Rock physics driven inversion: the importance of workflow

Michel Kemper proposes a reservoir characterization workflow that spans modelling, processing, and quantitative interpretation within a rock physics driven framework (not a mere attribute algorithm) and provides a practical guide with some pitfalls to avoid.

Seismic inversion is the process of converting seismic reflectivity data to rock property information ranging from band-limited acoustic impedance (simplest) to petrophysical properties such as Vshale, porosity, and water saturation (most complex). From this definition it would appear that well data is not used; in practice, well data is used extensively in the inversion process, and this will be detailed in this paper, which consists of three parts:

- It is important to ensure that both seismic and well data are optimally conditioned prior to the inversion process, and some typical techniques will be shown.
- A rock physics study illustrates the need to (a) determine what the end product of an inversion project should be (bearing in mind the objective of this study), and (b) whether it is feasible to achieve this with the data available (noise, resolution, etc).
- A wide selection of inversion algorithms will be split into various categories and discussed in some detail.

Lastly, inversion is a tool, and not an end in itself. It can be used to good effect in reservoir characterization (from exploration to reservoir monitoring), and in this paper some techniques will be listed. A full discussion is outside the scope of this article. In practice the above workflow is not linear, and some iteration is required. Some examples will be shown in the text.

Data conditioning

Conditioning of seismic data:

Seismic data, typically pre-stack migrated, is generally processed for optimal structural imaging, and not necessarily for uses such as seismic inversion. In an ideal world the processing gives a best possible image *and* is 'inversion ready'; in practice, there may be a phase shift or some residual NMO/misalignment in the data to correct for prior to inversion. Here some recommended seismic data conditioning (SDC) steps are listed, in typical order.

Seismic data to be inverted either depends on incidence angle or is a seismic dataset derived from angle-dependent seismic, e.g., intercept and gradient datasets. So without loss of generality, it may be stated that either of the following datasets is always inverted:

- Angle gathers (NMO corrected offset gathers converted to angles, after perhaps some other operations)
- Partial angle stacks (in this full stacks are included, where all traces rather than a partial number of traces are stacked)

Experimentation has shown that inverting partial angle stacks (partial stacks for short) gives results of comparable quality to inverting angle gathers, provided the angle gathers and then the partial stacks have been derived with care. Whereas the advantage of angle gathers is obvious (more data to constrain the inversion), partial stacks have a higher signal to noise ratio due to stacking and allow estimation of wavelets per partial stack that can be used to perform specific and important SDC operations. The pros and cons even out approximately, which is why nowadays seismic contractors provide both offset gathers and partial stacks. Here the focus is on inversion of partial stacks. However, partial stacks will have to be re-derived from gathers if the partial stacks are of insufficient quality and cannot be 'repaired' by SDC. Therefore some steps are presented first to (re-)derive partial stacks from offset gathers.

Deriving partial angle stacks from offset gathers

1. Radon transforms: To remove multiples, if present in the data.
2. Residual move-out corrections: These can be applied over several horizons, producing shift values for stretching and squeezing target traces to match arrival times from a reference stack.
3. Offset to angle conversion: A velocity field is required for this conversion, calibrated to well velocity profiles (e.g., krige the well velocity profiles collocated by seismic velocities). The quality of the stacking or migration velocities is crucial, as otherwise there is a lot of detrimental 'smearing'. See Fig. 1 for an example.
4. Muting: Although this is a relatively simple process in principle, where precisely to inner and/or outer mute the data depends on the two way time, the velocity field and the rock properties, and thus changes from trace to trace. It

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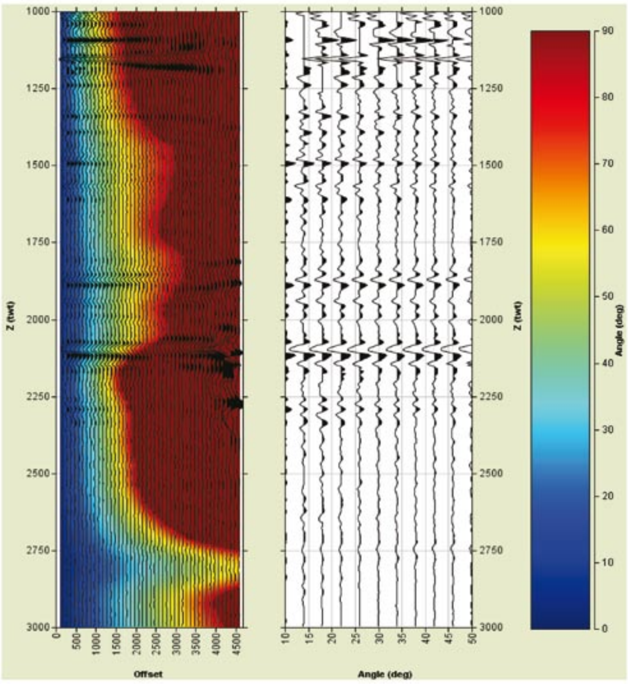

***Figure 1** Offset gather and angle field (against colourbar) obtained from a velocity profile (left) and resulting angle gather (right).*

is best to digitize the mutes on a number of trace positions (including at the wells, where synthetic angle gathers can be used to guide the muting), and then to use some form of interpolation to obtain a mute field, which is then used to do the actual muting.

5. Partial Stacking: In its simplest case this is just the mean over a number of traces falling within a user specified angle ranges of 7–10º. There are however more advanced techniques that can add some quality to the stacking process (see for instance Liu et al., 2009).

Now the focus can shift to the SDC of (possibly re-derived) partial stacks

Seismic data conditioning of partial angle stacks

Note that before SDC is performed on partial stacks the corresponding wavelets are estimated by comparing, at the wells, the partial stacks with spike series calculated using the partial stack incidence angle (White, 1980). These wavelets will be used to good effect in the partial stack SDC.

1. Zero-phase stacks: Two approaches are possible and can be experimented with to determine the best one – phase rotate each trace by the residual phase as determined by the corresponding wavelet, or first balance the phase of all traces to a single reference trace and then phase rotate all traces by the residual phase of the wavelet corresponding to the reference trace.
2. Spectral and amplitude balancing: A spectral balancing tool ensures that the frequency character (spectrum) of all traces will match the frequency character of a reference trace and can be achieved, for example, by a deterministic amplitude cosine based balancing method (Roy et al., 2005). Amplitude balancing is performed by using RMS amplitude values extracted over a gate of which the AVO characteristics are known and constant (Ross and Beale, 1994). Fig. 2 shows an SDC improvement largely due to amplitude balancing.
3. Phase and time balancing: A joint phase and time shift balance operator can be computed within a time gate and applied to restore target traces to a reference trace. Maps of these functions should be displayed as a QC and edited before conditioning the target traces (Fig. 3).
4. Residual move-out corrections: A range of correlation based methods are available to remove residual move-out problems. These are applied on a single horizon, producing shift maps which can be QC'd and edited before application, or over several horizons, producing shift values for stretching and squeezing target traces to match arrival times from a reference trace.

Fig. 4 shows an example where most SDC steps have been applied. There are of course other general operations such as filtering (edge preserving, structurally oriented), multiplication by a constant (multiply by -1 to flip the phase, for instance), which will not be discussed further.

Quality control is critical in obtaining an optimally conditioned set of partial stacks for inversion. A key QC tool is the use of maps to display intermediate products from the SDC workflow, such as semblance, time shifts, instantaneous frequencies, etc. In some cases it is necessary to edit/smooth these maps (especially the time shift map!), after which they can be used in the appropriate SDC step, avoiding excessive trace to trace variability. Another powerful but simple QC technique is to re-estimate the wavelets after certain steps and to compare them with the originally estimated wavelets (Fig. 5)

The output of an SDC step is either the input to the next SDC step or (in case of the last SDC step) input to an inversion algorithm. Each of the SDC steps has a number of input parameters, as does the final inversion algorithm. Setting all these inputs to their ideal setting is quite a job. One process that would benefit the practitioner is one of recipes: string all these operations together and each time you change a parameter, the entire process from that step onwards is re-run, and all intermediate steps and the inversion update, so that you can immediately see, typically on an arbitrary line through the wells, the impact of the parameter change. With the workflow optimized, a 3D volume can be generated. Running the workflow on multiple CPUs, etc is advisable as the numerous SDC steps and the inversion step can consume a lot of compute power per trace.

