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Seismic Reservoir Characterization

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ABSTRACT

The body of the oral presentation consists of examples taken from international case studies, highlighting the application of some recent advancements in 3D seismic technology towards reservoir characterization including:
Neural network technology facilitating facies interpretation in a turbiditic fan complex.
3D Impedance-Layer Inversion allowing delineation and quantification of channel sands.
4D seismic analysis at the Oseberg field

Each reservoir is unique: physically, economically, conceptually—choosing the economically appropriate seismic methods for reservoir characterization requires understanding the relationships between seismic estimates of reservoir properties.

INTRODUCTION

Increasing difficulty in the discovery of petroleum reserves, and decreasing economic margins in their production—especially in deepwater—is being met by a technical readiness & organizational will to shift resources towards improving the profitability of existing assets. Today, advances in seismic integration technology are dovetailing with developments in corporate culture towards optimizing integrated reservoir management.
Since the early 1980s integrating 3D seismic into the reservoir model has, for many oil companies, acted as a catalyst for effecting change in organizational behavior and business practices throughout the reservoir characterization process. Companies that early embraced this technology for better structural information have realized large gains in productivity in terms of finding & managing reservoirs. The successful campaign in the Campos Basin[1] has shown that the synchronization of 3D seismic studies during exploration & development phases, has resulted in a significant reduction in drilling costs: doubling the exploration success ratio, and reducing by one third the appraisal time.
With recent advancements in information technology & multidisciplinary organization, tackling the more complicated task of utilizing seismic information to describe the reservoir's rock & fluid properties has become more feasible within the timeframe necessary to have impact on reservoir management. Progress in data management software is translating to less creative capital being spent on data recuperation (currently about 30% project time) and more on the understanding of the reservoir. Borrowing some terminology from the automobile industry, these developments—progressing from the less cost-effective, synergy sterile "assembly-line" practices of the past—make possible "just-in-time" knowledge integration. In this vein, 4D seismic, repeated 3D seismic over a producing field, has the potential to map changes in fluid properties and contribute, in conjunction with permanent sensors and simulation, to real-time reservoir management. Efficiently obtaining maximum value from seismic information—as well as geology & engineering—requires stepping back from viewing data acquisition, processing & interpretation as specific tasks, and regarding rather where synergy can be achieved in the reservoir characterization process[2].
With the innovative technical solutions that have kept E&P projects viable against the background of falling oil prices, has come the trend, both for tasks & decision making, towards forming multidiscipline, asset teams. Economic risk is usually the dominating concern of asset teams for reservoir management. To delay abandonment in large, older fields is clearly an economic incentive to improve reservoir characterization; however, there is a school of thought that believes that the E&P business is not datacentric[3]: at appraisal & development, data is expected to be incomplete and possibly inconsistent. Data (additional reservoir simulations, seismic acquisition, etc.) is sometimes viewed as being acquired for defensive purposes by practitioners with vested interests. To maximize efficiency requires recognizing that the decision level determines the most appropriate technology to employ. Reservoir characterization efforts for the prediction & quantification of uncertainty may not be appropriate when it is rather a case of *managing* uncertainty.

TOWARDS AN INTEGRATED SOLUTION

The *integrated solution* views each reservoir as unique—the varying quality & quantity of measurements describing its static & dynamic properties accentuating this uniqueness—and geostatistics, deterministic methods, inversion, neural nets, multivariate statistics, data fusion, etc. as alternatives for the integration of seismic in the reservoir model. Developments in this area are towards combining these various techniques, while incorporating geological, petrophysical & fluid models to obtain a better estimate of porosity, lithology, fluids and hydraulic connectivity with associated uncertainty.

Where seismic can contribute to the reservoir model (**Figure 1**) will depend both on the quality of the seismic information, and on the non-seismic data type, scale, quantity, and quality.

Utilizing sequence stratigraphy to build a high-resolution chrono-stratigraphic framework of the reservoir is often an essential element in predicting vertical discontinuities & lateral variations in the rock matrix. Combined with the petrographic model from thin-section analysis, this forms the basic work model for defining the control of fluid flow. Seismic information is integrated through the qualitative interpretation of the seismic signatures and through quantitative methods like inversion, multivaritate statistics, and geostatistics.

