British Journal of Earth Sciences Research, 14(1),73-95, 2026
Print ISSN: 2055-0111 (Print)
Online ISSN: 2055-012X (Online)
Website: https://www.eajournals.org/
Publication of the European Centre for Research Training and Development -UK

From Prospect Ranking to Capital Allocation: Integrating 2G&R Synthesis and Uncertainty Analysis in Deepwater Salt-Tectonic Exploration

Edidiong Edidiong-Umoh
M.Sc Petroleum Geosciences, University of Manchester

doi: https://doi.org/10.37745/bjesr.2013/vol14n17395 Published January 31, 2026

Citation:Edidiong-Umoh E. (2026) From Prospect Ranking to Capital Allocation: Integrating 2G&R Synthesis and Uncertainty Analysis in Deepwater Salt-Tectonic Exploration, *British Journal of Earth Sciences Research*, 14(1),73-95

Abstract: *Deepwater salt-tectonic basins represent some of the most material remaining exploration opportunities globally, offering the potential for giant discoveries while simultaneously imposing exceptional technical and financial risk. Despite significant advances in subsalt imaging, play-based exploration, and probabilistic resource assessment, a persistent disconnect remains between sophisticated geoscientific evaluation and the binary, capital-intensive investment decisions that ultimately govern exploration outcomes. Too often, uncertainty is either oversimplified or poorly translated into portfolio-relevant metrics, limiting the ability of technical insight to meaningfully influence capital allocation.This paper presents an integrated, decision-focused framework designed to bridge that gap. The approach systematically links Geology, Geophysics, Geochemistry, and Reservoir (2G&R) synthesis with formal uncertainty quantification, prospect ranking, and portfolio-level economic evaluation. Central to the methodology is a sequential, closed-loop workflow that begins with Common Risk Segment (CRS) mapping to preserve geological dependencies across prospects, propagates subsurface uncertainty through probabilistic volumetric analysis using Monte Carlo simulation, and translates volume distributions into risked economic metrics under multiple price scenarios. These outputs are then aggregated at the portfolio level to guide capital allocation decisions, including seismic acquisition, block ranking, and partner alignment.The framework is demonstrated through application to a deepwater U.S. Gulf of America case study characterized by complex allochthonous salt tectonics, limited well control, and competing demands for exploration capital. Results show that the integrated workflow produced a materially different prospect and block ranking compared to traditional volume-led or heuristic approaches. Most notably, a formal Value of Information analysis quantified the probability that uncertainty reduction would generate economic uplift exceeding cost, directly supporting the sanctioning of a multi-million-dollar ocean-bottom node (OBN) seismic program. The same portfolio logic informed block prioritization for an upcoming license round and provided transparent risk–reward visualizations that enabled partner-aligned investment decisions.The study demonstrates that formalizing the geoscience-to-investment workflow is not an academic exercise, but a practical necessity for capital efficiency and decision quality in frontier and deepwater exploration. By preserving geological fidelity while embedding economic relevance, the framework transforms subsurface evaluation into a strategic planning tool, offering a replicable pathway for disciplined exploration of the world's remaining complex* hydrocarbon resources.

KEYWORDS: *Deepwater exploration; Salt tectonics; 2G&R synthesis; Common Risk Segment mapping; Uncertainty analysis; Probabilistic volumetrics; Prospect ranking; Capital allocation; Value of Information; Ocean-bottom node seismic*

INTRODUCTION

Deepwater salt-tectonic basins occupy a singular position in the global upstream portfolio. Provinces such as the U.S. Gulf of America, offshore Brazil, and West Africa have repeatedly demonstrated their capacity to deliver material, often company-making discoveries, underpinned by thick sedimentary sections, world-class source rocks, and highly efficient salt-controlled trapping architectures. At the same time, these settings are among the most capital-intensive and technically unforgiving domains in the petroleum industry. Individual exploration wells routinely exceed several hundred million dollars in fully loaded cost, while enabling datasets—most notably wide-azimuth and ocean-bottom node (OBN) seismic—require multi-year commitments and nine-figure investments before a single well is spudded. In this context, subsalt imaging uncertainty, structural complexity driven by salt kinematics, variable trap integrity, and the ever-present risk of reservoir absence combine to create a risk–reward envelope that is both extraordinary and opaque.

The industry has responded to these challenges with increasingly sophisticated geoscience workflows. Advances in seismic acquisition and processing, coupled with integrated Geology, Geophysics, Geochemistry, and Reservoir (2G&R) studies, have materially improved subsurface understanding. Detailed play-based evaluations, calibrated charge modeling, probabilistic volumetrics, and structured uncertainty analysis are now standard practice in most deepwater organizations. Yet, despite this technical maturity, a persistent and consequential disconnect remains. The final investment decisions—whether to drill or defer, to acquire or relinquish acreage, to sanction a seismic program or redeploy capital elsewhere—are ultimately binary and portfolio-driven. They are made under capital constraints, partner alignment considerations, and corporate risk tolerance that are not always transparently linked to the underlying geoscientific assessments.

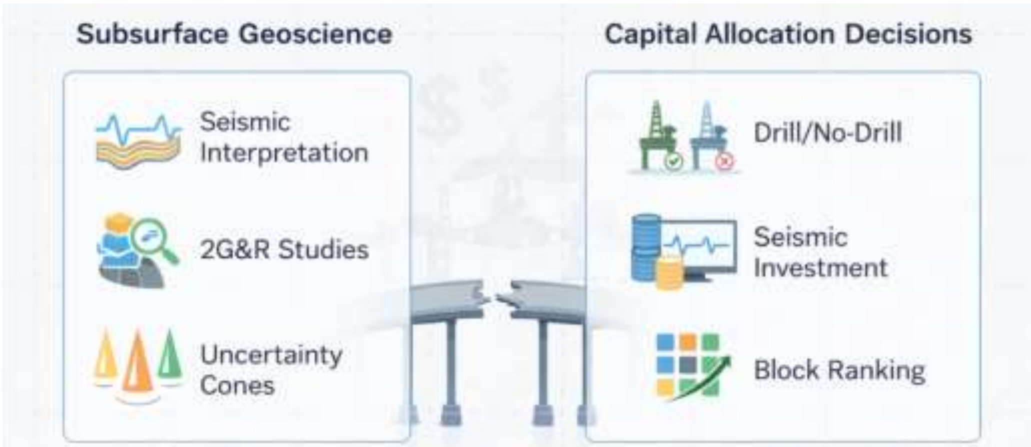

Figure: Conceptual illustration of the decision gap between subsurface geoscience analysis and capital allocation in deepwater exploration.

This disconnect constitutes a critical decision gap in deepwater exploration. On one side of the gap sits an abundance of high-resolution technical insight: fault-seal analyses refined to individual stratigraphic intervals, amplitude-supported reservoir fairways, and probabilistic distributions of hydrocarbons-in-place derived from rigorous uncertainty frameworks. On the other side sit capital allocation decisions that must compare fundamentally dissimilar opportunities—often across plays, basins, or even business units—using a common economic currency. Too frequently, the translation between these two domains is informal, subjective, or relegated to late-stage screening exercises. As a result, technically elegant subsurface evaluations may exert only marginal influence on portfolio ranking, while investment committees are left to reconcile competing narratives rather than comparable, decision-ready metrics.