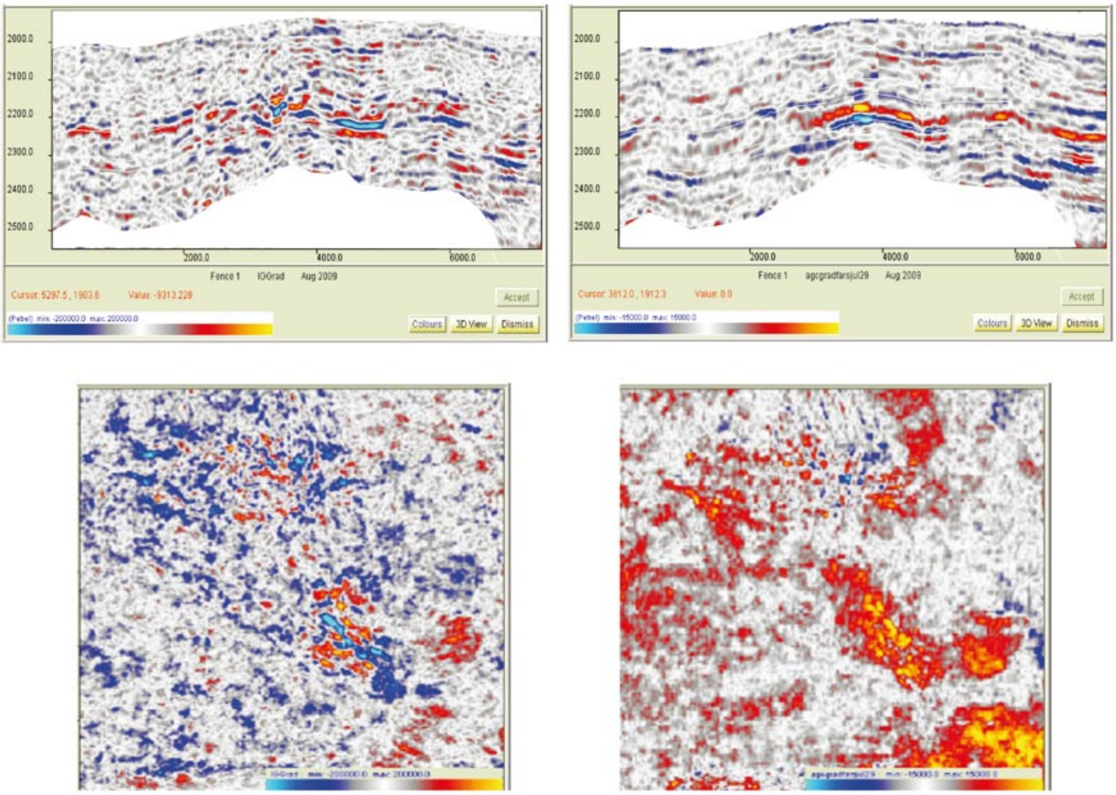

Figure 2 *Gradient section (top) and horizon extraction (bottom) derived from near, mid and far partial angle stacks, pre SDC (left) and post SDC (right). Post SDC Top reservoir clearly has a positive gradient as expected from Rock Physics analysis, and also note the improved continuity.*

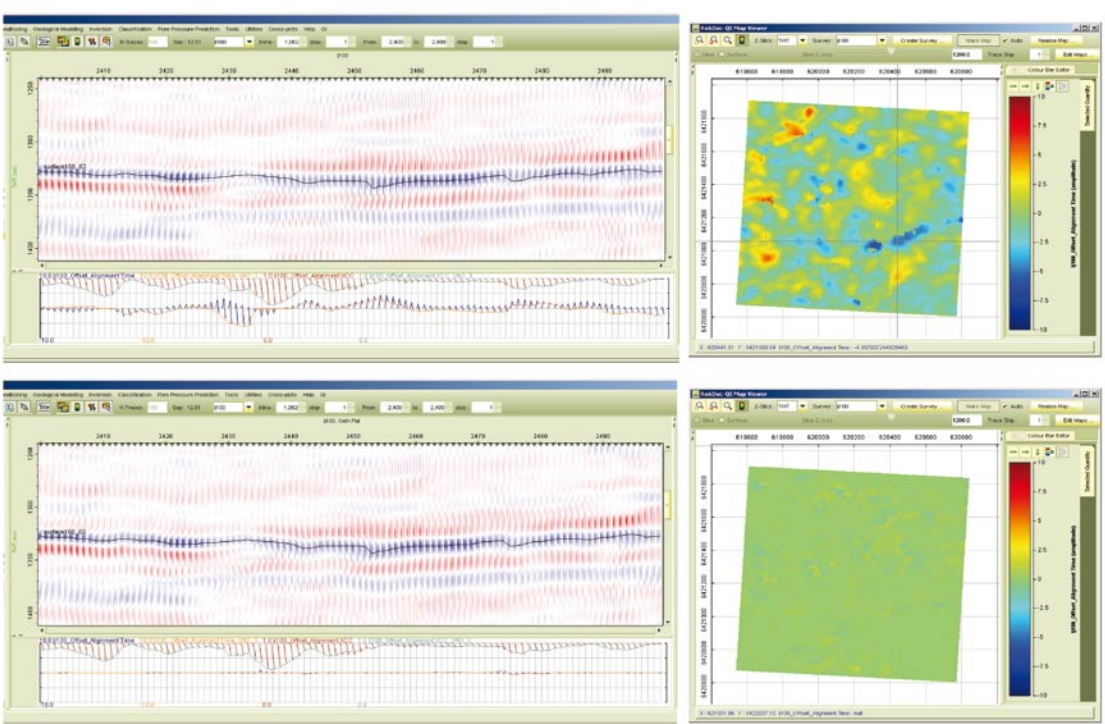

Figure 3 *Left, sections of pseudo gathers (near, mid and far partial angle traces grouped together); right, Top reservoir mis-alignment maps between far and near. Top pre-SDC, bottom post SDC. Below the sections the maximum cross correlation coefficient values at Top reservoir is shown (SDC invariant), as well as the mid/near and far/near mis-alignment. Post SDC this mis-alignment has essentially vanished.*

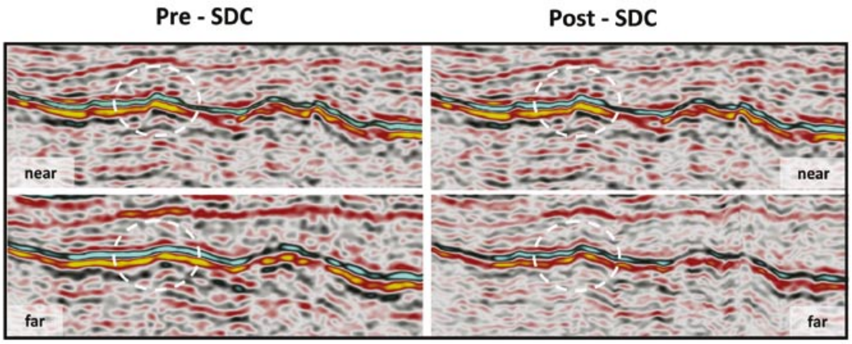

***Figure 4** Near and far partial angle stacks pre (left) and post (right) SDC. Using the near stack as the reference, the far stack has been frequency balanced and time aligned on the top peak. Seismic offset balancing, using a "background " AVO curve from wells, conditions the amplitudes ready for inversion. Note how post SDC the structure between near and far is better aligned.*