Figure 2 shows in more detail the influence of seismic information in fluid flow simulation/history-matching—the Seismic-to-Geological Model arrow representing the process shown in **Figure 1**. Errors in characterizing the reservoir's static properties become to a certain extent less important in the initial analysis of 4D seismic: With the geology remaining constant, analyzing another seismic shapshot to monitor fluid movement is a simpler task because the contribution of the static state of the reservoir to the seismic response is suppressed, thus isolating areas of fluid & rock property change due to production. Geologic/Petrophysic models are then used to quantify the 4D seismic results, and in its reconciliation with the production data and reservoir model. In addition to sharing the same problems of history-matching—upscaling assumptions, effective properties, domino effect—seismic quantification, which usually relies heavily on synthetic seismograms, requires transforms to estimate velocity and density as a function of the spatial distribution of rock & fluid properties.

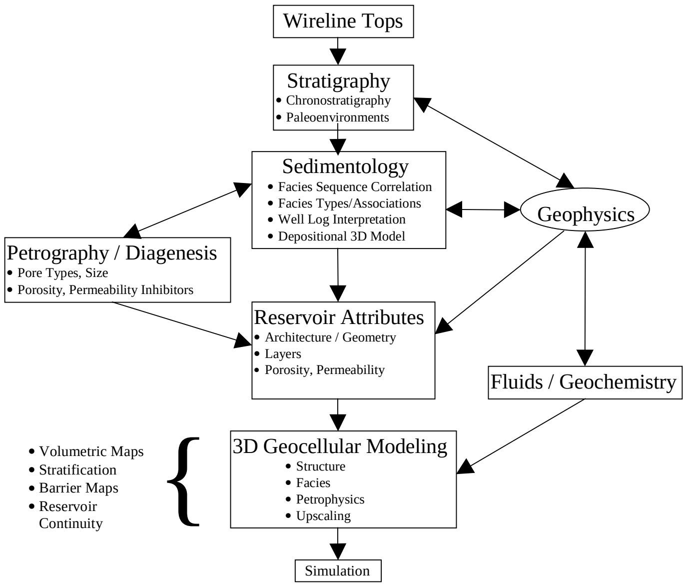


Figure 1—Greater than the sum of its parts—simplified influence diagra of the initial phase of the reservoir characterization process.

Seismic Methods. Choosing the economically appropriate seismic methods for reservoir characterization requires understanding the relationships between seismic estimates of reservoir properties. Absent from **Figure 3** are the numerous potential inputs from non-seismic sources that could occur during the integration process.

A reservoir geophysics program is tailored to support geologic work focused on engineering objectives, to achieve the most accurate estimation of volumetrics, reservoir compartmentalization and fluid flow. Faulting and structural expression of the reservoir are usually the more reliable interpretations obtained from seismic data. Knowledge of reservoir architecture is the most important element in successful reservoir management, therefore we should continue our emphasis in obtaining finer fault imaging and accurate depth estimates with associated uncertainty.

Volumetrics & permeability estimates are primarily supported by interpretation and quantification of the structural expression: time surfaces converted to depth (depth imaging & velocity analysis); seismic facies; and, faults & associated fractures (generic analysis of structural deformations). Fracture orientation & density are more directly obtained through compressional-wave AVAz (Amplitude Versus Azimuth/Offset[4]) and 3-Component shear wave analysis[5]. Porosity & fluid

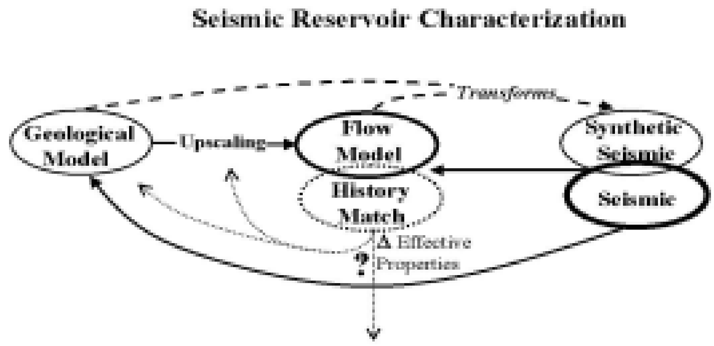


Figure 2—4D Flow—In addition to sharing the same problems of history-matching, seismic quantification, which usually relies heavily on synthetic seismograms, requires transforms to estimate velocity and density as a function of the spatial distribution of rock & fluid properties.

