2024 GSH Spring Symposium

Honoring

Mike Forrest

Integrated Subsurface Characterization Empowers the Energy Future

March 20-21, Norris Conference Center, Houston, Texas

Morning Session:

8:00 - 8:15 am	Opening / Introductory Note
8:15 - 8:20 am	Session 1 Opener. Moderators: **Katya Casey, Ken Mohn**
8:20 - 9:05 am	Myths, realities, and uncertainties of frontier exploration for deepwater stratigraphic traps and the continued pursuit of improved seismic resolution; a geophysical perspective - **Joe Reilly**
9:05 - 9:50 am	Using geophysical methods to de-risk a frontier deep water basin offshore Somalia – **Marel Sanchez**
9:50- 10:20 am	Break
10:20 -11:05 am	Using Global DHI Learnings and a Calibration Database to Guide Frontier Exploration – **Henry S. Pettingill**
11:05 -11:35 am	Session 1 Panel
11:35 -12:35 pm	Lunch

Afternoon Session:

12:35 - 1:35 pm	Exhibitor Hour
1:35 - 1:40 pm	Session 2 Opener. Moderators: **Hansel Gonzalez, Henry Pettingill**
1:40 - 2:25 pm	Impact of joint seismic amplitude and resistivity interpretation in portfolio evaluation, case example from the Southern North Sea - **Daniel Baltar**
2:25 - 3:10 pm	Improving imaging of subsalt reservoirs through elastic FWI – a case study of the Mars/Ursa fields - **Todd Noble**
3:10 - 3:40 pm	Break
3:40 - 4:25 pm	Carbonate Seismic Reservoir Characterization in Oman: minimizing uncertainty through QI (North) and stochastic attempts in a tight reservoir (South) - **Norbert Van De Coevering**
4:25 - 4:55 pm	Session 2 Panel
4:55 - 5:00 pm	Closing Remarks
5:00 - 7:00 pm	Toast & Roast. Honoree: **Mike Forrest**

Schedule Thursday March 21, 2024

Morning Session:

8:00 - 8:15 am	Opening / Introductory Note
8:15 - 8:20 am	Session 3 Opener. Moderators: **Andrea Crook, Scotty Salamoff**
8:20 - 9:05 am	Leveraging Machine Learning in Suriname Exploration – **Hugo Scherrier, Nommie Kashani, Yen Sun**
9:05 - 9:50 am	Enabling geologically sound high-resolution reservoir characterization through direct probabilistic seismic inversion – **Raul Cova**
9:50- 10:20 am	Break
10:20 -11:05 am	Lithofacies Prediction using Machine Learning (ML) – **Alvaro Chaveste**
11:05 -11:35 am	Session 3 Panel
11:35 -12:35 pm	Lunch

Afternoon Session:

12:35 - 1:35 pm	Challenge Bowl. Organizer: **Wilson Ibanez**
1:35 - 1:40 pm	Session 4 Opener. Moderator: **Lillian Jones, Rocky Roden**
1:40 - 2:25 pm	Subsurface Machine Learning Approaches at Hydrocarbon Recovery and Resource Forecasting for Unconventional Reservoir Systems - **Shane Prochnow**
2:25 - 3:10 pm	Seismic super resolution and its impact on conventional and unconventional field development - **Li Chengbo**
3:10 - 3:40 pm	Break
3:40 - 4:25 pm	Embracing Change: How AI and Deep Learning Enrich Geoscience and Geoscience Enriches AI - **Scotty Salamoff**
4:25 - 4:55 pm	Session 4 Panel
4:55 - 5:00 pm	Closing Remarks

Myths, realities, and uncertainties of frontier exploration for deepwater stratigraphic traps and the continued pursuit of improved seismic resolution; a geophysical perspective

Joseph Reilly

Geoscientists have been successfully exploring for and developing stratigraphically trapped hydrocarbon accumulations for decades.