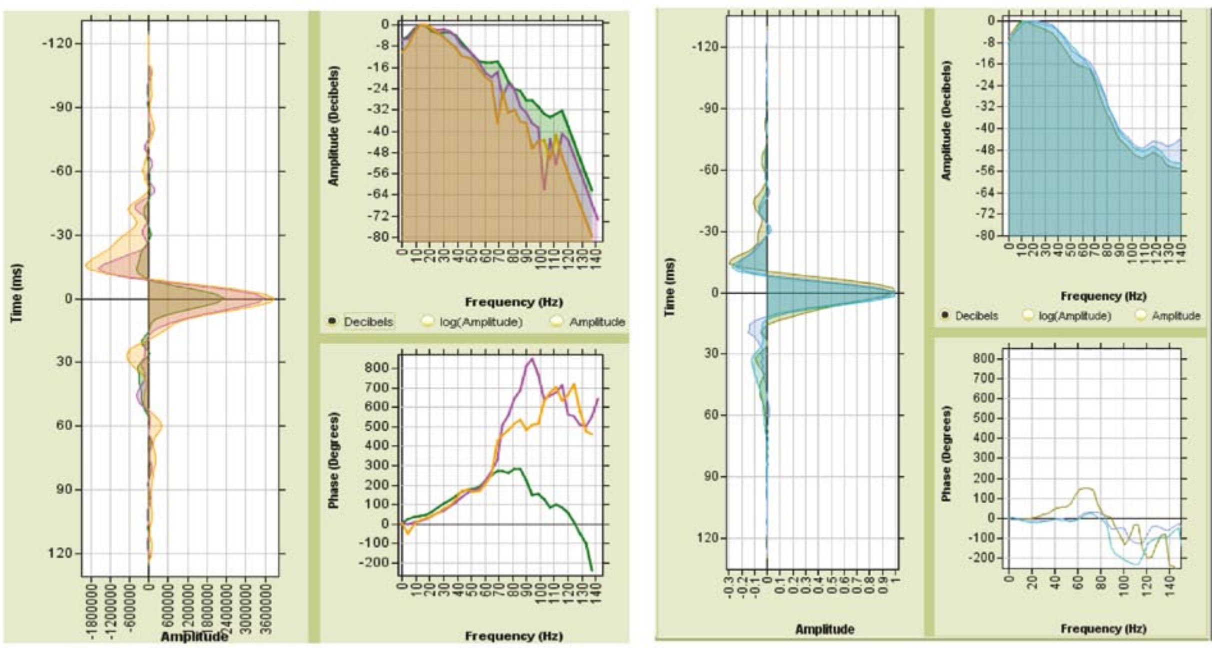

***Figure 5** Near, mid and far estimated wavelets, pre SDC (left) and post SDC (right). The improvement is marked.*

Conditioning of log data

Elastic logs are used in the inversion process to make low frequency background models, to provide constraints on the inversion, to calibrate and QC the inversion, etc. Therefore it is crucial to ensure that they are of the required quality prior to inverting the seismic.

Log data QC and a quality petrophysical evaluation form the starting point (see Fig, 6 for an example). Elastic profiles can be constructed readily from the petrophysically derived logs, but not where there are gaps (or where data quality is poor). Clearly if there is a lot of well control, a simple neural net approach may be applicable. Conversely, if well control is scarce it is better to use rock physics modelling to reconstruct the missing or bad log sections. A host of techniques are available; see for instance Avseth et al. (2005);

Rock physics study

Even though the data may be optimally conditioned and ready to be inverted, it is important that the practitioner takes a moment to determine what to invert to and which inversion algorithm to choose. The objective of the study (and deadline!) of course plays a major role. In an exploration setting you may decide that a full stack inversion to acoustic impedance is sufficient (although elastic/AVO inversion is something that is on the uptake in exploration); and in a development setting you may need to opt for a full-blown stochastic petro-elastic inversion. It is recommended that even when advanced inversion algorithms are chosen, a simpler form of deterministic inversion is run first as a yardstick, to see what already can be resolved.

Some practitioners invert to acoustic impedance, gradient impedance, shear impedance, elastic impedance, extended elastic impedance, Poisson's Ratio, Vp/Vs ratio, Lambda-Mu-Rho products, and so on. This is both unnecessary and utterly confusing to the recipient of the inversion results. Using well-based cross-plots, the two or three impedances that best discriminate the facies that you want to resolve or that are most sensitive to the required property can be readily determined in advance. See Fig. 7 for an example.

There is a tendency these days to always perform a broad-band inversion. However, this is not always needed; for instance, to determine net pay in reservoirs below seismic resolution, a band-limited extended elastic impedance approach is recommended (Connolly, 2007; Connolly and Kemper, 2007).

Inversion algorithms

Before reviewing the inversion algorithms, it makes sense to explain some nomenclature. There are two overall categories of inversions, deterministic and stochastic (note that geostatistical inversion is a form of a stochastic inversion). The former gives one result (the best it can do) and is entirely repeatable. However many impedance models can explain the seismic acquired (the seismic inversion problem is very much under-determined) and therefore over the years stochastic inversion schemes have been developed that give multiple equi-probable realizations of impedance, in the expectation that these multiple realizations 'contain' the correct impedance, i.e., span the solution space. Notice though that you can never say that a particular realization is the correct one! Stochastic inversions are not repeatable: if you re-run stochastic inversions you get slightly differing realizations and also be aware that running a stochastic inversion with a fixed random seed, whilst handy for debugging, is not appropriate.

Within stochastic inversion there are two branches, elastic and petroelastic. The former means that you invert to impedances, say acoustic impedance if you invert only

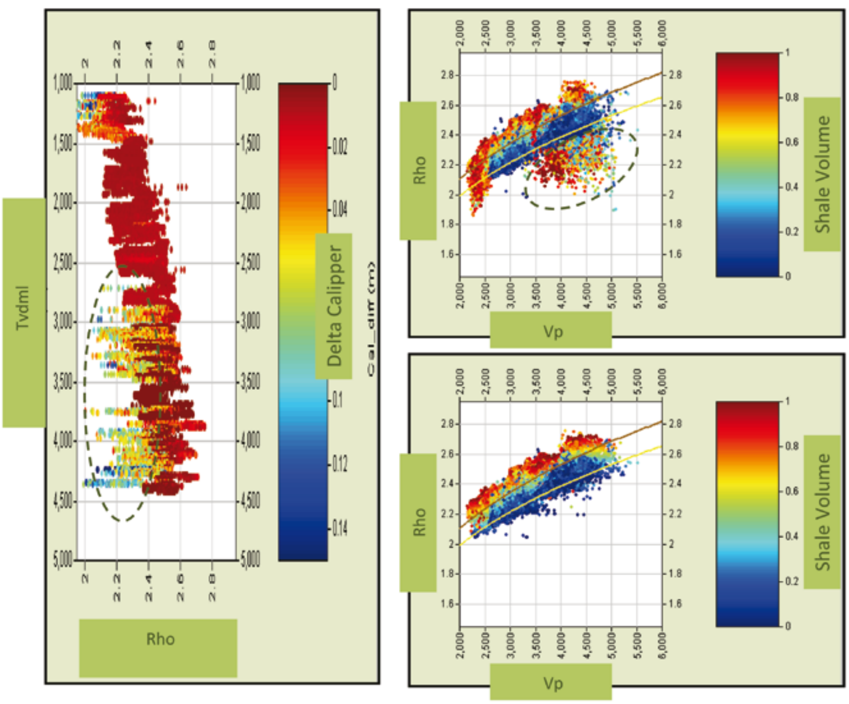

Figure 6 Log data conditioning example. The effect of washouts and borehole collapse, measured in the left plot, has an influence on the data quality seen in the top right plot; after correction the bottom right plot shows the rock physics trends much more clearly.