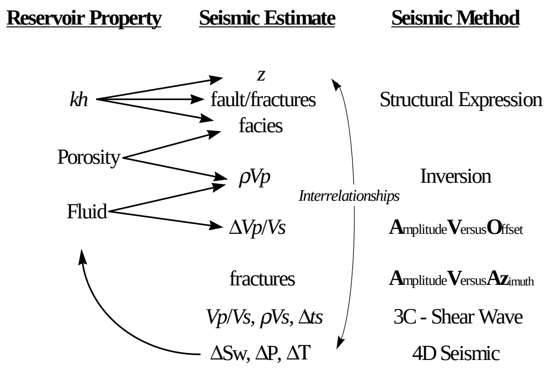


Figure 3—Proper Methods—Choosing the economically appropriate seismic methods for reservoir characterization requires understanding the relationships between the seismic estimates of reservoir properties.

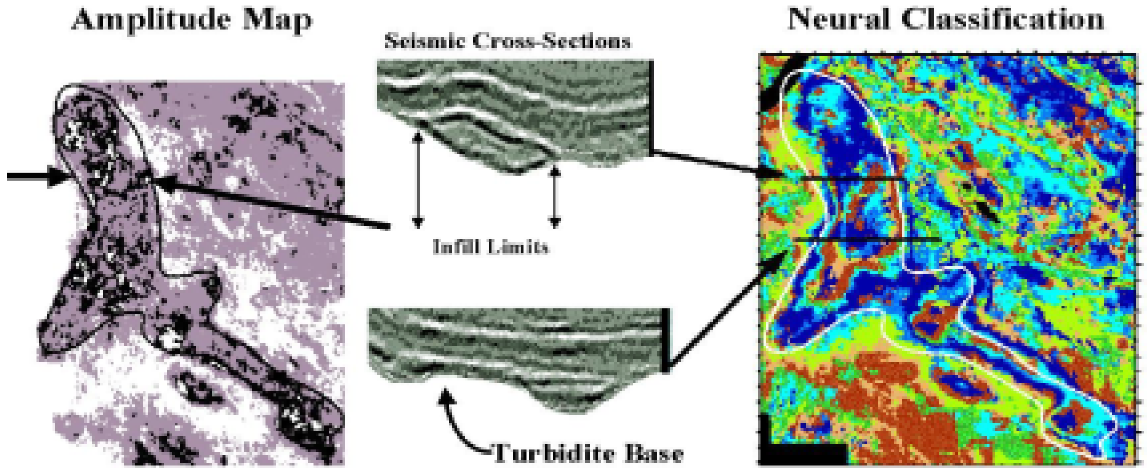
estimates are primarily supported by acoustic impedance inversion and facies analysis. To aid in differentiating the poststack seismic response to changes in porosity, fluid & lithology effects, AVO (Amplitude Versus Offset) analysis is used to obtain estimates of changes in the ratio of compressional-wave velocity to shear-wave velocity (*Vp/Vs*). A more direct measure of *Vp/Vs*, *Vs* and ρ*Vs* is the 3-Component seismic method. The 4D Seismic method directly estimates changes in water saturation, pressure & temperature, and estimates indirectly porosity & permeability by mapping fluid pathways and bypassed oil.

Case Studies. The following three case studies illustrate the application of the appropriate seismic method given the objective of the study and relation of the seismic estimate to the critical reservoir property:
Seismic Facies Interpretation facilitated & augmented by automatic image analysis.
3D Layer Inversion to acoustic impedance allowing delineation of sand channels.
4D Seismic analysis at the Oseberg field

SEISMIC FACIES

Conducted at Elf Exploration Production, this study illustrates the use of image analysis[6] to augment & facilitate the seismic interpretation of a very complex turbiditic system[7].

Figure 4—Neural Connections—The unsupervised neural classification of the basal seismic signature reveals stratal termination patterns not apparent on conventional displays such as the corresponding amplitude map on the left.