The main prospective intervals in these deepwater settings typically consist of interbedded sands and shales with varying rock physics responses. The seismically thin pay zones make it challenging to separate individual reservoirs, particularly when they include “hidden overprints” resulting from tuning, overburden, and focusing effects. Reservoir identification is particularly difficult in the early stages of exploration when 2D seismic, gravity, and magnetics may be the only geophysical data available to develop geologic concepts, identify prospects, and evaluate their potential. Critical decisions (acreage acquisition and drilling of the initial exploratory well) are made with significantly lower quality and quantity of data than typically available during the Appraisal and Development phases. As a result, significant physics-based technology “gaps” still exist in these environments.

Notwithstanding some of the above caveats, recent advances in acquisition and processing technologies have clearly resulted in significant improvements in the resolution of seismic images allowing improved identification and characterization of stratigraphic traps at the later Exploration, Appraisal or Development stages. A key goal for the team is to maximize the bandwidth of the seismic data while retaining amplitude fidelity across all offsets/angle ranges with specific attention to irreducible seismic noise that determines the ultimate limit.

We will address the challenges of data availability and confidence, how resolution and data fidelity can be improved (or sometimes, unintentionally compromised) the primary factors controlling bandwidth recovery, and the somewhat subjective, target-oriented decisions commonly required in the real-world. In addition, the importance of visual resolution for interpretation, regardless of the actual data fidelity, will be highlighted.

Data from deepwater Guyana are used to illustrate the above points as well as some of the acquisition, processing, and interpretation workflows that were developed over the history of this project.

About Joseph

Joseph Reilly started his exploration career with Mobil and has over 41 years of industry experience in addressing geoscience challenges throughout the world, recently retiring as ExxonMobil Chief Research Geoscientist. He holds a BSc in Geology from the University of Rochester and an MSc in Geology/Geophysics from Virginia Tech. He is a long-time member of GSH, SEG, EAGE, and AAPG, and is a licensed Geophysicist in the state of Texas.

Using geophysical methods to de-risk a frontier deep water basin offshore Somalia.

Marel Sanchez, Daniel Mujica, Katya Casey

The passive margin of Offshore Somalia was characterized in a regional study which defined opportunities at the play fairway scale in three sub-basins, the Mid-Somalia High, Mogadishu Deep, and Jubba Deep. These basins stretch for more than 1000 km along the coastline and accumulate up to 12 km of sediment from the opening of a rift basin in the early Jurassic to the establishment of a Cretaceous and Tertiary Passive Margin.

The principal geophysical dataset comprised a 20,000 line-km sparse regional 2D survey acquired in 2014, supplemented by gravity and magnetic data. The potential field datasets had limited application due to signal overprinting by multiple phases of the basement and sediment deformation. Geophysical analysis was supplemented by regional geologic models based on onshore studies in Somalia and in the rift-conjugate margin of Madagascar, where an active petroleum system is well-documented. Geophysical analysis was critical in characterizing the carbonate fairway on the Mid-Somalia High (MSH), where studies identified three play fairways. The stratigraphy on the MSH is calibrated by a direct tie on the regional data to the well Meregh-1, drilled in 1982, which penetrated more than 2700 m of Jurassic carbonates at the southern end of an epeiric shelf basin extending up to the Arabian Peninsula. The seismic data were interpreted in time and depth domains and with the aid of some computational seismic attributes used to enhance the imaging of the geology. On a regional scale, vertical trace attributes correlated through the dataset helped to improve geologic interpretation. They enabled the separation of the geologic sequences and correlation with the regional tectonic events in the basin. The computational methods included a review of angle stacks to QC processing, computation of an energy attribute, and spectral decomposition for reservoir and fluid content characterization. Spectral decomposition attributes were particularly effective in highlighting potential reservoir and source intervals, possible gas chimneys, and shallow gas anomalies. These features were also prominent in the Energy attribute.

We conclude that using uncalibrated post-stack seismic attributes in a frontier basin helped to constrain uncertainty in the characterization of the geologic sequences, analysis of petroleum system indicators, and definition of the structural traps. Furthermore, area selection for the planned 3D seismic acquisition was guided by understanding the exploration plays defined on the MSH by this phase of work.