The consequences of this gap are nontrivial. Capital may be deployed toward prospects whose technical risks are poorly differentiated, while higher-quality opportunities are deferred due to misaligned perceptions of uncertainty. Seismic investments, particularly OBN surveys, may be justified on qualitative grounds without a clear articulation of how uncertainty reduction translates into value creation across a portfolio. Conversely, acreage relinquishment decisions may be made without fully capturing the option value embedded in technically credible but immature opportunities. In aggregate, these inefficiencies erode capital discipline and obscure the true risk-adjusted potential of deepwater portfolios.

While most organizations acknowledge the importance of integrating geoscience and economics, existing approaches often stop short of a formal, iterative linkage. 2G&R synthesis and uncertainty analysis are commonly treated as inputs to prospect maturation, after which economic modeling and ranking proceed largely independently. Risk factors may be simplified into single-point chance-of-success estimates, and volumetric uncertainty may be compressed into mean or P50 outcomes that inadequately reflect the tails of the distribution. Crucially, the geological rationale underpinning these metrics is seldom preserved in a way that allows transparent comparison across prospects or meaningful dialogue with partners and decision-makers.

This paper addresses that gap directly. Its objective is to present a coherent, publication-ready framework that explicitly links subsurface technical evaluation to capital allocation decisions in deepwater salt-tectonic exploration. The framework is designed to be iterative rather than linear, enabling continuous feedback between geoscientific interpretation, uncertainty quantification, and portfolio-level ranking. Using a U.S. Gulf of America case study, the paper demonstrates how disciplined 2G&R synthesis can be translated into investment-relevant metrics that guide not only drill-or-drop decisions, but also strategic choices around seismic acquisition, block prioritization, and partner alignment.

At the core of the approach is the concept of Common Risk Segment (CRS) mapping within a 2G&R context. Rather than treating prospects as isolated entities, CRS mapping delineates shared geological risk elements—such as charge access beneath salt canopies, reservoir presence within stratigraphic fairways, or trap integrity across structural domains—at the play and sub-play scale. This allows uncertainty to be characterized coherently across multiple prospects, preserving geological consistency while enabling meaningful aggregation at the portfolio level.

Building on this foundation, the framework employs a quantitative conversion of uncertainty into volumetric outcomes. Probabilistic distributions of reservoir, trap, and charge parameters are propagated into recoverable volume ranges that explicitly capture both upside potential and downside risk. These distributions are not ends in themselves; they form the basis for a portfolio-ranking engine that integrates technical risk, volume uncertainty, and economic value under consistent assumptions. Importantly, the methodology retains traceability back to the underlying geoscience, allowing decision-makers to interrogate not just the numbers, but the geological judgments that drive them.

The practical utility of the framework is illustrated through its direct application to OBN seismic acquisition and block ranking decisions in the Gulf of America. By quantifying how incremental seismic investment reduces specific elements of geological uncertainty across a CRS, the approach enables a value-based justification for seismic spend that is aligned with portfolio priorities and partner expectations. In doing so, it reframes seismic not as a discretionary technical enhancement, but as a capital allocation decision grounded in measurable risk reduction and value uplift.

In positioning geoscience as an active driver of investment strategy rather than a precursor to it, this paper argues for a more integrated decision culture in deepwater exploration. Bridging the decision gap between subsurface insight and capital deployment is not merely an analytical exercise; it is a prerequisite for sustaining capital efficiency and strategic clarity in the next generation of deepwater ventures.

LITERATURE REVIEW

A Synthesis of Disconnected Domains

The intellectual foundations underpinning deepwater salt-tectonic exploration are both extensive and mature. Over the past four decades, the industry has produced a rich body of literature addressing (i) the geological and geophysical complexities of salt basins, (ii) analytical methods for uncertainty quantification and prospect ranking, and (iii) portfolio management and capital allocation in exploration and production (E&P). However, these strands have largely evolved in parallel rather than in concert. This review is structured deliberately as a synthesis of these disconnected domains, establishing the technical depth of each while highlighting the persistent lack of integration that motivates the framework presented in this paper.

Technical Foundation: Salt Tectonics and Prospect Evaluation

Salt-tectonic provinces have long been recognized as uniquely prolific yet inherently complex hydrocarbon systems. Seminal work on salt deformation mechanics established the fundamental behaviors of halite as a viscous, mobile medium capable of flowing under differential loading, generating diapirs, allochthonous canopies, minibasins, and complex weld geometries. Early conceptual models by Trusheim, Jackson and Talbot, and later refined kinematic and mechanical frameworks by Hudec, Jackson, and Rowan provided the basis for understanding how salt movement controls trap formation, sediment routing, and structural compartmentalization in deepwater settings. These studies remain central to modern exploration thinking in the Gulf of America, offshore Brazil, and West Africa.

As exploration progressed into increasingly subsalt domains, the limitations of seismic imaging beneath complex salt geometries became a dominant theme in the literature. Numerous studies documented the challenges associated with velocity model building, ray-path distortion, and illumination shadows beneath thick or rugose salt bodies. The evolution from narrow-azimuth to wide-azimuth and full-azimuth seismic acquisition, coupled with advances in depth imaging, anisotropic velocity modeling, and reverse time migration, has been extensively documented as a step-change in subsalt interpretability. More recently, ocean-bottom node (OBN) seismic has been positioned in the literature as a further escalation in imaging fidelity, particularly for presalt objectives and deeply buried subsalt reservoirs. Yet, even these advances are consistently framed as uncertainty reduction rather than uncertainty elimination, reinforcing the probabilistic nature of subsalt prospect evaluation.

Beyond imaging, salt basins present persistent challenges in predicting the presence and quality of reservoirs and the effectiveness of hydrocarbon charge. Stratigraphic complexity associated with ponded turbidite systems, salt-withdrawal minibasins, and evolving sediment fairways has driven a substantial body of work on depositional systems analysis in salt-influenced settings. Authors have emphasized the importance of integrating seismic geomorphology, analog calibration, and basin modeling to constrain reservoir presence risk. Similarly, charge evaluation beneath salt has been a recurring focus, with studies highlighting the sensitivity of charge access to salt weld integrity, fault connectivity, and timing relationships between trap formation and hydrocarbon generation.

In response to these multi-dimensional risks, the industry increasingly adopted play-based exploration (PBE) methodologies. PBE reframed exploration from isolated prospect hunting to systematic evaluation of geological plays, emphasizing common risk elements shared across multiple prospects. Within this context, the concept of Common Risk Segment (CRS) mapping emerged as a powerful tool to spatially delineate shared geological risks—charge, reservoir, trap, and seal—at a play or sub-play scale. CRS mapping allowed geoscientists to articulate risk in a way that was internally consistent across prospects, enabling comparative evaluation and learning as wells were drilled. While CRS concepts are well established in the technical literature and widely applied in practice, their use has largely remained confined to geoscience teams, with limited formal linkage to economic ranking or portfolio decision-making.

Analytical Methods: Uncertainty Quantification and Prospect Ranking

Parallel to advances in geological understanding, the industry has developed a sophisticated analytical toolkit for quantifying uncertainty and ranking exploration opportunities. The probabilistic treatment of hydrocarbons-in-place and recoverable volumes is now codified through frameworks such as the SPE Petroleum Resources Management System (PRMS). PRMS formalized the use of probabilistic distributions for key volumetric parameters—area, thickness, porosity, saturation, and recovery factor—and established standardized terminology for reporting low, best, and high estimates. This probabilistic mindset represented a critical shift away from deterministic point estimates toward explicit recognition of subsurface uncertainty.