Manual seismic facies interpretation was first done in the conventional manner[8] mapping the erosional truncation at the base, and condensed section at the top of the turbiditic system. Four seismic facies were identified based on amplitudes & structural expression. Mapping based on these classes results in the delineation of the sediment fairways and the identification of potential reservoir areas.
The principal problem remaining is mapping the thin, discontinuous reservoirs within the channel/levee & lobe system. Application of automated quantitative seismic facies analysis summarizes the seismic signature in maps and improves the precision in predicting reservoir extent. **Figure 4** compares the amplitude map to the unsupervised, neural-net classification of the 20ms seismic signature above the base, revealing stratal termination patterns not apparent on other conventional displays.
Surface & internal configuration attributes were extracted from the seismic volume—including *amplitude*, *continuity, dip, azimuth, curvature* & *roughness*—and combined & classified with neural-nets. It is important at this stage to assure that the seismic attributes being combined into a prediction model by neural or multivariate statistical methods have physical significance relative to the model; otherwise, combining many meaningless attributes could give an unrealistically high degree of confidence of predictive power[9].
The contribution of the quantified seismic spatial attributes to facies mapping resulted in : *Surface Attributes* showing high & low axes corresponding to sediment transport and faults, and *Interval Attributes* evincing subtle compacted morphologies corresponding to sand prone mounds, and *dip* & *curvature* changes interpreted as braided channels.

INVERSION

Seismically derived acoustic impedance is not a seismic attribute but rather a product of an integration method employing models developed by geophysical theory. There are many methods of inversion, each with varying levels of sophistication and use of non-seismic information: from single trace transforms, to elaborate model based techniques linking geologic realizations and the seismic response to perturbed petrophysical properties.
The algorithm used in the following example is a volumetric, 3D layer inversion that enhances the spatial information inherent in the 3D post-stack volume—information that could be compromised if calibrated too rigorously to well-control. The subtle spatial variations in amplitudes are inverted and constrained globally within a moving sub-volume with flexible layering, thus yielding a high resolution, yet stable, layer framework of acoustic impedance. The resulting volume facilitates interpretation, and can be further post-processed for integration into the reservoir model.

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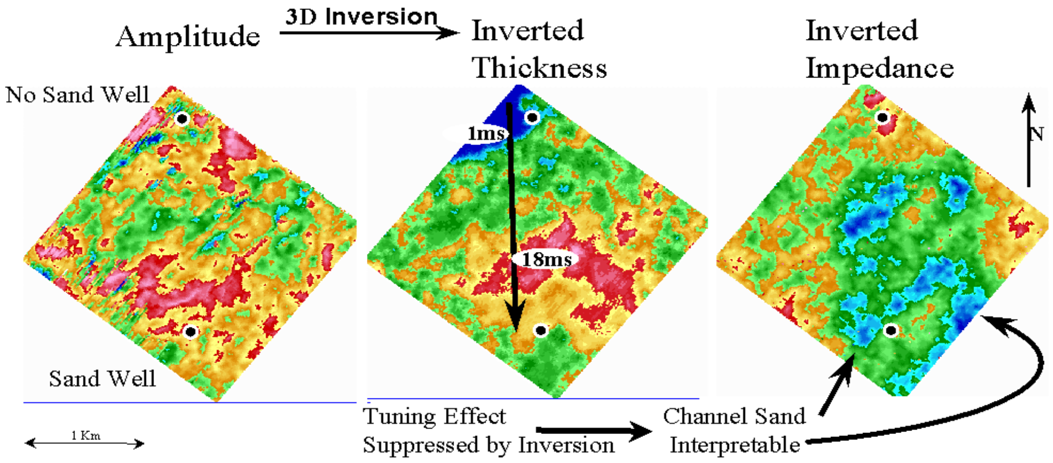

Figure 5—Tuned Out—The **Amplitude** map does not image the channel due to tuning distortion: amplitude changes caused uniquely by **Thickness** changes. 3D Layer Inversion to **Impedance** removes tuning effects rendering an image of the low-impedance (black) channel sands.

Figure 5 is an impressive example showing the power of poststack 3D Layer Inversion to reveal an impedance image of a sand channel not seen by conventional amplitude maps. The objective of this study was the determination of porosity & permeability variations within a series of stacked channel sands.

The two wells used for calibration are posted on the map: the northern No-Sand Well & the southern Sand Well, which encountered a channel sand with some shows of gas. Despite the sand/shale impedance contrast, the amplitude map—"horizon slice" obtained by extracting amplitudes along the automatically determined layering—does not image the channel due to tuning distortion; i.e. amplitude changes caused by layer thickening to the south. 3D Layer Inversion to impedance suppresses tuning effects thereby rendering interpretable the image of the low-impedance channel sands.