About Marel:

Marel Sanchez has a Master of Science degree in Geophysics and more than 25 years of experience in subsurface characterization as a geoscientist working in fast-paced, result-oriented, multicultural & multidisciplinary project delivery teams. She has strong technical expertise in basin/play/asset evaluation, block/asset acquisition, technology selection and implementation fit to local project conditions, and decarbonization projects. She leads business development and resource characterization projects in Latin America, the Caribbean, and Africa.

Using Global DHI Learnings and a Calibration Database to Guide Frontier Exploration

Henry S. Pettingill, Rocky Roden and Roger Holeywell

DHIs offer a unique de-risking tool when integrated with other geophysical, geological, and petrophysical evaluation techniques.

Rose & Associates' DHI Consortium, has compiled a worldwide 390 well database of drilled DHI prospects. The underlying evaluation workflow employs over 50 objective and observation-driven questions about geological and geophysical DHI characteristics to produce a *calibrated* revised chance of success based on the quality of the DHI.

The science of *Geophysics* is largely basin-agnostic and driven by the laws of physics, so we can compare seismic DHI characteristics from basin to basin. Since AVO (amplitude vs. offset) classes are a predictable consequence of a prospect's geological and geophysical setting, a frontier play or prospect's expected AVO class can usually be predicted, and hence, its risk profile is characterized. For resource assessment, DHIs can effectively constrain trap area, net pay, and porosity to some degree even when minimal well control is available.

Many aspects of *Geology* are specific to a given basin and must be integrated with the seismic analyses of DHIs. Basin-specific aspects of frontier DHI exploration include depositional systems (deposition of source rock, reservoir, and seal), burial, heat flow, trap type, etc. DHI evaluations should also consider quantitative geological analyses such as basin modeling and pore pressure calculations. We will show a few case studies of how the various geophysical and geological techniques are integrated to produce reliable estimates of the uplifted chance of success in frontier DHI prospects, calibrated to our database of drilled DHI prospects. Finally, two recent frontier DHI-supported basin-opening giant discoveries will be discussed, both of which received a large chance of success uplifts with our DHI evaluation methodology.

About Henry:

Henry S. Pettingill is a Petroleum Geologist with over 40 years of experience in the oil and gas industry. His assignments have focused on Deepwater Exploration, International New Ventures, Risk Analysis, and Portfolio Management. He is currently a consultant and Chairman of the Rose and Associates' DHI Consortium. Prior to that, he served as Director of Exploration Technology, Director of Business Innovation, and Chief Geoscientist for Noble Energy. He previously held various technical and managerial positions within Shell and Repsol. Henry was the evaluation geoscientist for several early deepwater discoveries in the U.S. Gulf of Mexico and Northwest Borneo, and he had a direct leadership role in giant discoveries in the Gulf of Mexico, East Mediterranean, and West Africa. Henry has authored over 100 technical papers and conference presentations and has taught numerous field and classroom courses on Deep Water Reservoirs, Risk Analysis, and Creativity and Innovation for E&P.

Mr. Pettingill holds a BA degree from the University of Rochester and an MSc degree from Virginia Tech. He is a Trustee Associate of the SEG and AAPG Foundations.

Impact of joint seismic amplitude and resistivity interpretation in portfolio evaluation, case example from the Southern North Sea

Daniel Baltar

This presentation will conduct a comparative analysis of six different prospects within a shallow gas play located in the Southern North Sea. The focus lies on 4-way dip closures featuring structurally-conforming seismic amplitude anomalies. Utilizing public 3D seismic data, 3D CSEM data, and well data, we aim to comprehensively evaluate these six prospects within the play.

The evaluation will prioritize assessing their risk and volume initially from a seismic perspective and subsequently from an integrated evaluation approach.

From a seismic standpoint, these prospects are interpreted to fall within a similar play segment, sharing very similar risk profiles. Notably, seal integrity poses a significant risk due to the limited burial depth of the targets. However, volume interpretation appears straightforward, supported by a robust seismic amplitude response, structural conformity, and clear delineation of fluid contacts in the seismic data.