Monte Carlo simulation became the dominant computational approach for propagating parameter uncertainty into volumetric and economic outcomes. Numerous studies demonstrated the value of Monte Carlo methods in capturing non-linear interactions between geological variables and in preserving the shape of outcome distributions, particularly the tails that often dominate exploration value. Decision tree analysis further extended these concepts by incorporating sequential decision points, allowing exploration teams to evaluate staged investments, appraisal options, and farm-in or farm-out scenarios.

Prospect ranking methodologies evolved alongside these probabilistic tools. Expected Monetary Value (EMV) emerged as a foundational metric, combining chance of success, risked volumes, development costs, and commodity prices into a single scalar measure of value. Variants such as Risked Present Value (RPV) and Expected Net Present Value (ENPV) sought to refine EMV by incorporating time value of money and development phasing. More recent literature explored portfolio-level metrics, including value-at-risk (VaR) and capital efficiency ratios, as ways to assess not just individual prospects but the aggregate behavior of exploration portfolios.

Despite their analytical rigor, these methods have been subject to sustained critique. Authors have noted that EMV-based rankings can be highly sensitive to subjective inputs, particularly chance-of-success estimates that mask underlying geological dependencies. Others have highlighted the tendency for volumetric uncertainty to be compressed into mean values for ranking purposes, effectively discarding information about upside potential and downside exposure. Importantly, several studies have emphasized that probabilistic rigor does not guarantee decision relevance if the outputs are not aligned with how capital is actually allocated within organizations.

A recurring theme in this body of literature is the challenge of translating geoscientific uncertainty into decision-ready economic metrics without oversimplification. While probabilistic volumetrics and decision analysis are well developed, their application often occurs after geological evaluation is effectively "complete," reinforcing a sequential rather than integrated workflow. The literature largely stops short of demonstrating how geological risk segmentation, uncertainty propagation, and economic ranking can be operationalized together in real exploration decisions, particularly in complex salt-tectonic settings.

Strategic Context: Portfolio Management and Capital Allocation in E&P

The third strand of relevant literature addresses portfolio management and capital allocation in the E&P sector. Drawing initially on financial portfolio theory, early studies advocated diversification across plays, basins, and fiscal regimes to manage exploration risk. These concepts were adapted to upstream realities, recognizing that geological risks are often correlated rather than independent, particularly within a single play or province.

The industry's approach to portfolio management underwent a pronounced shift following the oil price collapse of 2014. A growing body of literature emphasized capital discipline, returns-focused exploration, and the concept of "capital efficiency" as a primary performance metric. Exploration was increasingly evaluated not on volumes added alone, but on value delivered per dollar invested and on its ability to compete for capital against short-cycle opportunities such as shale developments.

Within this strategic context, the value of information (VOI) emerged as a key analytical concept. VOI frameworks sought to quantify whether additional data—most notably seismic—justified their cost by reducing uncertainty and improving decision outcomes. Studies demonstrated how VOI could, in principle, guide decisions on seismic acquisition, reprocessing, or appraisal drilling. However, much of the published work treated VOI in abstract or stylized settings, with limited illustration of how it is applied in live, partner-constrained deepwater exploration programs.

In practice, capital allocation decisions in deepwater portfolios are influenced by a complex interplay of technical merit, economic ranking, partner alignment, and strategic positioning. The literature acknowledges these realities but often addresses them qualitatively. There remains a notable scarcity of published case studies showing how geoscientific assessments directly informed multi-million-dollar seismic investments, block ranking, or acreage management decisions in a transparent, repeatable manner.

Synthesis and Identification of the Gap

Taken together, these three strands of literature—salt-tectonic prospect evaluation, uncertainty quantification and ranking, and portfolio-level capital allocation—demonstrate a high degree of maturity when considered individually. The industry possesses robust geological models for salt basins, well-established probabilistic and economic tools, and an increasingly sophisticated understanding of portfolio management under capital constraints.

What is conspicuously absent, however, is a practical, published framework that operationalizes their integration. The technical literature rarely extends beyond prospect-level evaluation into portfolio decisions. Analytical studies often abstract away geological specificity. Strategic discussions of capital allocation frequently rely on simplified representations of subsurface risk. This fragmentation is particularly acute in salt-tectonic settings, where geological dependencies across prospects and the scale of capital exposure demand a more tightly coupled geoscience-to-investment workflow.

The gap, therefore, is not one of technical capability but of integration and execution. There is a paucity of documented methodologies that preserve geological fidelity while translating uncertainty into portfolio-relevant metrics that can guide seismic acquisition, prospect ranking, and partner-aligned capital allocation in real time. Addressing this gap is the central contribution of the present study, which seeks to connect these mature but disconnected domains into a coherent, decision-focused framework grounded in deepwater salt-tectonic exploration practice.

METHODOLOGY

A Sequential, Closed-Loop Geoscience-to-Investment Workflow

The methodology presented in this study is designed explicitly to bridge subsurface technical evaluation and capital allocation through a sequential, closed-loop workflow. Rather than treating geoscience, uncertainty analysis, and economics as discrete handoffs, the framework integrates them through decision-gated phases, allowing insights generated at each stage to iteratively refine both technical understanding and investment strategy. Conceptually, the workflow can be visualized as a flowchart in which each phase feeds forward into the next, while key decision points enable feedback loops that recalibrate assumptions, prioritize data acquisition, or re-rank opportunities as new information emerges.

Textually, the process begins with integrated 2G&R synthesis and Common Risk Segment (CRS) mapping, advances through probabilistic volumetric and uncertainty analysis, transitions into prospect-to-portfolio economic ranking, and culminates in explicit capital allocation guidance. Crucially, outcomes from the latter phases inform whether and how the workflow is re-entered, particularly through targeted seismic acquisition or portfolio reshaping decisions.

Figure: Sequential, closed-loop workflow linking 2G&R synthesis to portfolio-level capital allocation decisions.

Phase 1: Integrated 2G&R Synthesis and Common Risk Segment Mapping

The first phase establishes the geological and geophysical foundation of the framework. Integrated 2G&R synthesis is undertaken at both prospect and play scales, ensuring that individual prospect evaluations remain anchored within a coherent regional context. Geological interpretation focuses on trap definition, structural evolution, and reservoir architecture, with particular emphasis on salt-related deformation styles, weld development, and minibasin stratigraphy. These elements are interpreted in a time- and depth-consistent framework to preserve kinematic and depositional plausibility.

Geophysical analysis centers on subsalt imaging fidelity and attribute-based reservoir prediction. Seismic interpretation incorporates multiple realizations of velocity models to explicitly acknowledge imaging uncertainty beneath complex salt geometries. Seismic attributes, spectral decomposition, and amplitude-versus-offset behavior are evaluated probabilistically, not as deterministic indicators, to inform reservoir presence and quality risk. Where applicable, pre-stack depth migration sensitivity analyses are used to bound structural uncertainty associated with salt velocity assumptions.

