex Wave Migration Interpretation (**DWMI**) are shown in figure 1.



Flowchart 1: Integration of the CI and DWMI Workflows

Conventional Interpretation (CI) after PSDM : Provides clear structural boundaries of the reservoir and some information about obvious (non-zero throw) faults.

Duplex Wave Migration Interpretation (DWMI) : Provides detailed information about the subtle zero-throw faulting and fracture systems within the reservoir. The interpretation of the DWM results should be performed within the context of the information obtained from the CI workflow. If the CI results do not tie with DWMI results then further DWM analysis or post processing is needed to determine which interpretation ties the geology and production results the best.

Goals and Requirements

DWM outputs a data cube in depth that contains only vertical or near vertical events. This is achieved by imaging duplex wave energy which has bounced once off the vertical boundary and once off a deeper event called the *base boundary*. DWM is a direct detection technique that relies on imaging a reflection from the vertical boundary; therefore the vertical boundary must exhibit an acoustic impedance change. The DWM data cube represents a 3D that defines relative lateral changes in acoustic impedance. This is a direct detection method to define various types of vertical boundaries or lateral heterogeneities that are associated with the eleven exploration problems listed above.

The *base boundary* must be below the deepest limit of the vertical boundary to be imaged and it should be a reasonably contiguous and strong reflector. The user must provide the program with the depth model used for PSDM and the surface in depth of the desired event to use as the base boundary. The base boundary need not be flat or gently dipping in nature but this does help to enable the accurate definition of the base boundary in depth.

The input data is the same input gathers that were used for PSTM and PSDM. If noise attenuation has been applied it should be discussed with TS to ensure that the DWE has not been attenuated. Multi-channel filtering techniques such as FK filtering in the shot domain or tight RADON filtering in the CDP domain will attenuate the DWE which appears on the shot record as coherent energy at odd angles and dips. Procedures of shot records interpolation used in conventional data pre-processing may also attenuate DWE. Generally speaking, coherent noise attenuation does not need to be performed before DWM because the DWM process itself automatically attenuates any energy that does not have the kinematics of DWE.

Specific evaluation of each project for DWM applicability

TS will review cross sections and processing flows to determine the applicability of each project for the DWM process. During data QC as preparation for DWM processing, TS provides report about steps which should be removed from the data pre-processing. We also need to understand the nature of the geologic and interpretive problem that remains to be solved after the CI process has been completed. DWM is a new technology that TS is in the process of introducing to a naturally skeptical industry and we wish to only accept projects that we feel do have a good chance of success. TS will provide a summary report of strengths and weaknesses of each data set for DWM applicability as part of the bidding process.

Input Data and Pre-processing requirements

1. Input Seismic Data: The input data can be sorted in common shot gathers or in CDP gathers. The trace headers should contain the source and receiver coordinates. These coordinates should be consistent with the corresponding coordinates of the velocity-depth model and the base boundary horizon in depth. When DWM migration is to be performed from true surface the trace headers should contain the elevation of the sources and receives.
2. Requirement for any pre-processing steps: As a general rule, the input data to DWM is the same as for other common migration procedures. In order to obtain high resolution fault mapping, PSTM and PSDM require the preservation of, as much as possible, any diffracted energy (originated by faulting) present in the data during the pre-processing steps. DWM has the same requirements since the kinematics of the duplex waves is very close the kinematics of diffracted waves. In other words, DWM does not add any extra requirements from pre-processing.

Generally, in order to bid on this service we would need to ask you to provide us following:

1. Cube (cubes) of source seismic records (SEG-Y format):
 - a. with entered static corrections;
 - b. with entered muting;

- c. in variant without applied frequency and spatial filtration and with variant of such (or other) filtration, which is optimal by client's opinion; Usually it corresponds to state of readiness for (pre-stack) depth migration;
2. Interval velocity model (cube in SEG-Y format) of survey object, with which was realized last version of depth migration;
3. Cubes of anisotropy parameters in SEG-Y format if applicable;
4. Geometry of surfaces of base (target) boundaries (text files or in other popular formats), for studying of interval over those base boundaries which represent interest in relation to sub-vertical faults, compact fracturing zones, etc;
5. Cube (cubes) of conventional 3D depth migration; Reference PSDM cube which has been calculated using the same seismic gathers, interval velocities and parameters of anisotropy;