The integration of unconstrained CSEM inversion will significantly enhance the evaluation of both the play and individual prospects. This integration promises marked improvements in assessing risk and volume, providing very significant evaluation refinements.

The discussion will extend to exploring potential business implications of incorporating CSEM data into play evaluation. We'll delve into how this integration could influence the exploration strategy, identifying optimal conditions for extracting maximum value from this information. Moreover, we'll consider strategies for integrating it into the work program and delineate the necessary corporate-level conditions for a successful implementation of this technology.

About Daniel:

Daniel Baltar is the Global Interpretation Advisor for EMGS ASA. He has previously been an exploration geoscientist and geophysicist with Repsol. He founded Cycle Petroleum and was its exploration director from 2018 to 2021. He has had a leading role in the integration of EM data into the exploration workflow, starting with Pemex's campaign in the deep-water Gulf of Mexico, the largest CSEM acquisition in the history of the technology. Furthermore, he has developed and published some of the key integration algorithms and workflows bridging exploration performance, play and prospect evaluation, and resistivity rock physics analysis.

Improving imaging of subsalt reservoirs through elastic FWI: A case study of the Mars/Ursa fields

Todd Noble

The Mars/Ursa production corridor overlays a prolific oil basin that recently celebrated 25 years of oil/gas development. Three tension-leg platforms produce numerous turbidite reservoir zones that are developed through both depletion/aquifer drive and active water flooding. Both Mars and Ursa fields have a regular surveillance program of 4D seismic to monitor saturation changes related to aquifer movement and injected water. Despite two decades of seismic imaging and acquisition advances, the surrounding thick, variable salt canopy still poses a challenge for seismic imaging and predicting reservoir properties under and proximal to salt.

Recent advances in acoustic and elastic Full Waveform Inversion (FWI) and the availability of a long-offset sparse-node survey intended for velocity model building prompted an effort to update legacy velocity models in the Mars/Ursa area. Potential uplift in the velocity model ideally translates to better OBN migrations and FWI-derived Images. An acoustic Time-Lag FWI (TLFWI) solution was first applied to the sparse-node data to correct the kinematic velocity errors, but this method suffered from a wide velocity halo zone surrounding the salt and unsatisfactory convergence below the complex salt bodies. In a collaborative effort, a series of tests to improve the FWI results included manual scenario modeling, de-halo, densification of nodes for FWI, and elastic FWI. Ultimately, elastic TLFWI was the selected way forward to reduce the salt-halo and achieve the best subsalt and salt-adjacent imaging, underpinned by improved event focusing at far-offsets, better well ties, a geologically plausible anisotropy field, and reduced residual gather curvature.

The resulting 3D imaging improvements translate directly to 4D image sharpness and quality, revealing previously unseen 4D signals from deeper reservoirs. The elastic FWI Image substantially improves the understanding of deeper salt and sedimentary structures over conventional RTM images.

About Todd:

Todd graduated from the University of Waterloo, Canada with an Honours BSc. degree in Geophysics and from Queen's University in 2004 with an MSc. in Structural Geology. In his 19 years with Shell, he has worked geophysics and leadership roles in Canada, Netherlands, Norway, Malaysia and the US. Arriving in Houston in 2021, he worked as the Mars/Olympus Principal Production Seismologist and transitioned into the Asset Strategic Studies lead role in 2023.

Carbonate Seismic Reservoir Characterization in Oman: minimizing uncertainty through QI (North) and stochastic attempts in a tight reservoir (South)

Norbert Van De Coevering, Jamal Al Aamri

In this presentation, we will see the application of seismic reservoir characterization for carbonates in Oman through two case studies: one in the North and one in the South. In trying to reduce uncertainty of reservoir presence and/or quality, although the settings and outcomes are very different as will be shown, a thorough application of workflows is imperative.