Geochemical evaluation provides the charge and timing constraints necessary to complete the petroleum system assessment. Basin and petroleum system models are constructed or updated to evaluate source rock maturity, expulsion timing, migration pathways, and trap-charge access, with explicit consideration of salt weld integrity and fault connectivity. Outputs from these models are not reduced to binary charge/no-charge outcomes; instead, they are used to define gradational charge risk across the play.

These disciplinary inputs are synthesized through Common Risk Segment mapping. CRS maps delineate spatial domains that share common geological risk characteristics for charge, reservoir, and trap/seal. Each CRS is assigned risk descriptors that are internally consistent and traceable to the underlying 2G&R interpretations. The result is a risk-weighted geologic model that captures dependencies among prospects and provides the structural backbone for subsequent uncertainty quantification.

Phase 2: Probabilistic Volumetric and Uncertainty Analysis

Building on the CRS-defined geological framework, Phase 2 formalizes subsurface uncertainty through probabilistic volumetric analysis. For each prospect, key volumetric parameters—including area, net reservoir thickness, net-to-gross ratio, porosity, hydrocarbon saturation, and recovery factor—are defined as probability distributions rather than single-point estimates. Parameter ranges are grounded in seismic interpretation, analog data, and CRS-level geological understanding, ensuring consistency across prospects within the same play segment.

Distribution types (e.g., triangular, lognormal) are selected based on the nature of the uncertainty and the availability of calibration data. Importantly, dependencies between parameters—such as area and thickness within confined minibasins—are explicitly considered to avoid artificial inflation or suppression of volumetric outcomes. Charge and trap risks are incorporated through conditional probabilities linked to CRS attributes, preserving geological causality.

Monte Carlo simulation is then used to propagate these uncertainties into probabilistic distributions of hydrocarbons-in-place and recoverable volumes. The outputs are expressed as full probability density functions, from which standard percentiles (P90, P50, P10) are extracted for reporting and comparison. These distributions retain critical information about skewness and tail behavior, which is essential for understanding both upside potential and downside exposure in high-impact deepwater exploration.

Phase 3: Prospect-to-Portfolio Economic Ranking

In Phase 3, volumetric uncertainty is translated into economic terms through discounted cash flow modeling. Volume distributions are converted into production profiles using development concepts appropriate to deepwater salt-tectonic settings, with cost and schedule assumptions calibrated to regional analogs. Economic evaluations are performed under multiple price scenarios to assess robustness to market volatility.

For each prospect, probabilistic economic outcomes are generated, enabling calculation of Expected Monetary Value (EMV), Chance of Economic Success, and other risked value metrics. Rather than ranking prospects solely on absolute EMV, the framework emphasizes efficiency metrics such as EMV per unit area, EMV per well cost, and EMV per dollar of seismic investment. These measures facilitate meaningful comparison across prospects of different scales and cost structures.

At the portfolio level, individual prospect distributions are aggregated, accounting for CRS-defined risk correlations. This aggregation allows evaluation of portfolio behavior under different capital deployment strategies and highlights the impact of concentration versus diversification within salt-tectonic plays. The resulting rankings are transparent, auditable, and explicitly linked back to geological assumptions.

Phase 4: Capital Allocation Guidance and Decision Feedback

The final phase translates portfolio rankings into actionable capital allocation guidance. First, Value of Information (VOI) analysis is applied to assess whether additional data—most notably OBN seismic—can materially reduce key uncertainties identified in earlier phases. VOI is evaluated at the CRS and portfolio levels, enabling prioritization of seismic acquisition where uncertainty reduction yields the greatest uplift in risked value.

Second, the ranked portfolio informs block-level decisions for bid rounds, farm-ins, or relinquishments. Blocks are evaluated not only on standalone prospect value, but on their contribution to portfolio balance and optionality. Third, risk-versus-reward visualizations, such as portfolio matrices and cumulative value curves, are used to align partners and investment committees around shared expectations of uncertainty and value.

Critically, decisions taken in this phase feed back into the workflow. Acquisition of new seismic data, changes in portfolio composition, or partner-driven constraints trigger re-entry into Phase 1 or Phase 2, updating CRS definitions, uncertainty ranges, and rankings. In this way, the methodology functions as a closed-loop system, continuously integrating geoscientific learning with disciplined capital allocation in deepwater salt-tectonic exploration.

RESULTS

Results: Demonstration of Applied Impact in the U.S. Gulf of America

Case Study Context

The framework was applied to a deepwater sector of the U.S. Gulf of America characterized by complex allochthonous salt canopies, stacked minibasin stratigraphy, and a mixed exploration–appraisal maturity. The area encompassed approximately 3,500 km² of leased and open acreage in water depths ranging from 1,800 to 2,800 m. Available data included regional narrow- and wide-azimuth legacy seismic, several reprocessed depth-migrated volumes of variable vintage, and a sparse calibration set of legacy wells penetrating supra-salt and shallow subsalt objectives. No wells had directly tested the deeper subsalt play targeted by the current exploration campaign.

The strategic objective was twofold. First, the operator sought to rationalize an existing exploration portfolio ahead of an upcoming federal license round, identifying which blocks merited aggressive bidding, which should be retained opportunistically, and which should be relinquished. Second, the team needed to determine whether a focused ocean-bottom node (OBN) seismic program could be justified to reduce critical subsalt uncertainties, given competing demands for capital within a constrained corporate exploration budget. These decisions were to be made in a partner-operated setting, requiring transparent communication of both geological uncertainty and value implications.

Technical Outputs

Application of the integrated 2G&R synthesis resulted in a coherent, play-scale geological model that highlighted the dominant controls on prospectivity. Common Risk Segment mapping proved particularly influential in clarifying risk dependencies across the portfolio. For example, *Figure 3* (described) illustrates the CRS map for reservoir presence, delineating three principal subsalt depositional fairways associated with salt-withdrawal minibasins. High-confidence reservoir CRS zones were defined where seismic geomorphology suggested sand-prone turbidite systems with favorable confinement, while lower-confidence zones reflected areas of ambiguous seismic character or likely mud-prone deposition.

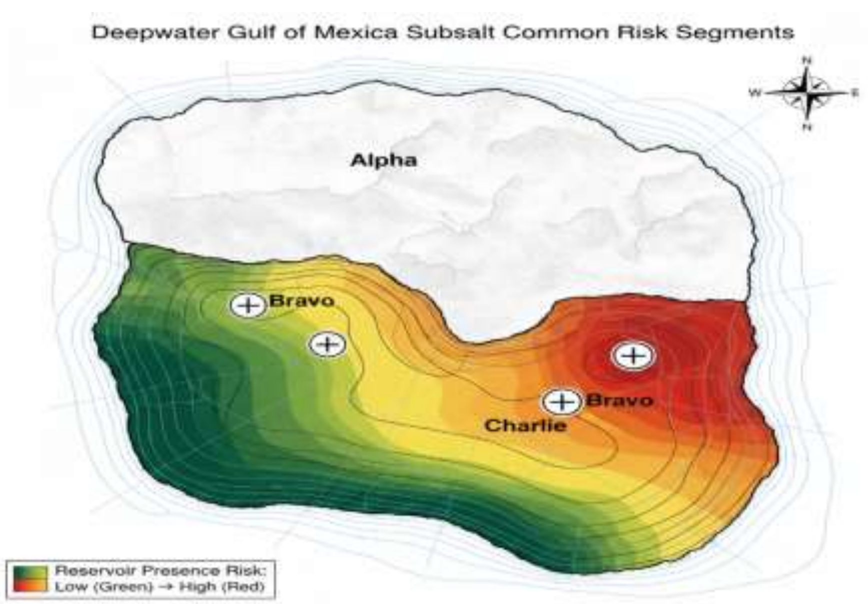

Figure: Common Risk Segment map illustrating spatial variation in reservoir presence risk across the subsalt play.