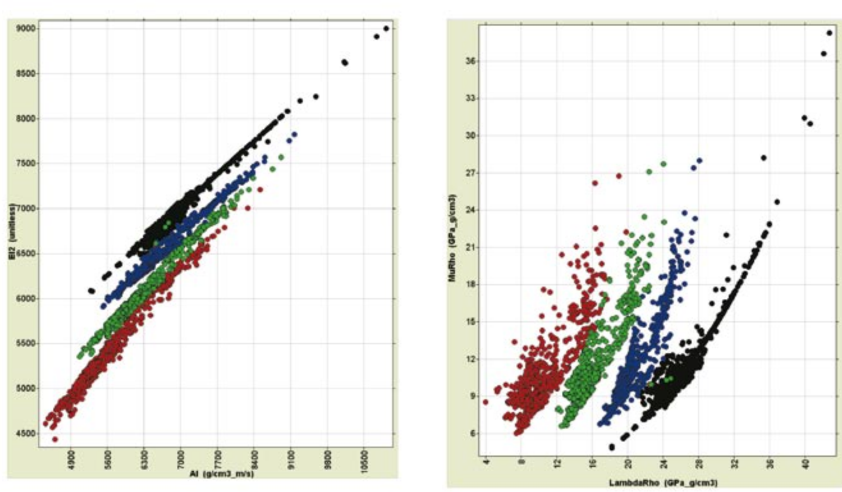

Figure 7 An AI/EI cross-plot (left) and an LambdaRho/MuRho cross-plot (right). Four facies are shown. It is clear that in this case LambdaRho and MuRho discriminate the facies better than AI and SI.

a full stack or acoustic impedance and shear impedance if you invert two or more partial stacks. The latter means that rock physics models (RPMs), relating petrophysical data to impedances, are used to invert straight to petrophysical properties such as Vshale, net-to-gross, porosity, and hydrocarbon saturation. Note that this can never be applied on full stack seismic alone. The relationship between petrophysical data and impedances is stochastic (i.e., a cloud; the relationship cannot be expressed analytically) and that is why only stochastic inversion can be petroelastic.

So in summary there are three types of inversion:
- Deterministic
- Stochastic-elastic
- Stochastic-petroelastic.

From this it is clear that no 'one size fits all' in seismic inversion, and therefore having a 'spectrum' of inversion techniques at your disposal is important. Many different inversion implementations exist (all belonging to the three main categories). Here five will be presented that are proven and excellent inversion techniques if applied to the right problem. They are listed below, and the type of inversion is shown in brackets
- Coloured inversion (Deterministic)
- Non-linear sparse spike inversion (Deterministic)
- (Model-based) simultaneous inversion (Deterministic)
- (Joint) geostatistical inversion (Stochastic-elastic)
- Bayesian inversion 'delivery' (Stochastic-petroelastic)

Coloured inversion: This technique popularized by BP some 10 years ago (Lancaster and Whitcombe, 2000) is one where an operator is designed to map the seismic spectrum onto an earth spectrum typically derived from well data. No wavelet is required, and coloured inversion cannot be applied simultaneously on multiple partial stacks. It is essential to ensure the seismic is zero phase. The impedance resulting from a coloured inversion is band-limited (comparable to the seismic spectrum, although it benefits from some spectral blueing). Should a broad-band result be required, a low frequency background model (for instance, by kriging well impedance profiles collocated by seismic stacking velocities; the fact that seismic contains ever lower frequencies is excellent, but the very lowest frequencies are still crucial) can be spectrally merged in. It is a quick and easy-to-use technique and is recommended as a first pass inversion. See Fig. 8 for an example.

Non-linear sparse spike inversion: Classical sparse spike inversion is a relatively old, one-step technique (Debeye et al, 1990). Given a representative wavelet, key loops in the seismic to be inverted are replaced by reflection spikes as sparsely as possible and with such locations and amplitudes that, when the spikes are convolved with the wavelet that the synthetic seismic obtained, approximates the seismic. From the spike field the relative impedance is obtained by simple integration, with some anti-drift constraints to keep it band-limited. A low frequency background model may be spectrally merged in afterwards to yield absolute impedance.

In non-linear sparse spike inversion the above method is inserted in an optimization loop, and the wavelet is updated (non-linearly, hence the name of this inversion technique) so that the mismatch between the synthetic and actual seismic is minimized, whilst still keeping the wavelet shape realistic and wavelet length short. In addition, per iteration, a (small) sliding window passes over the inversion gate and identifies areas where the mismatch is poorest, and attempts alternative spike arrangements, with some sparseness constraints. This complex twist to the sparse spike technique can give excellent results as shown in Fig. 9.

Non-linear sparse spike inversion, which cannot be run simultaneously on multiple partial stacks, is recommended in areas with very few or no wells (as an optimal wavelet is developed as an integral part of the inversion process) and can give robust results in areas where data quality is moderate to poor, often onshore, e.g., for shale gas plays.

Simultaneous inversion (model-based): Zoeppritz (1919) solved the problem of an acoustic wave incident on a surface. This complex, non-linear formulation for the P-wave reflectivity Rpp(θ), whilst useful in forward modelling the seismic response, cannot be analytically inverted, and therefore is not suited for seismic inversion without alteration. Over the years a number of linear approximations (small angle, small

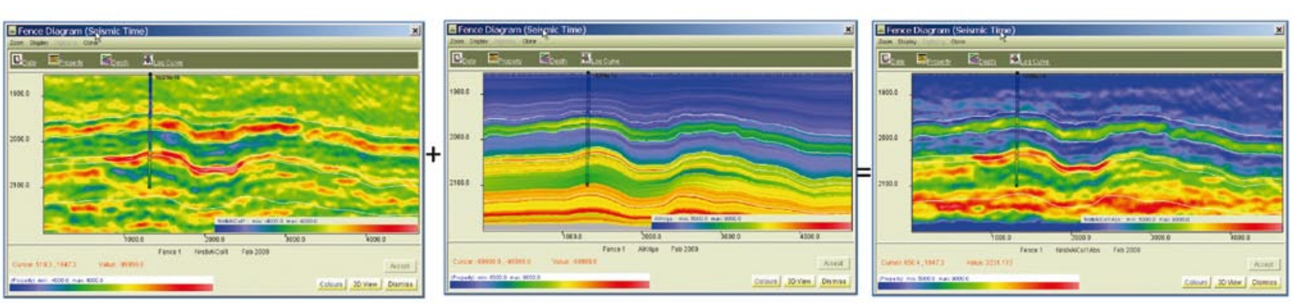

***Figure 8** A relative coloured inversion section (left), a low frequency background impedance model (centre). These two can be spectrally merged to provide an absolute coloured inversion section (right).*

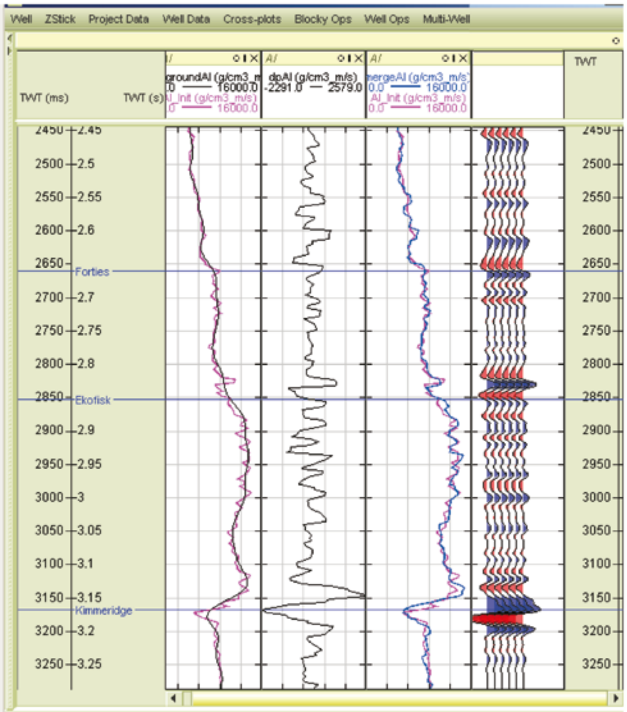

Figure 9 A Non-Linear Inversion example at a well. First track: the AI log (pink) and (black) the low-passed filtered AI log, i.e. the low frequency background model; Second track: the relative NLI inverted AI trace; Third track: the AI log (pink) and (blue) the absolute NLI inverted AI trace, i.e. the relative NLI inverted AI trace spectrally merged with the low-passed filtered AI log. The Match is excellent; Fourth track: the seismic trace as the well (repeated) which was NLI inverted.

contrast) have been derived by Bortfeld (1961), Aki and Richards (1980), Wiggins et al. (1984), Smith and Gidlow (1993), Fatti et al. (1994), Gray et al. (1999), and Gray (2002), and these are all of similar form:

$$Rpp(\theta) = aR_1 + bR_2 + cR_3 \qquad [1]$$

Where:
a, b, c are values depending on θ and field constant $K = (Vs/Vp)^2$. R_1, R_2, R_3 are traces representing the contrast/reflectivity in elastic properties (Note: the 3rd term is often ignored, especially when θ is small)