The target formation in the North of Oman is a Cretaceous carbonate rock with a high variation in reservoir quality. Seismic amplitude has been used on several occasions as a good indicator of reservoir quality and sometimes for hydrocarbon saturation. However, it has faced multiple failures when it is not used with care. A thorough amplitude modeling study has shown the reservoir amplitude response to be extremely variable due to variations in thickness, porosity, and saturation of the target interval, as well as variations in the overlying formation. A subsequent rock physics feasibility study showed good differentiation of HC-bearing reservoir from water-bearing reservoir and non-reservoir. Using modern, high-density seismic data, a quantitative interpretation project aimed at overcoming the complex seismic response of the target reservoir was undertaken.

The Thuleilat reservoir in South Oman was discovered in April 2015. It is of Cambrian age, and the lithology is dominated by dolomite and limestone. The depositional environment for these carbonates is shallow to deep marine. The structure is bounded by a series of faults, with the depth of the reservoir around 7700 ft. In most places, there is a thin anhydrite layer above, followed by Ara Salt. Stringers (mostly but not exclusively carbonates) of varying thickness are present in the Salt. The average reservoir permeability is very low. The development takes place largely through horizontal drilling in the Upper Thuleilat. Below, there are thin layers of Intra-Shale, Middle, and Lower Thuleilat before reaching the Al Shomou. With the aim of improving the subsurface model and lowering the risk of future drilling, maximizing recovery, a comprehensive study was undertaken using modern seismic and conditioned logs from twenty (at the time) pilot holes, calibrated to the available core data.

About Norbert:

He graduated from Utrecht University in the Netherlands with a Masters in Geophysics and started his career 27 years ago with CGG in London. Before joining Oxy in Houston in 2016 he worked at Murphy. Currently, he is the Manager of Geophysics Delaware Basin for Oxy after returning from Oman and served as AVOSI Session Chair for IMAGE21 and SEG 2020 Conferences as well as Technical Committee co-chair for the GSH 2023 Spring Symposium. His main interests are in Seismic Data Conditioning and all aspects of Quantitative Interpretation and data integration. He has (co-) authored various publications.

Leveraging Machine Learning for Suriname exploration

Hugo Scherrier, Nommie Kashani, Yen Sun

In this presentation, we illustrate how Machine Learning and Deep Learning techniques address two of TotalEnergies main challenges in the exploration of its operated assets.

The first case study consists in seismic reservoir characterization of Upper Cretaceous turbidites in the prolific Block 58. Due to high variability in rock and fluid properties, quantitative interpretation of seismic response is quite complex. Understanding of trapping mechanism and prediction of reservoir presence and fluid type remains very challenging. Machine Learning, by taking advantage of the large number of exploration and appraisal wells, can better predict reservoir presence from the numerous seismic attributes at hand.

The second case study illustrates the application of deep learning models for seismic post-processing of migrated gathers. Suriname shallow waters are locally affected by Eocene carbonate platform that generates significant converted waves, interbed and surface-related multiples. In-house deep learning models provide reasonable results when compared with conventional post-processing with significantly reduced computational time.

These two case studies demonstrate the ability of machine learning techniques to provide comparable (if not better) results than conventional techniques. Such approaches are expected to become more widely accepted and implemented in the Geosciences community.

About authors:

Hugo is an exploration geophysicist with over 9 years of experience in the oil and gas industry. He holds a Master's degree in Earth Science from ENSG Nancy, France, and a Master's in Petroleum Geophysics from Imperial College, London. Starting his career in Houston in seismic imaging, Hugo has since held various positions in affiliates in Nigeria and Angola, specialising in deepwater field development, seismic interpretation, reservoir monitoring, and drilling various deep water wells.

Nommie Kashani is a Senior Data Scientist working for TotalEnergies Exploration and Production Americas. He has a BS in Information Technology and has 20 years of experience in various areas such as Software Development, Data Analytics and Machine Learning. He has worked for different E&P units of TotalEnergies across the globe, including the Middle East, Africa & Americas.

Yen Sun is a senior research geophysicist at TotalEnergies E&P, where she works on various research projects, including multiphysics joint inversion, global optimization with uncertainty estimation, and developing deep learning tools for subsurface model building and image processing. Prior to her current role, she worked as a postdoctoral fellow at Harvard Medical School and Rice University, where she studied soft matter physics with multidisciplinary approaches. She received her Ph.D. in Physics & Astronomy Department and master’s degree in Geophysics from Rice University.