Complementary CRS maps were generated for charge access and trap integrity. *Figure 4* (described) shows the charge CRS, emphasizing areas of likely hydrocarbon access beneath salt canopies where weld continuity and fault connectivity were inferred from depth imaging and basin modeling. Importantly, these maps revealed that several prospects shared common charge risk, effectively coupling their chance of success and underscoring the need for portfolio-level, rather than prospect-isolated, evaluation.

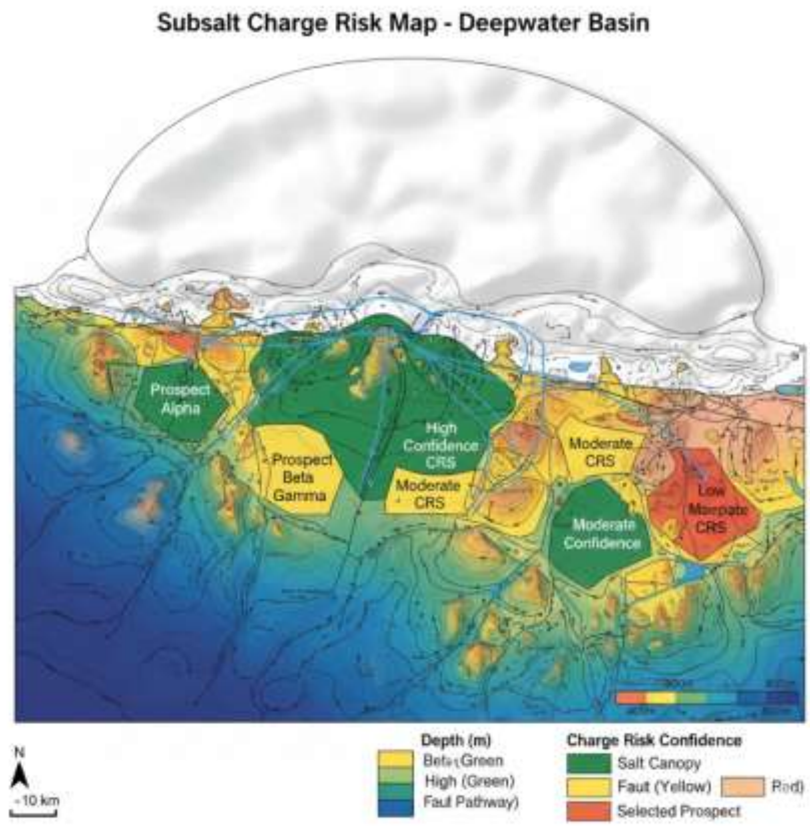

Figure: Charge access Common Risk Segment map highlighting subsalt migration risk beneath complex salt tectonics.

Probabilistic volumetric analysis was conducted for twelve prospects, of which the top five—Prospects Alpha, Bravo, Charlie, Delta, and Echo—dominated portfolio value. Monte Carlo simulation produced recoverable volume distributions that were materially skewed, reflecting the combined effects of reservoir presence uncertainty and trap size variability. Prospect Alpha, for example, exhibited a P90 of 45 MMboe, a P50 of 120 MMboe, and a P10 exceeding 350 MMboe, driven by significant upside in areal closure contingent on subsalt imaging uncertainty. In contrast, Prospect Delta showed a narrower distribution (P90/P50/P10 of 60/95/160 MMboe), reflecting more constrained geometry but higher reservoir confidence due to its position within a well-imaged minibasin.

British Journal of Earth Sciences Research, 14(1),73-95, 2026
Print ISSN: 2055-0111 (Print)
Online ISSN: 2055-012X (Online)
Website: https://www.eajournals.org/
Publication of the European Centre for Research Training and Development -UK

These distributions preserved information critical to downstream decision-making. Notably, prospects with similar P50 volumes displayed markedly different downside risk and upside leverage, distinctions that would have been obscured under deterministic or mean-value-only assessments.

Portfolio Ranking Outputs

The volumetric outputs were translated into probabilistic economic metrics under three commodity price scenarios. *Table 2* (described) summarizes the ranking of the top eight prospects by Expected Monetary Value (EMV), Chance of Economic Success, and EMV per well cost. The results demonstrated a clear divergence from rankings based solely on unrisked or even risked P50 volumes.

Prospect Alpha, while ranking second in terms of P50 volume, emerged as the highest EMV opportunity due to its exceptional upside and moderate well cost relative to potential reward. Prospect Bravo, which had the largest unrisked volume, ranked fourth in EMV because of compounded charge and reservoir CRS risks that materially reduced its chance of success. Conversely, Prospect Delta ranked third in volume but second in EMV efficiency (EMV per dollar of well cost), making it particularly attractive in a capital-constrained environment.

At the portfolio level, aggregation of prospect distributions highlighted concentration risk associated with overexposure to a single charge CRS. This insight prompted a rebalancing of the ranked opportunity set to include a mix of high-impact, charge-dependent prospects and lower-risk, infrastructure-adjacent opportunities. The resulting ranked portfolio differed materially from a "largest volume wins" approach, favoring capital efficiency and risk-adjusted value creation.

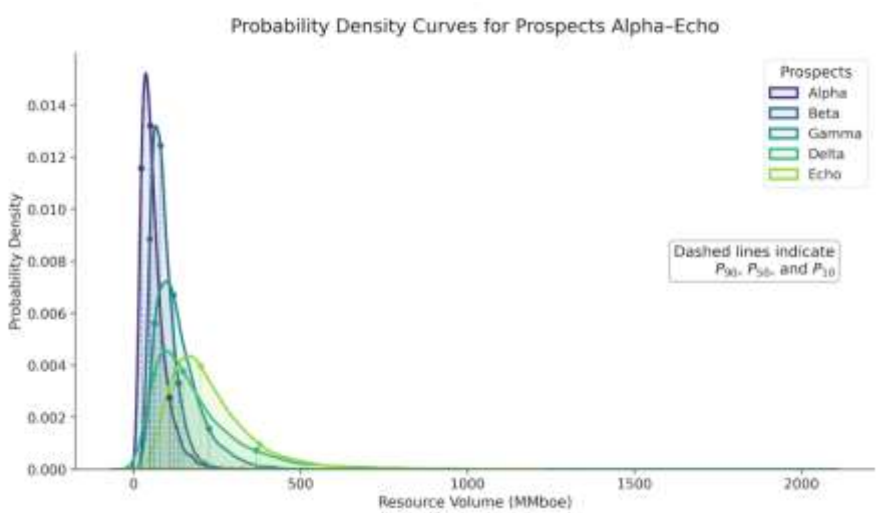

Figure: Probabilistic recoverable volume distributions for the five highest-ranked prospects.