To make formula [1] concrete, the Smith and Gidlow and Fatti approximation [2] to Zoeppritz' formula is used throughout, which in form is identical to [1].

$$Rpp(\theta) = aR_{AI} + bR_{SI} + cR_{Rho} \qquad [2]$$

If there are N partial stacks, formula [2] can be written N times, each time using the θ belonging to the corresponding partial stack. This set of equations can be written in block matrix form, and as long as $N \geq 3$, R_{AI}, R_{SI} and R_{Rho} can be derived simultaneously, and optionally individually inverted to acoustic impedance, shear impedance and density respectively. However, in order to *simultaneously* invert to these three impedances, it has to be realized that any reflectivity R can be written as R = (Imp2 - Imp1) / (Imp2 + Imp1), which for small contrasts can be approximated by $R \approx ½\Delta\ln(Imp)$. Substituting this in [2] gives ...

$$Rpp(\theta) = ½a\Delta\ln(AI) + ½b\Delta\ln(SI) + ½c\Delta\ln(Rho) \qquad [3]$$

So far this has been expressed as reflection coefficients. To get to band-limited seismic, convolve with the appropriate wavelet W(θ), noting that W(θ) Rpp(θ) is denoted as S(θ), the S representing seismic.

$$S(\theta) = ½aW(\theta)\Delta\ln(AI) + ½bW(\theta)\Delta\ln(SI) + ½cW(\theta)\Delta\ln(Rho) \qquad [4]$$

This time formula [4] can be written N times, each time using the θ belonging to the corresponding partial stack. This set of equations can also be written in block matrix form, and as long as $N \geq 3$, ln(AI), ln(SI) and ln(Rho) can be solved together, i.e., simultaneously! Note that a trivial exponentiation gives the acoustic impedance, shear impedance, and density required.

In practice solving [4] for N partial stacks results in some inaccuracies and different implementations have different ways of dealing with that, from insisting that both ln(SI) and ln(Rho) are linearly related to ln(AI), to using statistical RPMs. A poor implementation can result in artifacts in the inversion results (e.g., SI can be overly correlated to AI).

Simultaneous inversion is quick and robust and the fact that AI, SI, and Rho are simultaneously solved, makes these results of a better quality than when derived individually. Simultaneous inversion is a widely used inversion technique in the appraisal and development phases of a field (and increasingly in the exploration phase also). See Fig. 10 for an example.

Geostatistical inversion (joint): Geostatistical inversion, popularized by Haas and Dubrule (1994), starts by posting well impedance profiles (the user chooses the impedance 'flavour') in an 'empty' carefully constructed structural and stratigraphic geological model. Subsequently a random empty trace position is selected ('random walk') and geo-statistical simulation (3D sequential Gaussian simulation, perhaps collocated by a deterministic inversion) is performed to propose impedance candidates. After differentiation and convolution with the appropriate wavelet, a number of candidates are normally rejected until a candidate impedance trace matches the seismic over the selected gate, by exceeding a correlation threshold. This accepted impedance trace now becomes a new 'well', and the process repeats at a subsequent random empty trace position, until accepted impedance traces over the whole structure have been obtained.

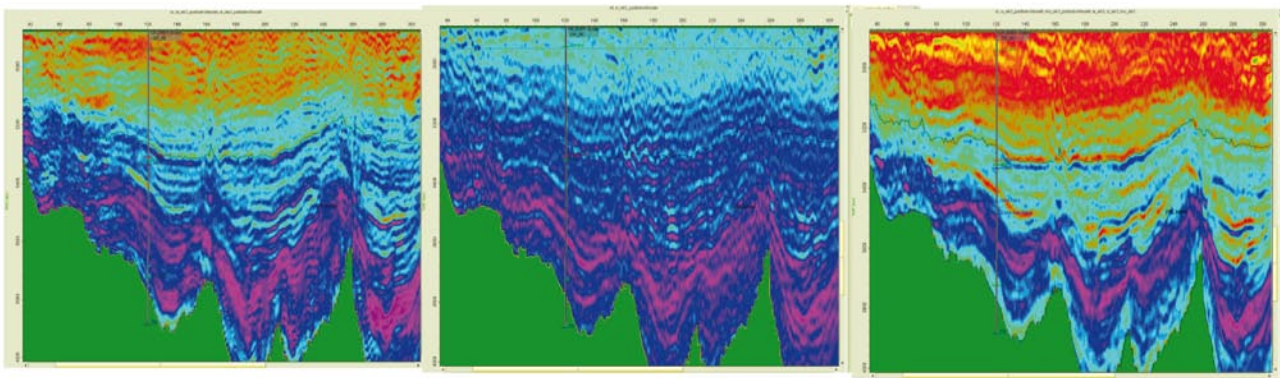

***Figure 10** Model based simultaneous inversion sections: Acoustic Impedance (left), Shear Impedance (middle) and Density (right). Good detail is observed, even in the density section.*

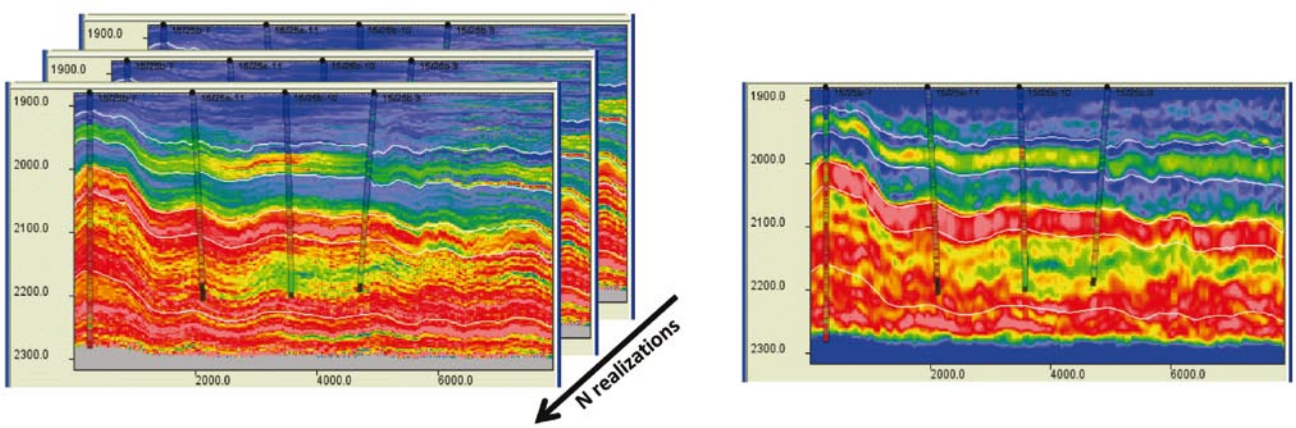

***Figure 11** Three geostatistical inversion realizations of Acoustic Impedance (left) and a deterministic Acoustic Impedance result (right) over the same arbitrary line. The match at the wells is guaranteed in geostatistical inversion, and frequency content is demonstrably higher.*

One impedance realization has now been derived. Subsequently the whole process is repeated with a new random seed until N equi-probable impedance realizations are obtained, to be analyzed in their totality. What number N to use, as well as what acceptance criteria and other parameters to use, will be determined by performing this process on a 2D arbitrary line first. Geostatistical inversion is a broadband inversion, from 0 Hz to the Nyquist frequency of the time sampling (typically 1 ms or less). Of course the match criteria can only be established over the seismic frequency band; but by using this method, which results in multiple equi-probable realizations, the solution space is covered over the whole frequency band, one of the most attractive features of this inversion. Geostatistical inversion, which needs a good number of wells to start with, is an inversion typically used in appraisal and development. See Fig. 11 for a comparison with a deterministic inversion.

Statistical RPMs can be used (so called cloud transforms to be precise – see Fig. 12) to turn this process into a *joint* geostatistical inversion. The cloud transform, typically derived from well data, captures the relationship between the two (or three) target impedances, e.g., AI and SI. Once N AI realizations have been derived, incorporate the cloud transform in the stochastic inversion to SI. The cloud transform will ensure that pairs-wise the N AI and SI realizations have characteristics corresponding to the wells. Joint geostatistical inversion is of course also an inversion typically used in appraisal and development, but can also be used in a 4D setting. To do this, in this paragraph simply replace AI by, say, the reference survey Poisson's Ratio, and replace SI by the monitor survey Poisson's Ratio!