Enabling geologically sound high-resolution reservoir characterization through direct probabilistic seismic inversion

Raul Cova

Seismic reservoir characterization seeks to improve the understanding of rock properties and reservoir conditions through seismic amplitude analysis. This information is used in all stages of production from exploration to development and monitoring. Accurate reservoir characterization leads to improved well placement and design, helps identify geohazards and is used to help monitor production effects.

AVO inversion is now a commonly applied reservoir characterization technique. It is applied across the industry to various reservoir settings around the world. The connection between the elastic properties from AVO inversion and the underlying rock properties or facies is ambiguous, as various lithology, porosity, and fluid configurations result in similar elastic responses. Adding to this fundamental rock physics issue is the fact that seismic data is band-limited, and as such, the effective elastic response extracted from seismic data is equally represented as either thinly interbedded facies or a single package of their average properties.

Direct probabilistic inversion (DPI) formulates the inversion problem in a Bayesian framework and allows us to use valuable geologic information, previously ignored in standard deterministic AVO inversions, to help mitigate these fundamental ambiguities. We present three case studies where DPI was applied to address different reservoir characterization challenges. From computing facies and surfaces probabilities, to dealing with both weak and strong elastic responses in thin-bed settings, these case studies illustrate how infusing more geological information in the inversion problem can lead to more accurate and geologically consistent inversion results. Additionally, since DPI outputs the full posterior probability distribution for each facies, it allows to explore P10, P50 and P90 solutions that can be used for further risk analysis and a more complete assessment of exploration and production scenarios.

The case studies that will be presented include an unconventional reservoir characterization from the Cooper Basin in Australia (Cova et al., 2020), a thin-bedded sequence characterization from Southern Alberta (Mutual et al., 2021) and an anisotropic DPI study performed over a reservoir in the East Coast of Canada using offshore data (Cova et al., 2023).

About Raul:

Raul Cova received his B.Sc. Degree in Geophysics in 2004 from Simon Bolivar University in Venezuela. Between 2004 and 2012 he worked for PDVSA where he occupied different roles related to seismic data acquisition, processing, and interpretation. He obtained his PhD degree at the University of Calgary in 2017 where he was a fellow of the CREWES consortium. He continued at the University of Calgary as a Postdoctoral Researcher working on full-waveform inversion problems. Raul joined Qeye in Calgary in 2019, where he is now a Lead Geophysicist specializing in pre-stack seismic inversion and advanced reservoir characterization techniques.

Machine Learning for Lithofacies Prediction – a Fast, High-resolution, and Economic Alternative to Seismic Inversion

Alvaro Chaveste

A methodology for lithofacies prediction is presented. It is based on computing Self Organized Maps (SOM), an unsupervised form of Machine Learning (ML), and cross-referencing the results to lithofacies from petrophysical logs. The methodology defines the lithofacies of interest with improved resolution and significant time savings when compared to inversion-based reservoir characterization.

Unlike seismic and petrophysical inversions, the proposed methodology is not deterministic. It computes SOM from a user-defined number of seismic attributes. The process' multi-dimensionality (each attribute is a dimension) reduces the non-uniqueness associated with seismic and petrophysical inversions. SOM classifies several attributes sample by sample (same sample for all attributes) and assigns a cluster (neuron) to each time/depth sample. This results in interpretable data below the wavelet's limit of resolution.

The assignment of geologically meaningful labels to SOM neurons is done by cross-referencing neurons from seismic to lithofacies computed from the wells' petrophysical evaluation. By matching neurons to lithofacies at the same depth, the process assigns a label to each neuron that indicates the most likely rock type. This way, we can use the SOM neurons to map the distribution and variation of the lithofacies in the subsurface.

The methodology does not require wavelet estimation or a low frequency model; thus, easing processing and interpretation requirements.

