Use of global analogues to improve decision quality in exploration, development, and production

Shaoqing Sun, David A. Pollitt, Shengyu Wu, and David A. Leary

ABSTRACT

Global analogues are widely used across the exploration and production (E&P) life cycle. Analogues, used in conjunction with primary data, expand the knowledge of both the individual and team and develop insights that are not possible from using either local data or individual experience in isolation. Difficulties in the application of analogues arise when the analogues are not selected consistently, are too specific, or are in conflict with empirical local data. Most of these difficulties arise from the lack of a proper definition of analogues, absence of a systematic method of analogue selection, and poorly defined objectives for the use of analogues. Analogues are herein defined as comparable fields and reservoirs relevant to a specific question or set of questions. To select appropriate analogues, practitioners should focus on specific individual question(s) instead of "look-alike" fields.

A consistent global field and reservoir knowledge base with standardized and classified geological and engineering parameters form the basis for analogue selection and analysis. The ability to standardize knowledge on practitioners' own E&P assets and conduct benchmark comparisons against applicable global analogues is critical to the identification of potential problems, mitigation strategies, and best practices. Appropriate application of global analogues to a local situation not only fosters creative thinking but also provides a way to quickly learn, increase confidence, and efficiently reduce risk for E&P decision-making.

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INTRODUCTION

In the upstream industry, there is widespread agreement about the need and usefulness of analogue data (Sun and Wan, 2002; Howell et al., 2014), but beyond the process of selecting analogue data for proved reserves reporting (Hodgin and Harrell, 2006; Sidle and Lee, 2010), there are few well-published processes or workflows to locate and extract meaningful analogue data, either from public literature or proprietary company files. Part of the challenge facing the widespread use of analogues is that (1) data are rarely harmonized or consistently structured and (2) there is a lack of consistent methods used to filter the analogue data prior to analysis.

The filtering of sufficiently structured and harmonized data prior to analysis constitutes the first of two necessary steps in the process of using analogues. This allows the user to broadly define the scope of the analogue search using well-agreed parameters (e.g., lithology, hydrocarbon type, drive mechanism, etc.). The risk inherent to this approach is that the user may adopt overspecific filters that inadvertently restrict valid scenarios for consideration (Volpi et al., 2003). To address this issue, several attempts have been made to broaden the analogue search using a case-based reasoning approach (Bhushan and Hopkinson, 2002; Temizel and Dursun, 2013), multivariate statistical techniques (Volpi et al., 2003; Rodriguez et al., 2013), and machine learning algorithms (Brazil et al., 2018). However, relying upon algorithms to conduct screening based upon chosen key parameters and weighting factors may inadvertently include analogues that are not necessarily valid. Irrespective of the approach chosen, this study argues that the analogue selection process is best accomplished using a team-based approach, with geoscientists and engineers working toward a common goal based upon specifically chosen, standardized geological and engineering parameters.

The purpose of this paper is to present a systematic, objective, and integrated methodology for an analogue selection and solution workflow. Empirical exploration, development, and production examples are discussed within the framework of the analogue solution workflow. These examples demonstrate how risk and uncertainty can be reduced with the appropriate use of global analogue intelligence, ultimately improving decision quality and realizing value from the adoption of the workflow.

VALUE OF APPROPRIATE ANALOGUES AND COMMON PITFALLS

When properly chosen analogues are used in conjunction with primary data, they can quickly broaden and deepen the knowledge of both the individual and team through the development of new insights that might otherwise not be available from either local data alone or any individual's prior experiences. In addition to augmenting an individual's background and perspective, properly chosen analogues help to calibrate risk and uncertainty and can increase decision quality through all phases of the exploration and production (E&P) life cycle (Figure 1).

Analogue data are most commonly used in the case of resource estimation, particularly in the exploration and early development stages when information from direct measurement is limited (Society of Petroleum Engineers, 2018). Analogues are also commonly applied to aid assessment of economic producibility, production decline characteristics, drainage area, and recovery factor (for primary, secondary, and tertiary methods). When properly selected, analogues provide a basis for probabilistic distribution of key parameters and solutions to critical issues facing prospect evaluation, field development planning, production enhancement, and reserves booking (Figure 1).

When applying learnings derived from the use of analogues, it is important to consider that only information from appropriate analogues is useful, and poorly selected analogues can act to limit the understanding of a prospect or asset as much as a proper application can help. When analogues to the target prospect, discovery, or field are poorly understood (and therefore selected inappropriately), too narrow in scope, or dogmatically applied, they run the risk of being overly prescriptive, ignoring local variations in rock and fluid properties. Therefore, it is important to know how and when to select the right analogues and for what purpose. These sorts of challenges arise when selection is made without a structured, standardized, and classified knowledge framework or when they are chosen too specifically or arbitrarily.