Bayesian inversion: Delivery is an open-source Bayesian inversion package (Gunning and Glinsky, 2004), entirely without a graphical user-interface (i.e., it is command line driven). Bayes' Theorem in an inversion context is well described elsewhere (e.g., Avseth et al, 2005) and can be distilled down to :

Posterior distribution α Prior distribution x Likelihood distribution [5]

Explaining this relationship for seismic inversion, the prior distribution describes, in the form of probability density

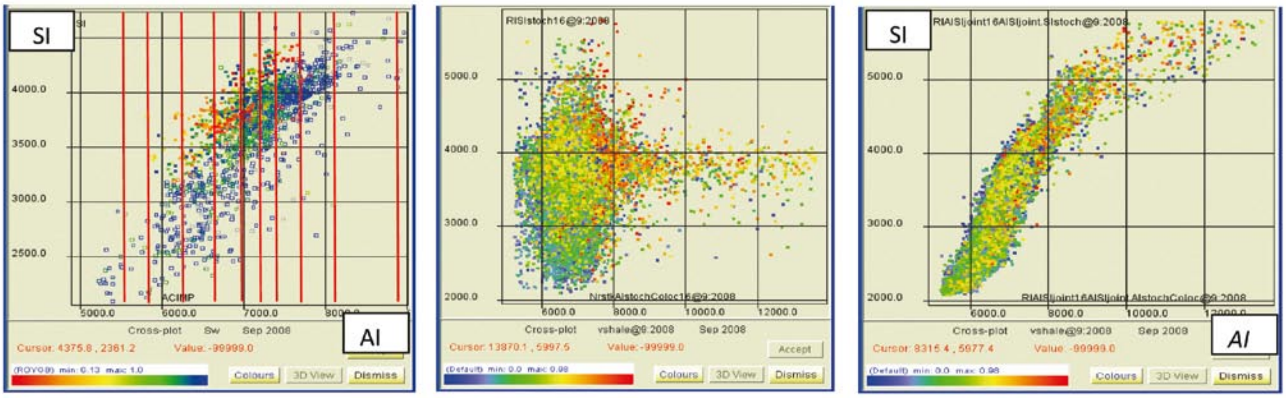

Figure 12 *Three AI/SI cross-plots. Left the representative well data is displayed, and bins are indicated with red lines. Per bin a cumulative density function (cdf) relating SI to AI can be established. All these cdf's together form the cloud transform. In the middle plot realizations from two independent geostatistical inversions, one to AI and one to SI, are cross-plotted; the character does not match the well data. In the right plot AI and SI realizations from one joint geostatistical inversion, which utilized the Cloud Transform, are cross-plotted pairs-wise; the character does match the well data.*

functions (PDFs), everything known about the subsurface prior to an inversion. For instance, you know that top reservoir is along a picked horizon, but there is picking uncertainty that can be captured. From depth trend analysis you may know compressional velocity as a function of true vertical depth below mud-line, but there are usually 'dotted lines' that describe the uncertainty in this relationship. Fluid properties are usually not known precisely, and thus can be described using a PDF. So from the complete prior distribution, N realizations of the earth can be drawn at a particular trace location. From this impedance profiles can be derived, which after differentiation and convolution with the appropriate wavelet result in N synthetic seismograms as shown in Fig. 13 (left), where the seismic trace, not used to construct the prior distribution, is superimposed. The overall shape is captured, but there is a wide distribution around the seismic trace.

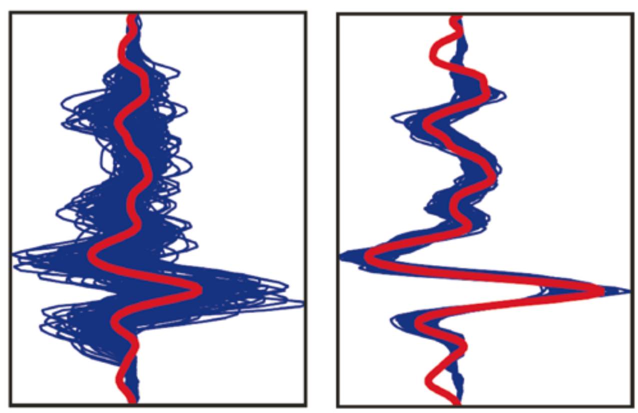

Figure 13 *100 traces from the prior distribution (left) and 100 traces from the posterior distribution (right). In both cases the seismic trace is shown in red. Clearly using the seismic to 'constrain' the prior information improves the match enourmously. From Gunning and Glinsky (2004), with permission.*

The likelihood distribution incorporates the seismic and represents the probability that, given the prior distribution described, the seismic will be replicated. This is achieved by comparing the synthetic seismic with the actual seismic data.

Multiplication of the prior distribution with the likelihood distribution gives the posterior distribution. Again N synthetics are drawn, this time from the posterior distribution (Fig. 13 – right) clearly representing the seismic trace more accurately. Normally synthetics are drawn from the posterior for inversion QC. If these match the seismic well, much additional statistical information can be drawn from the posterior distribution with confidence. As an example, in Fig. 14 a dipping reservoir model is generated and the seismic synthesized, which then is Delivery inverted. Per trace 15 Vp realizations are shown. The impedance values are very distinct between facies (so reservoir properties and pore-fill are inverted with great confidence in this case) but, in the water-leg the top and base reservoir, uncertainty is quite significant. Most inversion methods do not invert for layer boundary position, so this is a unique and attractive feature of Delivery.

Delivery is a broadband inversion, and being petroelastic can give probability estimates of porosity, Vshale, net-to-gross, saturation, etc. Presently it is used as a specialist inversion tool, but with the right user interface could be driven by specialists and non-specialists alike. Sampling from the posterior is slow, and therefore sufficient compute power distributed over many CPUs is advised.

Reservoir characterization

In too many cases, inverted data, acquired at great expense of time and money, are not used to great effect. Therefore six reservoir characterization techniques that extensively use inverted datasets are listed here briefly as an *aide memoire*.

Bayesian classification: Well impedance profiles (say AI and EI, high-pass filtered) can be cross-plotted and coloured by facies. From the coloured 'clouds' of data two-

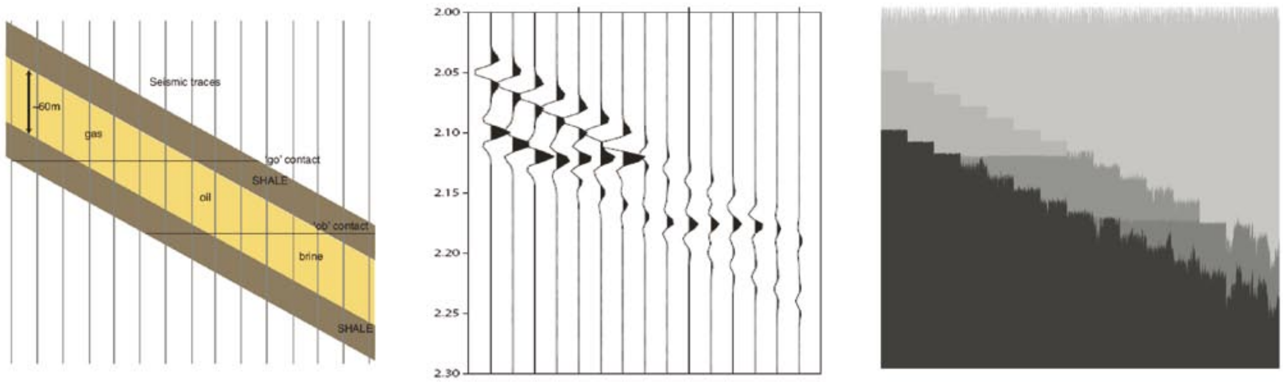

Figure 14 *Dipping reservoir model with GOC and OWC (left), the corresponding synthetic seismic section (middle) and the Delivery inverted section (15 realizations per trace position). Note how depth uncertainty at contact is much smaller than at top or base of the layer. From Gunning and Glinsky (2004), with permission.*