A case study in the Niobrara formation is presented to illustrate the methodology (Chaveste et al, 2023). The petrophysical evaluations in five wells are used to create four lithofacies. The lithofacies, computed using K-Means, are cross-referenced with a 64-neuron SOM in which eight seismic attributes are input to the calculation. The result is a 3D volume of lithofacies that matches the analysis wells has aerial continuity, shows reliable data at a fraction of the wavelet's limit of resolution, and provides a value of the probability of occurrence at each seismic sample.

A second case study in East Texas illustrates facies definition in clastic sediments. In this case, lithofacies' thickness is below the wavelet's limit of resolution and discontinuous.

About Alvaro:

Alvaro Chaveste is a senior geophysical adviser at Geophysical Insights in Houston. He has worked extensively with seismic data acquisition, rock physics, anisotropy, data processing, quantitative interpretation, and machine learning. Before joining the company in 2022, Chaveste served as manager of the advanced reservoir geophysics group at Core Laboratories, director of interpretation at Geokinetics, and senior geophysical adviser in Hess Corp.'s technology group. He holds a B.S. in geophysics from Montana Technology University and has done graduate studies at the University of Houston.

Subsurface Machine Learning Approaches at Hydrocarbon Recovery and Resource Forecasting for Unconventional Reservoir Systems

Shane Prochnow

This presentation is a survey of subsurface machine learning concepts that have been formulated for unconventional asset development, described in the literature, and subsequently patented. Operators that utilize similar subsurface machine learning workflows and other data modeling techniques enjoy a competitive advantage in optimizing the development of unconventional plays. For example, this advantage has allowed Chevron to book 3.3 MMBOE net resource (P4-P6) adds while saving an estimated $500MM in exploration well costs from 2020-2021. The value benefits increase as subsurface machine learning is applied beyond Exploration and into Development and Enhanced Oil Recovery (EOR) activities. These workflows typically guide practitioners from data gathering to geospatial assembly, quality control and ingestion, then on through machine-learning feature selection, modeling, validation, and acceptance for results reporting. The ultimate products of these workflows can be visualized in both map or log (depth) space to help identify key regions for well optimization or landing zones, respectfully. Machine-learned algorithms that forecast production from engineering, development, reservoir, and geologic predictors in unconventional plays can be further interpreted to derive optimization practices for well development and operations. A workflow is described that spatially optimizes completions in the subsurface to ensure that unconventional reservoirs are properly stimulated for maximum recovery. Additionally, innovations are described that use data-driven methods to better estimate recovery factors for unconventional reservoirs. The geostatistical, spatial, and non-parametric statistical approaches used in conjunction with subsurface machine learning workflows are discussed for their utility in understanding the geographic extent of well-trained production forecasts from data models, including applications for testing the viability of type-curve neighborhoods. These data-driven workflows also ultimately serve to characterize often multidimensional trends and non-linear interactions between key predictors that are useful for building a deeper understanding of the critical physical processes active in the subsurface that influence unconventional good productivity and profitability.

About Shane:

Shane Prochnow is a digital geology advisor at the Chevron Corporation Technology Ventures unit. Prochnow earned his master’s in 2001 and his doctorate in 2005 in geology from Baylor University and continued to complete three years of post-doctoral research there before moving on to the energy industry. He first joined ExxonMobil in 2008 working several roles in the Upstream Research Company. He then joined Chevron in 2012, specializing in shale and tight reservoir Development by taking on roles in both business units and in research. He has published numerous articles and formulated 15 patents on the application of machine learning and data science for subsurface unconventional development. Prochnow is a military veteran and a Texas cattle rancher and an Alaskan homesteader in his off time.

Seismic super-resolution and its impact on conventional and unconventional field development

Chengbo Li

Seismic data plays a pivotal role in exploration and development, with its resolution being crucial for accurate stratigraphic and structural interpretations. The anelastic effect of wave propagation tends to attenuate higher frequencies, leading to seismic data that is inherently band-limited. This limitation often results in interpretative ambiguities for thin reservoirs or complex geological structures.