When analogues conflict with local data, there is a natural tendency for users to compromise the analogue selection in a way that confirms their a priori assumption. Analogue information is commonly incorporated on an ad hoc basis, relying on a project team's recommendation and knowledge from their own experience. Selecting the wrong population of analogues from which best practices and key learnings can be drawn is a common mistake. Like-for-like comparison is therefore essential, and it is demonstrated in this study that this is only achievable through rigorous standardization, consistent rules, and a comprehensive classification scheme.

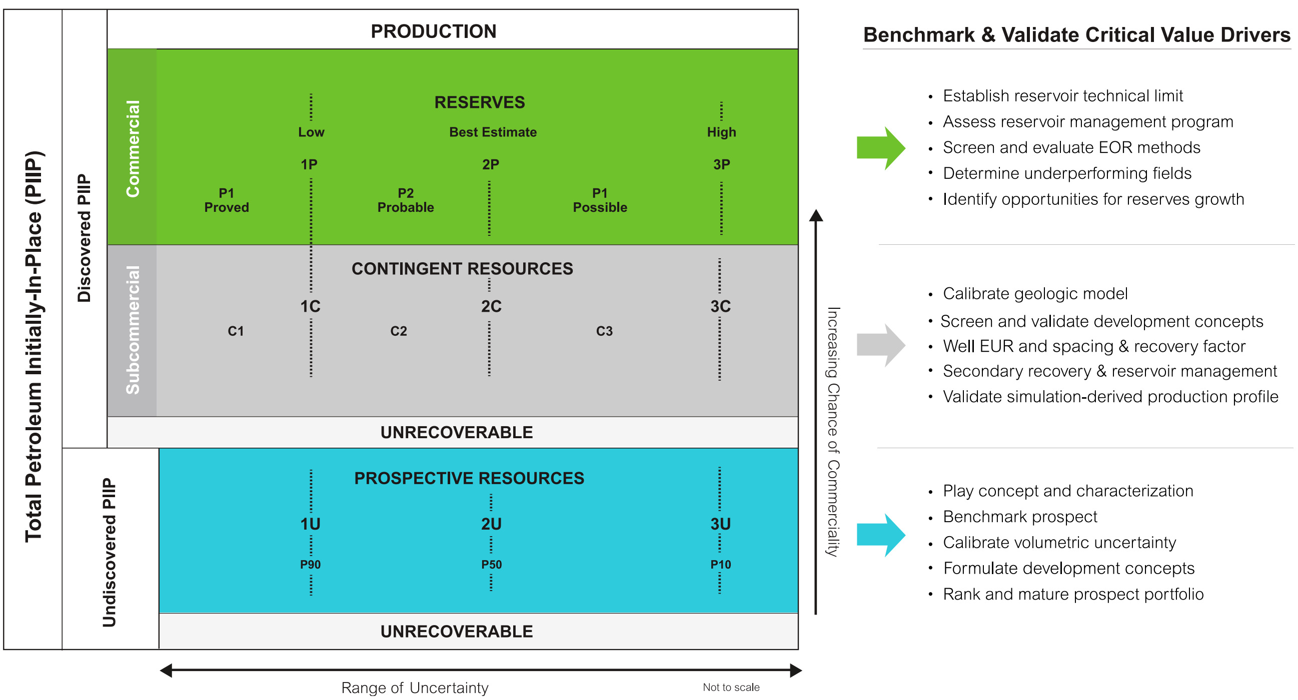


Figure 1. Value of global analogues in the context of petroleum resource management framework. C = contingent resources; EOR = enhanced oil recovery; EUR = estimated ultimate recovery; P = reserves; U = prospective resources.

ANALOGUE METHODOLOGY

Historically, prior to the widespread use of personal computing, the use of analogues relied upon personal experience, both individual and team-based, and analogues were commonly selected based on geographic proximity, using data available from the same play or basin. A systematic way of comparing global analogues did not exist and, where it was at all possible, the process was slow and comparisons were commonly qualitative in nature. In competitive situations (e.g., bid rounds, tenders, farm-ins, and sales), abundant, high-quality, and relevant literature on applicable analogues was challenging to find and apply within a limited time.

Today's environment, with abundant global data available, presents a new challenge: the management, storage, and analysis of a rapidly growing, large, and diverse database. In broad terms, it can be said that the oil and gas industry has moved from a position of not having enough subsurface information to an over-abundance of both data and information (Perrons and Jensen, 2015). Organizations are now more likely to be constrained by time, capability, or capital than by data. This situation tends to lead to less knowledge and decreased insight.