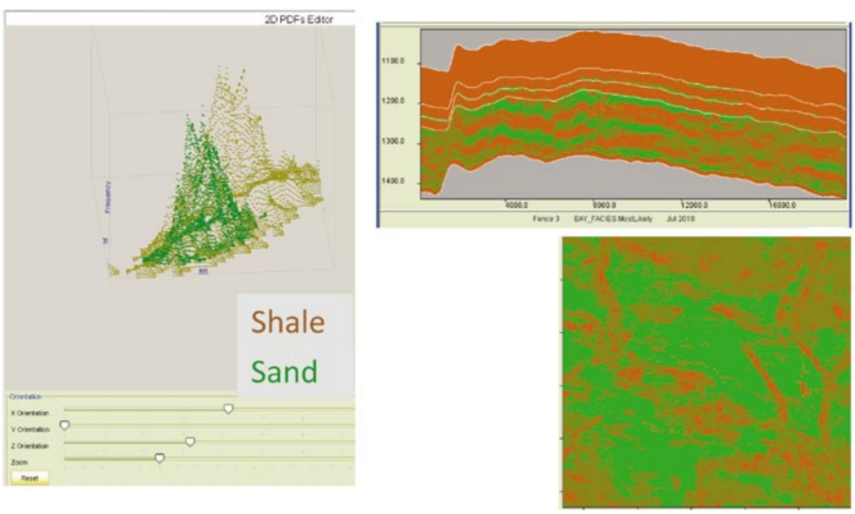

Figure 15 *Sand and Shale prior 2D AI/EI PDF's are created (left) by cross-plotting AI and EI per facies (more than 2 facies are possible). By entering with AI/EI pairs (from inverted AI and EI datasets), the most likely posterior facies can be determined, as shown (right) in the section and horizon slice. Facies probability cubes can also be output and displayed.*

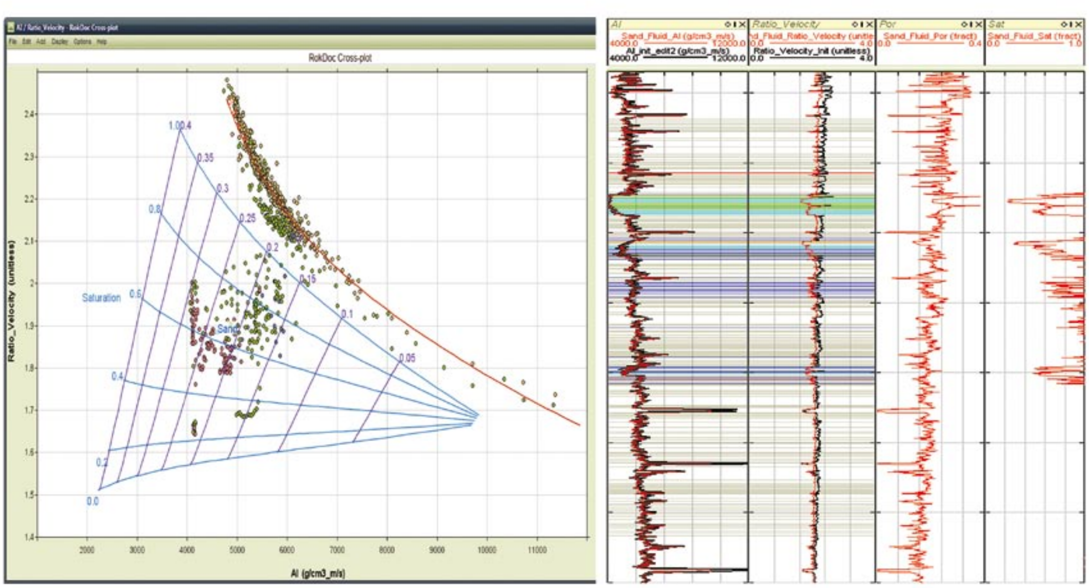

Figure 16 *A Rock Physics Model Template (with porosity increasing right to left and hydrocarbon saturation Sh top to bottom; a single sandy shale line also forms part of this RPM template) is carefully positioned on top of well AI & Vp/Vs profiles (left). Using the RPM template, porosity and Sh can be obtained by reverse modelling (right, last 2 tracks). In addition to using this on well AI & Vp/Vs profiles, this process also works with inverted AI & Vp/Vs cubes.*

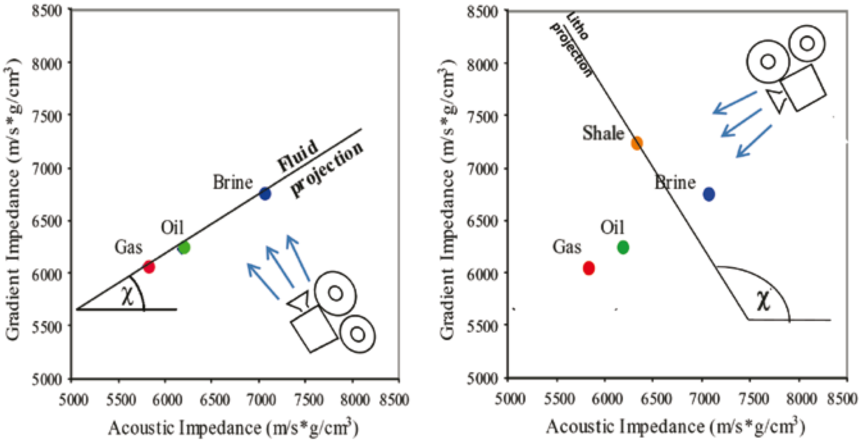

Figure 17 Using AI/GI cross-plots, EEI (≈ AI cosχ + GI sinχ) quantities called "Fluid projection" (left) and "Litho projection" (right) can be constructed.

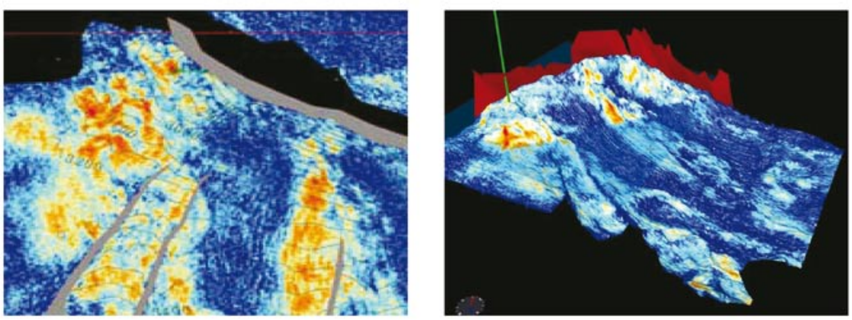

Figure 18 Example "Litho projection" (left) and "Fluid projection" (right). Note the stunning amplitude switch off in the fluid projection image, representing an OWC. From Connolly, P., Schurter, G., Davenport, M. and Smith, S [2002] Estimating net pay for deep-water turbidite channels offshore Angola, EAGE abstracts, EAGE 64th Conference & Exhibition, with permission.

dimensional PDFs can be created as shown in Fig. 15 (left). For all AI and EI pairs (from two inverted datasets), facies probability can be determined. In Fig. 15 (right) the most likely facies is shown.

RPM template inverse modelling: Using established rock physics modelling techniques, RPM templates can be overlain on cross-plotted impedance data (Fig 16 – left). The RPM template has porosity increasing from right to left and hydrocarbon saturation (Sh) from top to bottom. Once the RPM Template is positioned satisfactorily, Porosity and Sh can be readily obtained by inverse modelling (Fig. 16 - right).

EEI illumination: Extended Elastic Impedance (Whitcombe et al., 2002) is a linear combination of Acoustic Impedance and Gradient Impedance and as explained in Fig. 17 can be tuned to either illuminate lithology or fluids. Fig. 18 shows an example of both; note the spectacular amplitude switch-off on the Fluid EEI, representing an OWC.

Seismic net pay: Connolly (2007) describes how the average value of an appropriately chosen EEI attribute corresponds with seismic net-to-gross. Multiply with seismic gross thickness (the time difference between the two horizons) and a seismic net pay estimate is obtained, which can be calibrated to available well data if needed. Fig. 19 shows an example.