Drawing on the previous work of Chopra et al. (2006) and Puryear and Castagna (2008) on reflectivity inversion, we introduce a Seismic Super Resolution (SSR) method that integrates principles from both computer vision and geophysics. In image processing, super-resolution aims to create high-resolution images from their low-resolution counterparts. Shi et al. (2015) proposed a single-image super-resolution technique using total variation regularization, achieving promising results in medical imaging. This approach is particularly suitable for seismic data, as total variation regularization promotes locally homogeneous structures, aligning well with the layered character of the subsurface. Our proposed method involves simultaneously regularizing reflectivity and acoustic impedance models by exploiting their sparsity and local homogeneity. In our method, well data is excluded from the optimization to avoid introducing bias at the early stages of inversion.

Since its initial development in 2021, the SSR method has shown considerable success in assisting field development, including improvements in well planning, reducing drilling uncertainties, and better reservoir delineation. We here discuss case studies from both conventional and unconventional fields to demonstrate the benefits of this method.

About Chengbo:

Chengbo Li, a mathematician and geophysicist, graduated from Nanjing University and obtained his Master and Ph.D. from Rice University. At ConocoPhillips, his expertise in compressive sensing and optimization led to the development of the proprietary Compressive Seismic Imaging (CSI) technology. He also led the efforts in developing machine learning solutions for seismic processing and fiber optic sensing for inwell monitoring. Li's contributions in geophysics have been recognized with several prestigious awards, including the SEG Reginald Fessenden Award in 2021 and the Edith and Peter O'Donnell Award from the Academy of Medicine, Engineering and Science of Texas (TAMEST) in 2023. He has also held influential positions in various committees and boards, serving the geophysics community.

Embracing Change: How AI and Deep Learning Enrich Geoscience and Geoscience Enriches AI

Scotty Salamoff

Energy companies are rushing to Artificial Intelligence (AI)-enabled technologies to cut costs and drive exploration without a full understanding of the best practices in using the technology, or at times flawed or no understanding of what AI is at all. An inordinate amount of effort is spent coming up with reasons not to use AI-enabled workflows, perhaps more effort than it would take to learn how to use a new type of software and think about data in a new way.

Rather than resist these massive changes and invest a huge amount of energy convincing ourselves and others that AI tools add no value and *do not* belong in interpretation, we, as geoscientists, should embrace them and find ways they *do belong* in interpretation.

Implementing AI-assisted methods in your subsurface interpretation workflow will only succeed if there is a high-level but complete understanding of what AI is, what it can (and can't) do, and when it's appropriate to use it in subsurface interpretation workflows. AI algorithms are as varied as the methods used to employ them; however, they all share one thing in common – the goal of letting you do more with less. AI methods allow you to update earth models in near-real time and eliminate interpretation waste (the inevitable byproduct of traditional modeling). Therein lies our opportunity. If we are to reap the benefits of AI technology, we must correctly understand and wisely implement and deploy it. We are responsible for what information we choose to train networks on, and how the valuable outputs that come from deep learning are interpreted in real-world scenarios. AI isn't a dogma, nor is it an omnipotent solution to all the interpretation problems we face. It's a living, evolving asset that, when deployed and used correctly, delivers a significant positive impact on interpretation turnaround time and the time we spend doing actual geoscience rather than repetitive interpretation or data-management-oriented tasks.

About Scotty:

Scotty is the global Geoscience Product Manager at Bluware, a CMG company, where he directs the development and deployment of integrated interactive deep-learning software solutions for subsurface mapping and other E&P activities. He started his career at Chevron, where he held many geophysical roles in a broad spectrum of business and research units. In 2012 he moved into consulting, which he did for two years before joining Noble Energy in 2014. In January 2018, Scotty left Noble to work with ActusVeritas Geoscience and joined Bluware in 2019 as a QA engineer and geoscience SME.

His current focus is on developing "5th-generation" interpretation solutions for geoscientists, which will leverage the best of the geo- and data-science worlds to eventually replace the antiquated interpretation applications widely in use today. Scotty is a huge proponent of the responsible use of machine learning and data-centric seismic interpretation methods.