The data used in this study are a proprietary compilation of more than 1600 global reservoirs, compiled using more than 50,000 public domain publications. Crucially, the information used to compile this analogue knowledge base has been consistently standardized and parameterized into approximately 420 variables for each reservoir. This allows consistent and appropriate comparisons to be made on an equal basis between analogues.

Analogue Standardization

When building an analogue knowledge base from diverse public domain data sources or from internal company data, the data set rarely appears complete, and individual parameter values rarely make sense without sufficient context. Furthermore, parameter values from different sources may conflict with each other for numerous reasons (e.g., differing languages, practices, geologic terms, and engineering units). Rather than attempting numerical or statistical means to address these inconsistencies, the workflow presented here advocates structuring and standardizing the analogue knowledge itself. This process involves collecting, reviewing, and synthesizing geological, reservoir engineering, and production data on a representative sample of global reservoirs and fields. These field case studies account for more than 70% of global conventional recoverable reserves and, collectively, document both best practices and technical failures from global exploration and production over the past century. To be able to compare fields and reservoirs globally, it is first necessary to standardize terminology and units and then apply the same classification scheme to the reservoirs and fields described in the literature. Each field case study details how and why the prospect was drilled and then covers the basin genesis and source rock, followed by a detailed description of the structure and trap definition, reservoir characteristics, and fluid properties. It also covers resources and methods of hydrocarbon recovery, including development strategy, reservoir management practices, and improved recovery techniques applied and their outcomes.

A comprehensive data model with 420 geological and reservoir engineering parameters is created at both the reservoir and field level (Table 1). Each attribute is consistently defined and contains a set of standardized values following a holistic classification scheme. As examples, the hierarchy of classification for lacustrine depositional systems and environments (Figure 2) and erosional truncation traps (Figure 3) are provided. The intent of this data model is that it generates a coherent and consistent knowledge base of geological, engineering, and production parameters (Table 2). Although no classification scheme is perfect and universally agreed upon, it is critical that the terminology and parameters are consistent, well defined, and genetically based and have definitions readily accessible to the practitioners. By employing these consistent standards, practitioners can capture their own reservoir and field knowledge for comparison with a broader knowledge base.

Analogue Selection

Finding the most relevant analogues to a given prospect or field is essential to transform knowledge into critical insight and intelligence for E&P decision-making. It

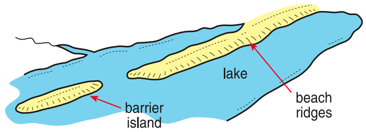
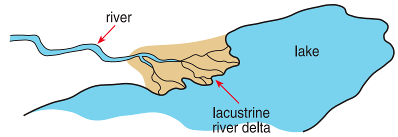
Table 1. Field and Reservoir Knowledge Structure with Emphasis on Parameters for Reservoir Characteristics (This Is an Example of a Greater Number of Standardized Variables)

RESERVOIR-LEVEL PARAMETER	Reservoir characteristics
• General	• Reservoir age
• Well	• Tectonic setting
• Source	• Depositional environment
• Trap	• Sandbody type
• Seal	• Fluid flow restriction
• **Reservoir characteristics**	• Gross reservoir thickness
• Fluid	• Net reservoir thickness
• Resource	• Net-to-gross ratio
• Production	• Net pay thickness
• Improved recovery	• Reservoir lithology
	• Wettability
	• Sensitivity
	• Diagenetic reservoir type
	• Porosity type
	• Matrix, bulk and fracture porosity
FIELD-LEVEL PARAMETER	• Air and well test permeability
	• Permeability contrast
RESERVOIR & FIELD PRODUCTION DATA	• Vertical to horizontal permeability ratio

is a common mistake to only consider local analogues or analogue knowledge gained merely from the team's own experiences. It takes time and skill to research each global analogue, synthesize the information, and make results available for analysis. Some "analogue work" may be as simple as creating awareness and learning about the nature of accumulations within a basin or play. When used by geoscientists new to a basin, analogues can provide an accelerated path to a global perspective: the geoscientist might ask, "What kind of traps have worked in foreland basins around the world?" Knowing what one is looking for or having an awareness of what has worked in similar settings in other areas may increase the likelihood of finding a fresh insight in a different region. Although the effective use of local data is important, there may be specific plays that are outside the knowledge of local experts. The ability to apply a globally based, structured, and classified knowledge framework to a local situation can help add an additional dimension of creativity and confidence to exploration. Examples are given herein as guidelines for analogue selection workflows to address typical challenges common to exploration, development, and production phases of the E&P life cycle.