Collocated co-kriging: To obtain a porosity property from an inverted impedance cube, krige the well porosity profiles, collocated by the impedance cube as a so-called soft property.

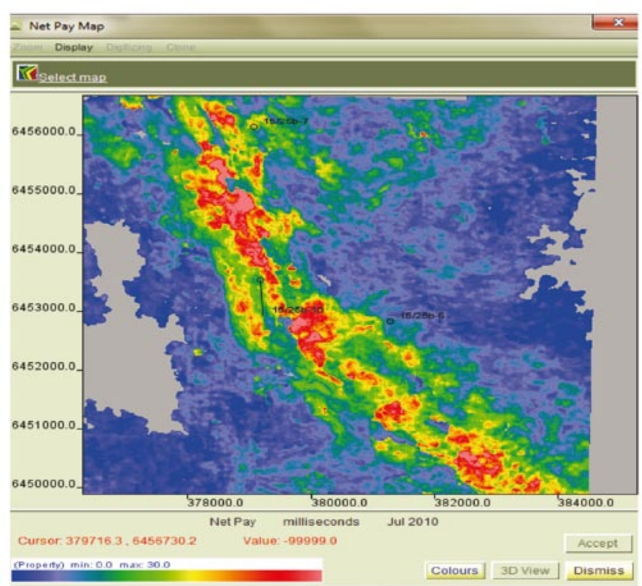

Figure 19 Example of a Seismic Net Pay map. This can be used in volumetrics and well planning.

Fig. 20 shows that the result has the required statistics and is guaranteed to fit at the wells, which is attractive.

Multi-realization analysis: Equi-probable realizations, resulting from a Stochastic Inversion, are to be analyzed in their totality. Figs. 21 and 22 give some powerful examples.

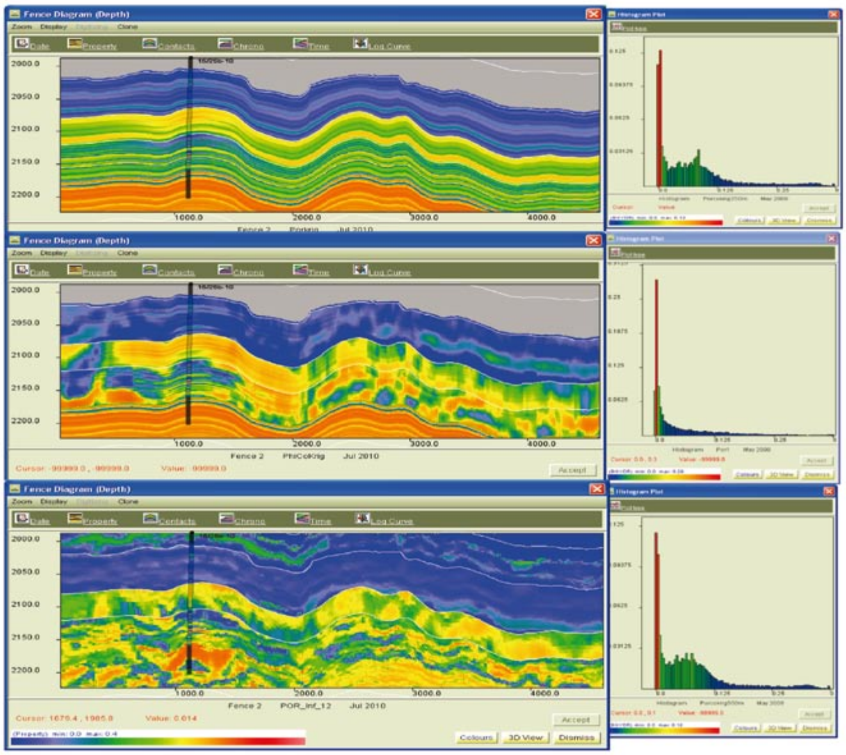

Figure 20 Porosity sections (left) and porosity histograms (right). Top is porosity by kriging well porosity profiles only, i.e. no inverted impedance volumes are used. The resulting porosity model is too smooth. Middle is porosity from a neural network trained at the wells to predict porosity from an inverted impedance volume. Although the result 'looks' credible, the statistics are poor (compare top and middle histograms). Moreover, no fit at the wells is guaranteed. Bottom is porosity by kriged well porosity profiles, collocated by an inverted impedance volume with the right weight. The result looks credible, statistics are excellent and the fit at the wells is guaranteed.

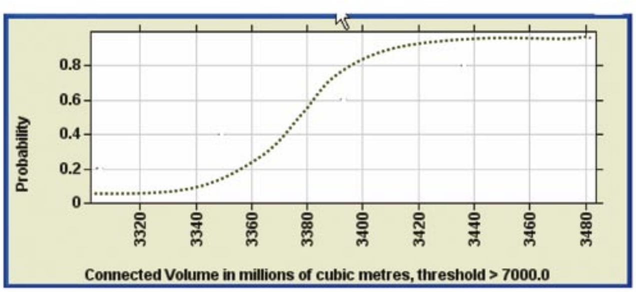

Figure 21 At a user-specified seed point (e.g. A proposed well target) all N realizations (or pairs or trios of realizations) of a stochastic inversion are visited, and for each the connected volume, given some criterion, is calculated. After sorting the N values, a connected volume cumulative density function is created as shown.

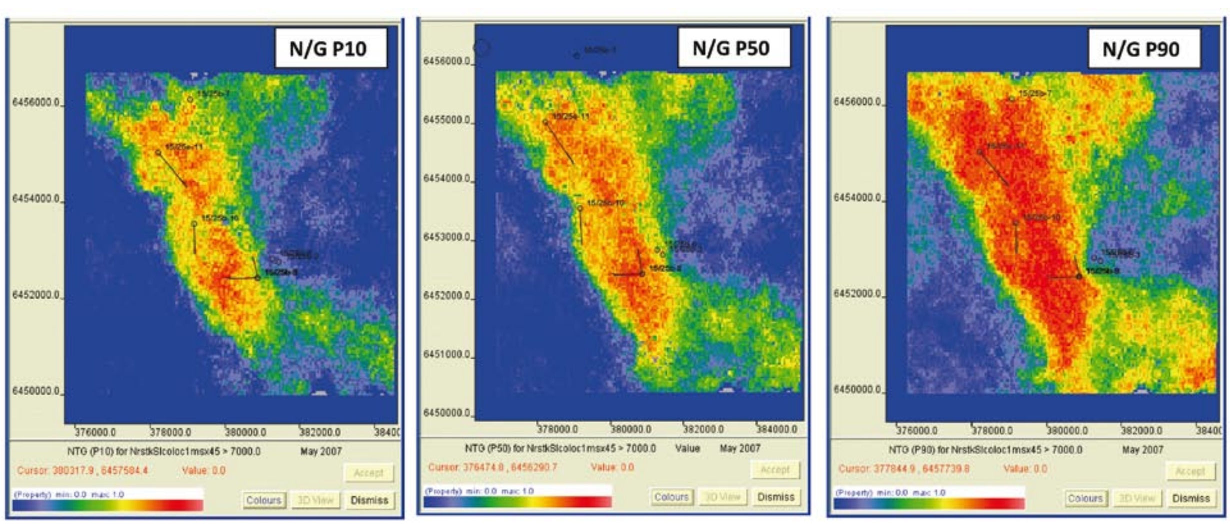

Figure 22 By visiting all N realizations (or pairs or trios of realizations) of a stochastic inversion, N Net-to-Gross can be determined. After ranking, P10, P50 and P90 Net-to-Gross maps can be created, as shown.

Discussion and conclusion

In this paper a general workflow is described to derive a variety of seismic inversion results, even though seismic inversion as described in this paper is under attack! Joint inversion techniques, inverting multi-component and multi-azimuth seismic dataset as well as EM data, FTG gravity data, etc, are maturing. And in the future 3D full waveform inversions will perhaps supersede many of our current methods. Nevertheless, seismic inversion, of which this paper gives a by no means exhaustive review, will continue to fulfill the basic role of deriving useful predictions of reservoir properties from seismic data

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