Additional Client's information for DWM post-processing and interpretation:

1. Relevant and up-to-date structural-tectonic map of the study object with:
2. Layout of existing wells with production history;
 - a. Well data - strata tops etc (tabular txt form or in other popular formats); Wells location and description such as inclinometry and etc;
 - b. Well data - sonic well-logging (LAS files); Wells logs;
 - c. Well data - table of coordinates of node points : heel, borehole bottom etc;
3. Comments of customer to provided data and specification of main targets for processing with DWM;

Quotes for providing Processing and Interpreting service: to provide this service we would need to know the particulars of seismic data and geological task.

QC steps does TS follow upon receiving the data

The first step is the loading the input 3D seismic data and base boundary horizon information in preparation for the DWM runs. During this process we will check that the base boundary events do correspond correctly with the images as seen on both the input data and the PSDM data cubes and the associated velocity model. Also, we need to ensure that the actual surface elevation, the statics applied, and the processing datum information are well understood so that when the Tetrale DWM process computes it's travel times tables it is referencing the data correctly. This process needs to be done with a great deal of care to make sure that some sort of basic datum referencing error does not contaminate the results. This process will involve applying a basic NMO and stack process to check the input data and other tests such as targeted Kirchhoff PSDM as deemed necessary to ensure that the 3D data has been properly prepped for the DWM process.

Algorithmic Variations depending on Geologic Complexity

1. ***Time domain DWM:*** this type of migration is used for *express estimation of applicability and effectiveness of DWM in conditions of small lateral velocity variations*. The same stacking velocity field that is used for pre-stack time migration can be used as input velocity for time DWM. This file is provided in a text format.
2. ***Depth Domain DWM:*** this *basic type of migration may be used even in conditions of strong lateral velocity variations*. The same depth velocity model used in PSDM is used as input velocity for depth DWM. This file should be provided in SEG-Y format.
3. ***Depth Domain DWM for a TS medium:*** this *advanced type of migration is used when the imaging of a sub-vertical object is strongly influenced by TS anisotropy*. The following cubes of data are used as input

data: depth velocity model, the slope of the axis of symmetry for a TS anisotropy, Thompson parameters ϵ and δ . These cubes should be in SEG-Y format. Additionally, a depth map of the base layer preferably tied to well data should be provided in a text format.

4. **Depth DWM of converted waves:** duplex reflected converted waves sometimes are stronger than compression reflected waves. In those cases we have the opportunity to use their energy. In order to *additionally perform a DWM variant on converted waves which needs to input the V_p and V_s depth velocity models*. Additionally, a depth map of the base layer preferably tied to well data should be provided in a text format.
5. **Depth DWM of Scattered waves (DSWM):** in difference from the DWM basic variant it does not require determining of the base boundary. The DWM images summation is done for determined depth interval. The results produced usually contain images of boundaries without limitation on dipping angle (both sub-horizontal to sub-vertical including intermediate dipping angles). It usually requires more computations, but in many cases produces more complete results for solving the required geological task.

How accurate does the depth model have to be?

Since the CI process has already been completed it is assumed that an accurate depth model is available. TetraSeis will attempt to verify the depth model accuracy with our tests but if the model is shown to not be accurate the client must provide an updated model. As with any other type of pre-stack depth migration, errors in the depth model may produce errors in the lateral placement of the vertical boundaries. It should be remembered that we can also use different views of the same object in depth using data bouncing off it from different directions to verify the velocity model. In other words, this ability to use the criteria of common spatial location as an indication of correctness of the depth model may enable us to improve our estimation of the anisotropic parameters.

The requirements for accuracy of the depth model are no greater than the requirements for conventional PSDM. The depth model should be tied with the well tops as would normally be the case during the CI process.