Print ISSN: 2055-0111 (Print)
Online ISSN: 2055-012X (Online)
Website: https://www.eajournals.org/
Publication of the European Centre for Research Training and Development -UK

Capital Allocation Decisions Driven by the Framework

Decision 1: OBN Seismic Acquisition

The most consequential outcome of the framework was its direct influence on the decision to acquire OBN seismic. Value of Information analysis was conducted for the three highest-ranked prospects—Alpha, Bravo, and Charlie—which collectively accounted for over 60% of the portfolio's EMV but were all sensitive to subsalt imaging uncertainty.

For Prospect Alpha, the VOI analysis indicated a greater than 70% probability that improved imaging would shift the volumetric distribution sufficiently to generate an NPV uplift exceeding the cost of the survey. The expected value uplift was driven primarily by reduction in structural uncertainty at the crest of the closure and improved discrimination between competing reservoir geometries. On this basis, the framework supported approval of a targeted OBN program, budgeted at approximately $80 million, focused on a 1,200 km² area encompassing the Alpha–Charlie CRS cluster. Importantly, the decision was framed not as a technical enhancement, but as a capital allocation choice with a quantified risk–reward justification.

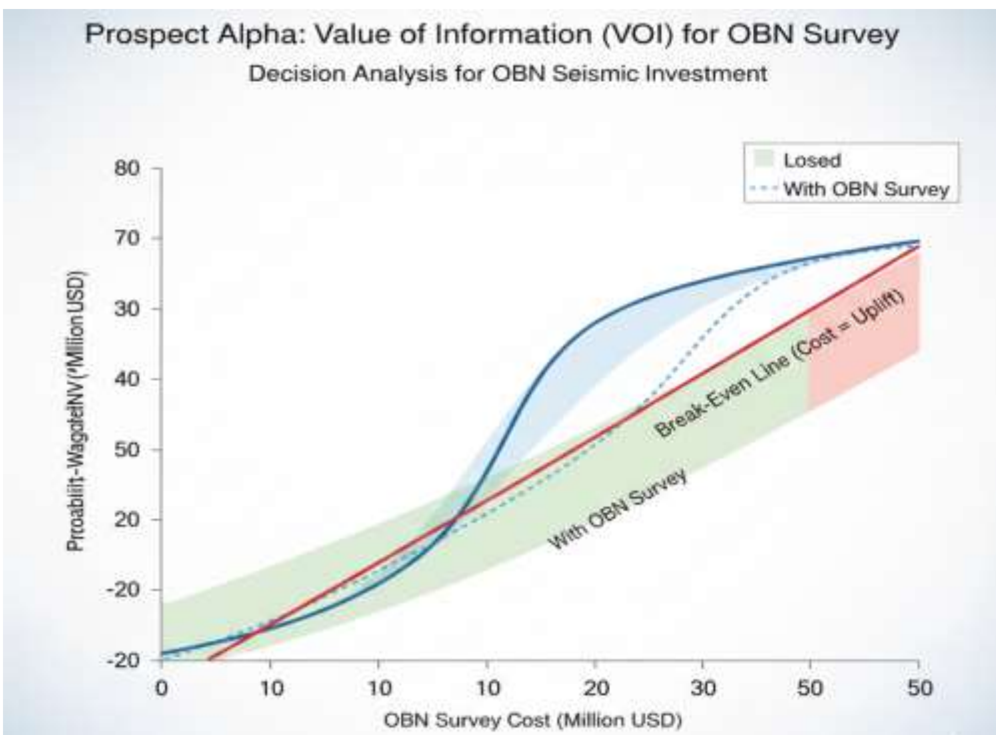

Figure: *Value of Information analysis demonstrating the economic justification for targeted OBN seismic acquisition.*

British Journal of Earth Sciences Research, 14(1),73-95, 2026
Print ISSN: 2055-0111 (Print)
Online ISSN: 2055-012X (Online)
Website: https://www.eajournals.org/
Publication of the European Centre for Research Training and Development -UK

Decision 2: Block Ranking and Acreage Management

The ranked portfolio was then translated into block-level recommendations for the upcoming license round. Blocks were evaluated based on the aggregated EMV of contained prospects, CRS diversity, and optionality for future appraisal or tie-back development.

Block 9 emerged as the highest-ranked block, driven by its containment of two top-quartile prospects within a favorable reservoir and charge CRS, as well as its proximity to existing infrastructure. The framework recommended aggressive bidding for this block, positioning it as a cornerstone of the future portfolio. In contrast, Block 4, despite hosting a single large unrisked prospect, ranked low due to its isolation within a high-risk charge CRS and lack of cluster potential. The recommendation was to relinquish Block 4 at lease expiry, freeing capital and organizational focus for higher-quality opportunities.

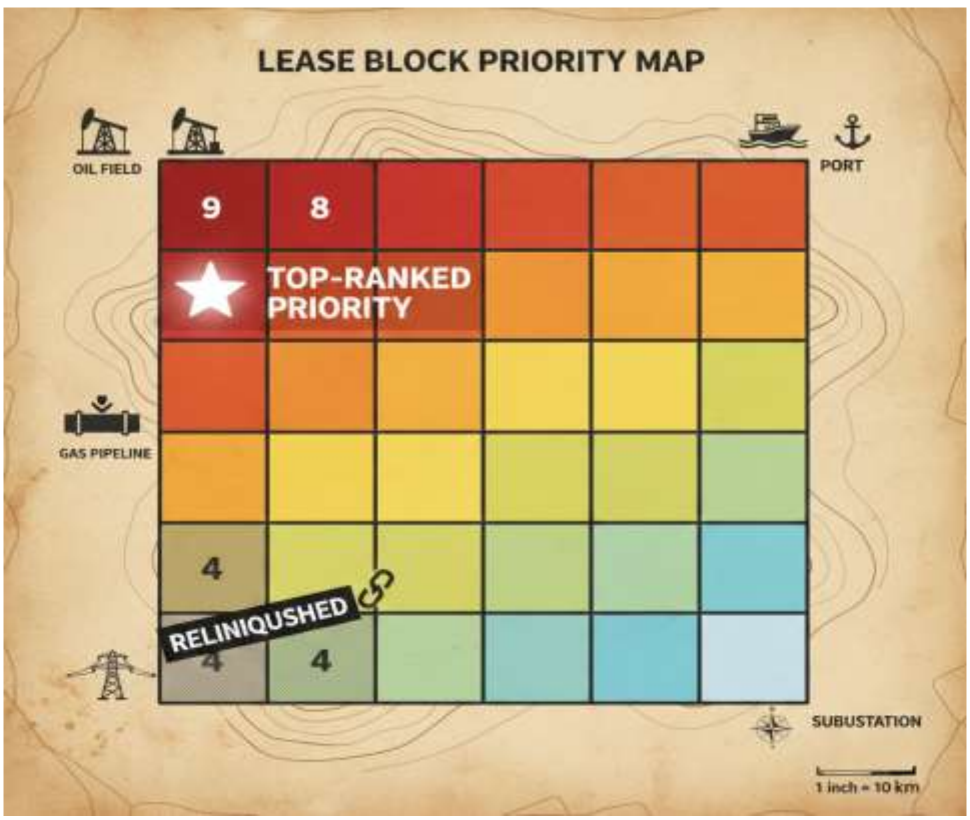

Figure: *Block-level ranking derived from portfolio aggregation, guiding bid-round and relinquishment decisions.*

These recommendations were adopted largely unchanged, demonstrating the credibility of the framework in guiding tangible acreage decisions.