4D **SEISMIC**

Oseberg Example. Data from five repeated 3D seismic surveys over the Oseberg Field—1982 vs 1992, 1992 vs 1997 (different acquisition & processing parameters), 1989 vs 1982 (similar processing; different acquisition parameters), 1989 vs 1991 (similar processing & acquisition parameters) and 1989 vs 1992 (similar acquisition; different processing parameters)—were analyzed at the Oseberg formation[10] which experienced 8 years of continuous oil production by 1997. The 1982 vs 1992 and 1992 vs 1997 analysis are summarized below.

The Oseberg Field is located on the Bergen High at the western margin of the Horda Platform in Norwegian seas with a water depth of about 105m. The 82 & 92 surface acquired surveys (streamer, 75m shooting line spacing) and the 97 ocean bottom cable (OBC, 200m shooting line spacing) had approximately the same E-W shooting direction.

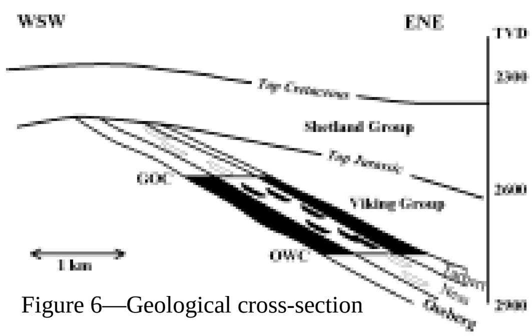

Figure 6—Geological cross-section

Background. The Oseberg formation in the Alpha block has a structural dip of about 8° to the east-northeast, and is comprised of massive, moderate to poorly sorted, coarse-grained deltaic sandstones of the Early to Mid Jurassic Brent Group (**Figure 6**)[11]. Oil production was initiated in December 1988, and by April 1997 about 64% of the expected reserves have been produced[12]. By the end of 1996, all wells in the study area experienced gas breakthrough. At breakthrough, observations in the conventional wells have shown that the height of the gas cone is about 10m. A horizontal well experienced gas breakthrough 1.5-2 years earlier than predicted from the full-field reservoir simulation. The global GOC (gas-oil contact) was monitored to be about 50m above the perforated horizontal well sections.

Rock Physics. During the eight years of production, gas displacing oil is the primary mechanism causing significant change in the Oseberg formation's acoustic impedance and seismic reflectivity—the normal-incidence seismic response has an increase in amplitude due to a 5% reduction in density. With reservoir pressure maintained, it can be assumed that the acoustic impedance of rock surrounding the Oseberg formation remained the same. If pressure is not maintained during depletion then as pore-fluid pressure drops V_p increases, and as gas eventually evolves out of solution V_p decreases.

The slight increase in V_p is caused by the decrease of density offsetting the small decrease of the saturated rock bulk modulus resulting from gas substitution of the relatively stiff framework of the Oseberg formation

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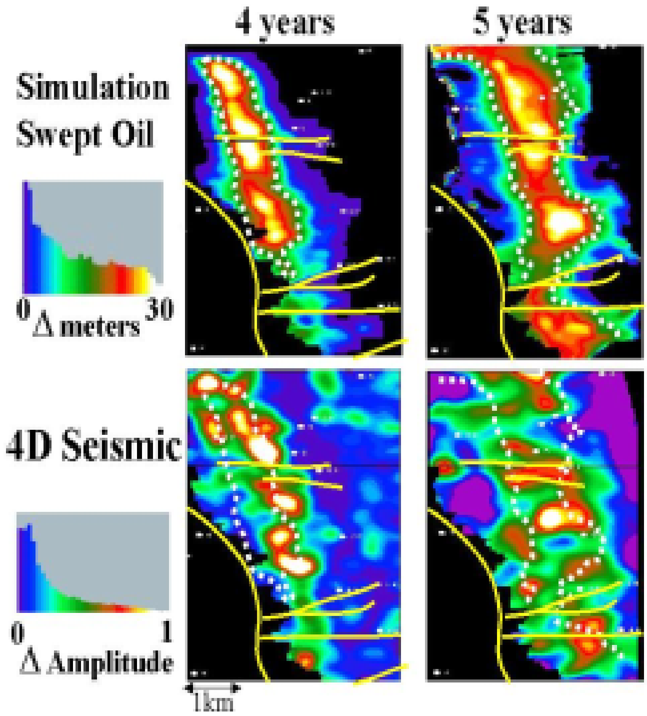
• ***Amplitude.*** There are basically three ways to measure differences between repeated seismic surveys: 1) trace to trace comparison to measure the travel-time difference through the reservoir—related to velocity change; 2) trace to trace comparison of amplitude attributes extracted within an interval—related to acoustic impedance change; and, 3) signature and attribute analysis of the sample-by-sample trace subtraction—related to acoustic impedance change. Since velocity change due to gas displacing oil is insignificant in the Oseberg formation, analysis is restricted to amplitude attribute analysis, and interpretation of the seismic difference volume. Measuring differences of amplitude attributes (2) is more effective than analyzing trace differences (3) because of the greater control of measurement types over an interval, positioning of independent windows, and corrections of amplitude & location can be applied very efficiently.