The “interpretive problem” to be solved

Prior to performing the DWM processing and interpretive workflow the client will have gone through the Conventional Interpretation (CI) process. Figure 1 illustrates the standard list of products that are obtained from the CI process. As is often the case this process does not provide sufficient information for risk reduction especially if the exploitation problem requires the delineation of zero throw faults and/or fracture systems. CI has traditionally been focused on obtaining accurate information about the upper and lower boundaries of the reservoir, or locations of pinch outs, lithologic changes, etc. Several conventional methodologies for fracture delineation have been developed such as coherency cubes, curvature attributes, spectral decomposition and azimuthal variation of velocities and amplitudes. All of these methods have had limited levels of success in the case that the fault/fracture system does not have any expression on the shape of the reservoir boundaries. They can sometimes indicate that fracturing is likely but they fail to precisely locate and delineate the fracture pattern. Modern EOR risk reduction requirements necessitate that we find a way to more precisely define these fracture system. The DWM processing and interpretation (DWTI) process is designed to accomplish exactly this goal.

The DWTI results are meant to complement and complete the CI results. Therefore to begin this process effectively we need to start with a clear understanding of the results achieved via the CI methodology so that we can clearly define the areas of remaining information deficiency that are required to reduce the exploitation drilling risks to acceptable levels. This means we must understand how well and/or poorly the CI methodology predicted productivity levels so that we can effectively target the missing information. Ideally we would have available to us the well production results before beginning the DWTI process. However, it is well understood that many companies prefer to see a “blind test” first before revealing this

information to a contractor that claims to have a new technology. In this case we can begin the process by producing a “raw” DWM data cube to illustrate the fact that real addition information is likely to be obtained by the DWMI process. After the initial level of acceptance is achieved the full value of the DWMI process can be obtained by illustrating how clearly the DWMI results are consistent with the production results.

The products we should expect to obtain from the DWMI process and the Advanced DWMI process are listed in figure 1. This tool and the general methodology has proven to be very effective for dramatically improving the ability to understand the flow barriers within the reservoir and therefore to substantially reduce the risk associated with the exploitation drilling program.

Using of Seismic Modeling in the workflow

In *Flowchart 1* we see that the forward modeling step is outlined in a dashed box. This means that it is optional; however, in some cases it may be highly advisable.

TS has a full suite of seismic modeling tools that enable us to compute very realistic 2-2.5-3D-3C shot records given a defined field recording geometry and a given depth model. We suggest that for the 2D forward modeling process we select a line in the dip direction through the model and we utilize the same shooting geometry that mimics the actual 2D data that has been shot in this area. We can produce the shot records for one full line and then process this data through to a full set of DWM products. The forward modeling work can proceed on a separate and simultaneous workflow while others are preparing the real data for the actual DWM process. The specific benefits of running forward modeling are as follows:

1. TTG will assist the interpreter to inspect the shot records to identify the strength and characteristics of the DWE.
2. A noise attenuation test can be run on these data to evaluate whether or not the DWE has been harmed by a previous noise attenuation process.
3. We can evaluate the ability of PSTM, PSDM, and DWM to image the reservoir features of interest. This will enable us to establish which technologies are needed to delineate the reservoir characteristics sufficiently to reduce the drilling risk to an acceptable level.
4. In the 2D case we can evaluate the ability to image the same set of vertical reflectors from both sides of the boundary. We can also evaluate the sensitivity of these images to errors in the velocity model – that is, if the velocity model is in error the same events will not line up in the same location in space. This is an entirely new methodology for testing the accuracy of the velocity model used for depth imaging.
5. We can evaluate the effectiveness of each of several potential events to image the vertical boundaries. Using this information the interpreter can make the final decision which event or events to utilize as the base boundary.
6. The DWM response of a single trace can be used to help define aperture and other parameters for the DWM process.
7. If it turns out that the forward modeling process indicates that DWM is not likely to work in this area then the client may elect to terminate the project thereby reducing the cost of testing the DWM process. In this regard, it needs to be remembered that 3D DWM is inherently much more powerful as an imaging process than 2D DWM so this would need to be considered.

General description of the types of DWM parameter tests

Various DWM parameters such as apertures will be tested. Assessments of the two main observation schemes, Horizontal to Vertical (HV) and Vertical to Horizontal (VH), and the summed (HV + VH) DWM data cubes will be made. The initial set of tests will be run using a base boundary as selected by the client. After

the basic parameters have been determined the client can choose to test additional base boundary runs at additional costs.