Decision 3: Partner Alignment and Investment Communication

Finally, the results were synthesized into risk-versus-reward visualizations used to align partners and senior management. *Figure 5* (described) presents a portfolio matrix plotting EMV against Chance of Economic Success, clearly differentiating high-risk/high-reward frontier prospects from lower-risk, infrastructure-led opportunities.

This visualization proved instrumental in facilitating partner alignment. Rather than debating individual geological interpretations, discussions focused on portfolio balance, capital exposure, and strategic intent. Agreement was reached on a phased strategy that combined participation in the OBN-enabled high-impact prospects with selective advancement of lower-risk opportunities, aligning risk appetite across the partnership.

Prospect Ranking Table

Prospect Name	EMV ($M)	Chance of Success (%)	EMV per Well Cost	P50 Volume (MMbbl)	Volume Rank
Prospect B	22.0	40	2.2	85	4
Prospect A	18.5	25	1.23	120	3
Prospect D	15.8	60	1.98	45	6
Prospect E	14.2	20	0.71	150	2
Prospect C	12.4	15	0.5	200	1
Prospect F	10.5	35	0.88	60	5

Figure: Comparison of prospect rankings based on risked economic metrics versus volume-driven screening.

Collectively, these results demonstrate that the proposed framework did more than refine technical understanding; it directly shaped multi-million-dollar investment decisions. By preserving geological fidelity while translating uncertainty into decision-relevant metrics, the approach enabled disciplined capital allocation in a complex deepwater salt-tectonic setting, fulfilling its objective as a practical bridge between prospect ranking and portfolio strategy.

Figure: Cross-plot demonstrating divergence between volumetric scale and risk-adjusted economic value.

DISCUSSION

From Technical Evaluation to Strategic Transformation

Interpretation of Key Findings

The central finding of this study is not merely that an integrated geoscience-to-investment framework can be constructed, but that its disciplined application materially altered investment outcomes relative to traditional, heuristic approaches. In the Gulf of America case study, prospect ranking and capital deployment decisions differed demonstrably from those derived using volume-led or intuition-driven screening. Opportunities that appeared compelling on the basis of unrisked or even risked P50 volumes were deprioritized when evaluated through a portfolio lens that explicitly accounted for shared geological risks, uncertainty distributions, and capital efficiency. Conversely, prospects with less headline scale but superior risk-adjusted value and efficiency metrics were elevated within the portfolio.

This shift is significant because it moves exploration decision-making away from narrative dominance and toward quantifiable, auditable logic. The framework did not eliminate uncertainty—nor should it—but it rendered uncertainty visible, comparable, and actionable. The decision to sanction a multi-million-dollar OBN seismic program, for example, was not justified on the generalized premise of “improving subsalt imaging," but on a quantified probability that information gained would translate into economic value exceeding its cost. In this sense, the most important result is that technical subsurface analysis became a decisive input to capital allocation, rather than a post hoc justification for decisions made on other grounds.

Broader Implications for Exploration Practice

The implications of this approach extend well beyond the specifics of the case study. At an organizational level, the framework institutionalizes capital discipline by embedding economic consequences directly within geoscientific workflows. Geoscience teams are no longer asked merely to mature prospects, but to articulate how uncertainty, when propagated through volumetric and economic models, competes for scarce capital at the portfolio level. This reframing aligns technical excellence with corporate imperatives, particularly in an era where exploration capital must compete internally with short-cycle and lower-risk investment options.

For joint ventures and partner-operated settings, the framework offers a step-change in transparency. By grounding prospect ranking and capital decisions in traceable CRS definitions, probabilistic outcomes, and clearly defined efficiency metrics, it provides a common language for discussing risk and reward. This is particularly valuable in deepwater settings, where partners often bring differing risk appetites, strategic objectives, and internal economic assumptions. The use of portfolio matrices and VOI-based justifications shifts discussions away from binary debates over geological interpretations and toward strategic alignment around balanced portfolios and staged investment.

Perhaps most importantly, the framework repositions subsurface technical work as a strategic planning tool. Geological interpretation, uncertainty analysis, and economic evaluation are no longer sequential steps culminating in a static ranking, but components of a dynamic system that informs acreage strategy, data acquisition, and partner engagement. In this model, geoscience does not merely feed decisions; it actively shapes the range of strategic options considered viable. This represents a fundamental change in how exploration organizations can leverage their technical capability to influence long-term value creation.

Limitations and Residual Uncertainties

Notwithstanding its demonstrated impact, the framework is subject to limitations that warrant careful consideration. Foremost among these is its dependence on the quality and relevance of input data. CRS mapping, probabilistic parameter definition, and economic modeling are only as robust as the seismic, well calibration, and analog datasets on which they are based. In frontier or data-poor settings, uncertainty ranges may necessarily be broad, and the resulting economic distributions correspondingly diffuse.

A related limitation lies in the unavoidable subjectivity inherent in initial risk assignments. While CRS mapping enforces internal consistency, the definition of risk probabilities and parameter distributions still relies on expert judgment. This subjectivity cannot be fully eliminated and, if unacknowledged, may create a false sense of precision. The framework addresses this risk not by claiming objectivity, but by making assumptions explicit and by testing their influence on outcomes through sensitivity and scenario analysis.

The iterative, closed-loop nature of the workflow is a critical mitigation of these limitations. As new data become available—most notably from OBN seismic acquisition—CRS definitions, uncertainty ranges, and volumetric distributions are updated, and the portfolio is re-ranked accordingly. In this sense, the framework is not a one-time evaluation but a living system that evolves with the subsurface understanding. Importantly, this adaptability reinforces, rather than undermines, decision confidence by demonstrating how value assessments change in response to new information.

Recommendations for Future Work and Broader Application

While developed and demonstrated in a deepwater salt-tectonic context, the principles underlying the framework are broadly transferable. Other structurally complex settings, such as fold-and-thrust belts, basement-involved rift systems, or basalt-covered provinces, exhibit similar challenges of imaging uncertainty, risk dependency, and high capital exposure. Adapting CRS definitions and uncertainty parameterization to these environments represents a natural extension of the approach.

There is also significant potential to integrate emerging analytical techniques. Machine learning methods, for example, could be employed to inform the definition of uncertainty ranges by leveraging large seismic attribute datasets or global analog libraries. Such integration would not replace expert judgment, but could provide data-driven constraints that enhance consistency and reduce bias in parameter selection.

Beyond conventional hydrocarbon exploration, the framework has relevance for other subsurface energy applications. Geothermal development, carbon capture and storage (CCS), and subsurface hydrogen storage all involve significant geological uncertainty, high upfront data acquisition costs, and long-term capital commitments. Applying a similar geoscience-to-investment workflow could improve site selection, derisk appraisal strategies, and align technical evaluation with investment decision-making in these emerging sectors.

In aggregate, the broader significance of this work lies in its demonstration that integration—not novelty—is the key to improving exploration outcomes. By connecting mature but traditionally siloed disciplines into a coherent, decision-focused framework, this study offers a practical pathway for transforming how subsurface uncertainty informs capital allocation in complex geological settings.