In addition to measuring attributes within the reservoir interval, attributes are extracted from intervals outside the reservoir where no physical change should have occurred between acquisition times. Applying correction factors to the reservoir attributes are based on minimizing the difference of the attributes outside the reservoir. This is an iterative and interpretive process, and *it is critical that improvement in the differential reservoir image is verified because processes that minimize questionable amplitude differences outside the reservoir may degrade seismic difference information at the reservoir.* This holds equally true for spatially varying cross-equalization processes applied to seismic volumes.

The attribute analysis presented here is the difference in the average absolute value of the interval, • Amplitude.

Reservoir Maps. In **Figure 7** the top maps are estimations derived from the ‘97 history-matched reservoir simulation of the oil column height swept by gas between the times of the seismic surveys : 4 years of production before the ’92 survey; 5 years of production until the ’97 survey. White, 30m swept oil, are areas where most of the Oseberg reservoir has been swept; purple, near 0m, showing estimates of the gas-front progressing towards the right or east, i.e. downdip. Note the volume swept during the last 5 years (Fig 7, right) has moved down dip, toward the east.

Figure 7—Comparison of the estimate of swept oil thickness from reservoir simulation (20m contour copied on seismic maps) with the ΔAmplitude maps.



Below the simulation estimates are the corresponding seismic • Amplitude maps. Swept oil thickness (gas displacing oil) is directly related to positive • Amplitude values (gas – oil). There is generally good agreement between the high positive • Amplitude values and the area of swept oil greater than 20m (20m simulation contour is highlighted on both maps)—the resolution of the seismic data in its current state is apparently 15-20m; increased resolution and reduced uncertainty would require additional 4D seismic reprocessing. These • Amplitude maps were obtained by applying correction factors based on minimizing the amplitude difference outside the reservoir. With only two surveys there is the doubt that amplitude changes are artifacts related to structure—multiple interference, for example—which would be difficult to differentiate from fluid movement. With three surveys confidence is increased in observing that the majority of the seismic differential energy has moved downdip with oil displacement.

The methodologies presented are cost-effective procedures that permit the rapid, but comprehensive construction of a 4D database to support subsequent processing and interpretation. To optimize 4D processing parameters & methodology, and to gauge their cost effectiveness & sensitivity to mapping changes in reservoir properties, it is critical to incorporate analysis of reservoir dynamics & rock physics. Comparative analysis begins by building a reference of the seismic response—seismic attribute maps & 4D model-based classification—related to estimated changes in reservoir properties due to production. Subsequent cross-equalization, position error analysis, and optimization of amplitude transforms can then be efficiently performed with the objective of improving reservoir differential imagery.

CONCLUSIONS

Each reservoir is unique: physically, economically, conceptually—choosing the economically appropriate seismic methods for reservoir characterization requires understanding the complex interrelationships between seismic estimates of reservoir properties.

With the advent of integration ease—providing freedom for creative solutions of the integration problem—comes the potential of relating the myriad sources of inner- and cross-disciplinary data to help gain a better understanding of a reservoir’s current “information state.” This improved understanding allowing then the determination of the technology, cost & time appropriate for the available data and the need for additional data to address reservoir management objectives.

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