Evaluation of the “raw” DWM and the client role

After the first “raw” DWM data cube is produced the client will be brought into a collaborative workflow with TTG. The DWE we are using to image the vertical boundaries is quite weak and depending on the shooting parameters and depths we sometimes have issues with 3D footprint or other migration artifacts. At this point we do an initial interpretation of the raw DWM data cube and attempt to identify what events are real versus being an artifact of some sort. This is where the known information that was obtained during the CI process can be used to perhaps modify the DWM parameters to prepare for a second run of the process.

Using CI generated information at the DWMI stage

DWM is a high level imaging tool that is attempting to delineate information about vertical geo-bodies. As with any subtle imaging process, the more we can constrain the process from including confusing and erroneous information, the more reliable the final DWMI product will be.

The main objectives for DWM are vertical heterogeneities of carbonate and terrigenous collectors. In each specific case, these sub-vertical boundaries can be represented by the boundaries of geological blocks, such as the flanks of salt domes, reef flanks, faults including small amplitude faults or fracture zones. The existence of apriori information from previous works enables us to classify these sub-vertical boundaries.

First example: If we have to differentiate a fracture zone that may correspond to a hydrocarbon reservoir from a non-trap zone, it is necessary to compare the obtained data from DWM with the results of fault delineation obtained from standard structural interpretation. In those cases where these data match each other, there is a very small probability for this matching zone to be a trap. These zones, usually, do not have sealed caps that trap deposits. There is a good probability of fluid filled high permeability reservoirs when faults or fracture systems are seen only in the results from DWM.

In many cases the existing well production history (apriori information) can confirm the correlation of these zones of high fault/fracture permeability with the DWMI results. Well log anomalies and well interference test results can be shown to more readily correlate with the DWMI than the CI results. Therefore, a greater level of confidence in our ability to predict productivity rates in areas away from the wells can be achieved.

Second example: A case history published by Lukoil presents a fault system that disrupted the unit overlaying the main reservoir. The standard interpretation of this system provided the identification of a system of fractured zones within the reservoir, their direction and genesis. These fracture zones were the roots of the downward attenuating faulting system. The results of DWM may be used to control and verify any previous CI results since any high-amplitude faults detected by standard interpretation should also be detected by DWM.

The availability of apriori information about the acoustic properties of the base boundary layer allows the calculation of its AVA effect, which can be used to evaluate the properties and the AVA effect of the target vertical object.

The lack of apriori information erodes the level of confidence that can be attributed to the final DWMI results. For example, the lack of information about the orientation of the main faults can lead to an erroneous interpretation due to strong 3D footprint noise contamination. Information about the orientation of the main faults can generally be obtained with confidence from the CI process. Within this framework we can obtain detailed information about the more subtle fracture system during the DWMI process.

In order to be confident in the duplex wave interpretation, it is a must to have information related to the well performance for at least two wells: the best and the worst wells in the oilfield with a full set of

borehole fracture studies. This is required when discriminating between high-frequency hindrances and consistent DWM lineaments, in order to determine the noise level relative to the signal.

The DWTI processing to improve the CI results

The Kirchhoff implementation of the DWTI process is extremely versatile. It allows us to look at the data in a whole new way with several different sets of views to verify the images. Also, we are using energy on the conventionally recorded shot record which the CI process by definition attenuates and throws away. This fact provides a type of secondary verification of some of the information interpreted in the CI process. For example, all of the faults that have been previously identified should be verifiable during the DWTI process.

In figure 1, after the initial DWTI is complete the question is asked “does the depth model change significantly. If the answer to this question is “Yes”, then it may be necessary to repeat the conventional PSDM run. In particular, it is our belief that DWTI has the potential to improve the estimation of anisotropic parameters in the depth model which can greatly affect the quality of the PSDM image.

Post DWTI processing procedures enabling better DWTI results

Please, see *Post-Processing Manual for DWTI -Interpreter's Guide-* on company's website.

Integrating the DWTI results with the CI results

The results of the DWTI interpretive process provide us with independent maps to which additional information from well logs and conventional interpretation can be added. Well log data provides fracture orientation measured by XMAC and FMI that can be illustrated as an arrow on the map. Also, well data provides the average value of productivity before and after stimulation, and the fracture density value by core/FMI; however, this information is less useful due to the measurement conditions and the inability to confidently differentiate between open and closed fractures.