CONCLUSION

Deepwater salt-tectonic exploration sits at the intersection of exceptional opportunity and exceptional risk. While the industry has developed highly sophisticated tools for subsurface interpretation and uncertainty analysis, a persistent decision gap remains between geoscientific insight and the binary, capital-intensive choices that ultimately shape exploration portfolios. The purpose of this paper was to address that gap by presenting an integrated, geoscience-to-investment framework capable of translating complex subsurface uncertainty into transparent, decision-relevant capital allocation guidance.

At its core, the framework is built on a closed-loop integration of three elements: rigorous 2G&R synthesis anchored in Common Risk Segment mapping, probabilistic volumetric and uncertainty analysis that preserves geological causality, and portfolio-level economic ranking that explicitly incorporates risk, value, and capital efficiency. These components are linked sequentially yet iteratively, allowing technical insights to directly inform economic outcomes and, in turn, guide strategic decisions on data acquisition, acreage management, and partner alignment.

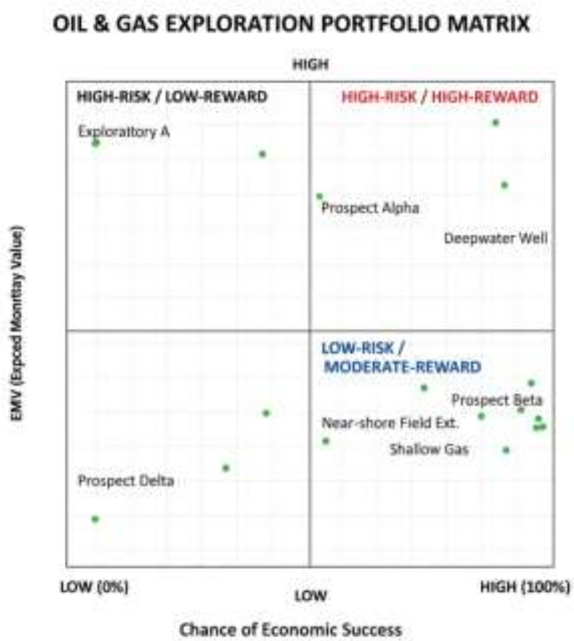

Figure: Portfolio risk–reward matrix used to align partners on balanced exploration and capital deployment strategy.

The application of this framework to a deepwater Gulf of America case study demonstrated its practical impact. Rather than reinforcing traditional volume-led or heuristic rankings, the approach produced a materially different prioritization of prospects and blocks, grounded in auditable assumptions and probabilistic outcomes. Most notably, it provided a defensible, quantitative basis for sanctioning a multi-million-dollar OBN seismic program by demonstrating a high probability that information gained would translate into economic value exceeding its cost. Similarly, the framework guided block-level decisions in a license round, supporting the prioritization of high-quality, cluster-driven acreage and the relinquishment of lower-value positions. In each instance, a clear line of sight was maintained from seismic interpretation and geological risk assessment through to specific capital allocation decisions.

Beyond the individual decisions it informed, the framework illustrates a broader shift in how deepwater exploration can be practiced. By preserving geological fidelity while embedding economic relevance, it transforms subsurface evaluation from a predominantly technical exercise into a strategic planning capability. It enables organizations and partners to engage in informed, transparent discussions about risk and reward, and to deploy capital where it has the highest probability of generating sustainable value.

As exploration increasingly targets the world's remaining complex hydrocarbon resources—often beneath salt, in deepwater, or in structurally challenging settings—the tolerance for opaque, intuition-driven capital allocation continues to diminish. Integrated, quantitative approaches of the type presented here are no longer optional enhancements; they are essential tools for sustaining capital discipline, aligning stakeholders, and ensuring that geoscientific excellence translates into enduring exploration success.

REFERENCES

Barbosa, C. H. S., Kunstmann, L. N. O., Silva, R. M., Alves, C. D. S., Silva, B. S., Filho, D. M. S., Mattoso, M., Rochinha, F. A., & Coutinho, A. L. G. A. (2020). A workflow for seismic imaging with quantified uncertainty. *arXiv*.

Pradhan, A., Le, H. Q., Dutta, N. C., Biondi, B., & Mukerji, T. (2019). Approximate Bayesian inference of seismic velocity and pore pressure uncertainty with basin modeling, rock physics and imaging constraints. *arXiv*.

Leveille, J. P., Jones, I. F., Zhou, Z., Wang, B., & Liu, F. (2011). Subsalt imaging for exploration, production, and development: A review. *Geophysics*, 76(5), WB3–WB20.

Sheng, J., Yoo, S., Reta-Tang, C., & Rodriguez, G. (2018). Enhancing salt and subsalt imaging in deep water, Gulf of Mexico, with common offset RTM gathers. *CSEG RECORDER*, 43(02).

Abdullah, S. A., Barker, S. M., Jong, J., Watanabe, Y., & Bakar, D. A. N. A. (2018). A play-based evaluation of a deepwater Sabah exploration area: Prospect maturation and implications for remaining prospectivity. *Proceedings of the SPWLA 59th Annual Logging Symposium*.

Mohammadi, M. (2025). Probability forecast verification in petroleum exploration. *Petroleum Geoscience*.

LaCosta, W. C. P. (2022). Petroleum exploration portfolios generated with different optimization approaches: Lessons for decision-makers. *Journal of Petroleum Exploration and Production Technology*.

Bratvold, R. B., & Bickel, J. E. (2009). Value of information in the oil and gas industry: Past, present, and future. *SPE Reservoir Evaluation & Engineering*.

McMaster, G. (n.d.). Merging risk assessment and portfolio management: EMV and decision analysis in exploration. *Society of Petroleum Engineers Technical Paper*.

Surovtsev, D. (2019). Advanced analytics approach to exploration portfolio design. *Search and Discovery*.

Stigliano, M., et al. (2005). Combining decision analysis and portfolio management to improve project selection in the E&P firm. *International Journal of Project Management*.

Suslick, S. B., Schiozer, D. J., & Rodriguez, M. R. (2009). Uncertainty and risk analysis in petroleum exploration. *TERRAe–Unicamp*.

Newendorp, P. D., & Schuyler, J. R. (2000). *Decision analysis applied to exploration risk and portfolio optimization*. AIME.

Edwards, D., & Hewett, T. A. (1993). Risk and portfolio analysis in petroleum exploration. *AAPG Bulletin*, 77(9), 1639–1652. [Foundational work often cited in portfolio optimization literature]

Markowitz, H. (1952). Portfolio selection. *The Journal of Finance*, 7(1), 77–91. [Foundational portfolio theory]

Pickering, S., & Bickel, J. E. (n.d.). The value of seismic information. *Oil & Gas Journal*.

Jones, C. M. (2018). The oil and gas industry must break the paradigm of the current exploration model. *Journal of Petroleum Exploration and Production Technology*, 8(131–142).

Gray, L. J., et al. (2001). Challenges in seismic imaging of complex reservoirs and the need for uncertainty quantification. *Energy Reports*.

Klett, T. R. (2005). Uncertainty analysis applied to petroleum resource assessment. *U.S. Geological Survey Digital Data Series*. [Seminal USGS methodology on resource uncertainty]

Society of Petroleum Engineers. (2024). *SPE Petroleum Resources Management System (PRMS)*. SPE. [Standard for reserves and uncertainty reporting]