CI products such as the contour map of the top and bottom of the reservoir, fault delineation from standard time or depth sections, the delineation of lithologic boundaries – reef flanks, canyons, channels, barriers, and the oil-water contact are all useful information that may be verified or updated as a result of the DWTI process.

Correlating the DWTI results with the well production data to enable classification by permeability of the fracture systems

The first step in the classification/ranking of the DWTI anomalies is the identification of fault systems that have non zero throw such that they can be identified during the CI process. These fault systems should be well delineated with tools such as coherency cube analysis and they should manifest themselves as very bright events on the DWTI data cube.

The DWTI process will delineate these fault and fracture systems and the next level of discrimination is to identify which of these systems act as conductors of fluid and which act as a seal to the flow of fluids. The main difference between the conducting fracture zones and the healed fracture zones lies in the number of conjugate phases that are observed on the DWTI data cube. It has been demonstrated, empirically, that if the seismic anomaly is represented by two or more conjugated positive and negative phases, then it is an open fracture zone. If one phase exists on the map separately and independently by itself then, most likely, it is either a healed vertical boundary or a very thin fracture zone.

The third step of ranking is based on the well log data. To start, a graph can be plotted by comparing the amplitude values of the duplex waves with the production values of the well. If a linear dependency is easily achieved by virtue of using a significant number of statistical samples and/or by virtue of quality measurements of hydrodynamic parameters, then the ranking can be done based only on this graph. If the number of available wells is not enough and the quality measurements of pressure on them are even

smaller than the ranking can be done only on a qualitative level and the number of ranks cannot exceed the number of participating wells.

Identifying Permeability basing on DWM results

1. Porosity cannot be obtained immediately from the amplitude of reflected waves. This is achieved only by using impedance values (since the amplitude of the reflected waves represents the properties of the interface and the impedance represents the layer properties). Therefore to obtain the properties of the target zone s it is will be necessary to do a quantitative evaluation of its properties. The complex of additional work may be required, including reservoir engineering modeling.
2. A well parameter of permeability can be used to calibrate DWM results at stage of extensive geological interpretation. Thus it must be taken into account that:
 - a. Permeability measured directly from the core sample relates to the micro-fractures and it does not have direct relation to the large-scale observed seismic fracture zone permeability.
 - b. Usually cores are not collected from these types of zones and even if it is done, just pieces are collected. The measurement equipment is usually built in such a way that it works on an entire core sample; therefore these tools measure the permeability of the matrix and the micro-fractures.
 - c. The permeability that surrounds the well bore is the permeability is calculated basing on the reservoir model. Equations used at such computations, besides from formation pressure measurements, include. the fluid viscosity, and most importantly, the thickness of the effective interval, which is the less determined parameter when dealing with conducting corridor studies.
 - d. Estimations of effective width diverge from a few meters (in some cases, by using well data) up to one hundred meters (by geo-modelling and commonly used geological concepts).
 - e. It should be noticed that effective width parameter is used in the denominator of the mentioned above reservoir modeling equation(s). Therefore, if divide the pressure difference based on thickness estimate of a few meters, you will get a permeability value that is several times larger than if you divide the pressure difference based on estimates of thickness of one hundred meters. Because of this, it is more correct to calibrate seismic by using the productivity index, since its formula only has two parameters and both are measured: flow rate and pressure.
 - f. Also, there are a few issues to be aware of because a fractured reservoir is very uncertain in its behaviour. In high pressure conditions the fractures can collapse and the flow rate value can change a lot depending on the current mode. The best way is to orientate one's self is not on one value but on the average value and subtract it from the Inflow Performance Relationship curve.

TS's Computing and Data Management system

TS has a cluster computing system in Calgary, Alberta, Canada. This system has the following capabilities available to the client and all employees of TS:

1. All of TS's forward modeling and DWM imaging technologies.
2. Highly secured Internet access using given usernames and passwords.
3. A high end 3D interpretation and visualization package that is supported by graphical display accelerators so that the user with limited Internet speed access capabilities anywhere in the world can view the results easily.
4. Interactive collaborative sessions between TS personnel and our clients anywhere in the world at any time as necessary 24 X 7.
5. Fully secured, FTP up-load and download capabilities for easy transfer of data sets.