The effectiveness of analogue application depends on an appropriate definition of an analogue, a systematic method of analogue selection, and a well-defined objective for the use of analogues. Analogues are herein defined as comparable fields and reservoirs relevant to a specific question or set of questions (e.g., analogues to understand porosity distribution and permeability anisotropy for karstic carbonates).

To select appropriate analogues, practitioners should focus on specific individual question(s) instead of "look-alike" fields. Selection of the relevant and applicable analogues depends on which part of the E&P life cycle a practitioner is concerned with, what drives project value, what challenging issues need to be solved, what critical decisions have to be made, and which information is missing. A detailed understanding of analogues is required within a structured and classified knowledge framework to ensure that valuable and real insights are captured. Methods of analogue selection and their application differ fundamentally depending on the discipline of the practitioners and the problem being addressed (Table 3). Every time the practitioners select an analogue search filter, they must question how critical and relevant the parameter in question is for the issues to be resolved, rather than make a superficial comparison to the field of interest. Problems of differing nature and for different objectives require different sets of analogues. Geoscientists may use analogues to validate play concepts, calibrate prospect uncertainty, or characterize permissible alternatives of a geologic model. When searching for analogues for this purpose, they may focus mainly on geologic parameters, such as tectonic

<table>
<tr><th>DEPOSITIONAL SYSTEM</th><th colspan="2">DEPOSITIONAL ENVIRONMENT</th><th>DEFINITION</th><th>CONCEPTUAL MODEL</th></tr>
<tr><td rowspan="4">Lacustrine
Deposits of nonmarine standing bodies of water.</td><td colspan="2">Lacustrine beach or barrier bar</td><td>Lake-margin facies formed by reworking by wave action or longshore currents. Typically elongate reservoirs, paralleling the lake shore.</td><td>
</td></tr>
<tr><td rowspan="2">Lacustrine delta
Sediment prisms deposited at mouths of rivers and alluvial fans.</td><td>Lacustrine river delta</td><td>Deposited at river mouths within low-relief distributary systems. Dominated by fluvial processes and interaction with lacustrine wave or longshore currents.</td><td>
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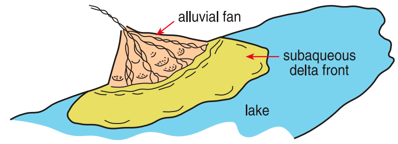
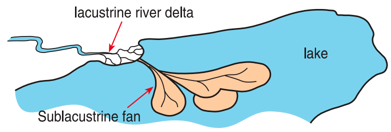
<tr><td>Lacustrine fan delta</td><td>Coastal prisms delivered to lake margin by alluvial fans and deposited mainly in shallow water. Developed in high relief basins, typically in semiarid areas.</td><td>
</td></tr>
<tr><td colspan="2">Sublacustrine fan</td><td>Turbidites typically deposited downslope of lacustrine river deltas and pass laterally into deep-lacustrine shales.</td><td>
</td></tr>
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Figure 2. Hierarchy of knowledge classification with an example for lacustrine depositional system and environment.

setting, lithology or depositional environment, geologic age, trapping mechanism, sand-body type, diagenetic reservoir type, and net-to-gross ratio (Table 3).

In contrast, reservoir engineers might use analogues to validate development concepts, better understand producibility, or estimate recovery factor. Key parameters for analogue selection in this case might include hydrocarbon type, development situation (onshore versus offshore), lithology or depositional environment, drive mechanism, rock and fluid properties, and field size (Table 3). Production engineers do not look for analogues per se; instead, they are more interested in knowledge and best practices from analogous reservoirs that share a common hydrocarbon type with similar rock and fluid properties, reservoir conditions, and production challenges. Following our analogue selection workflow, practitioners can find a range of analogues with different outcomes. These range from low-side outcomes with poor practice to high-side outcomes with best practice. Reservoir performance and recovery factor benchmarking is a fundamental step to identify the underperforming fields and apply best practices of the top-tier performers to optimize production performance and recovery efficiency (Table 3).

Analogue search and analysis is a process of research and discovery, integrating practitioners' expertise and knowledge on their target assets with global analogue intelligence. It is critical to strike an appropriate balance between the number and relevance of analogues. The selection of analogues should make both genetic and statistical sense; probabilistic results should be conducted based upon the suite of genetically related global analogues rather than just local data. It is the authors' experience that the most common pitfall in this process is too narrow parameter definition and overly aggressive filtering for analogues that resemble their fields in every aspect (tight categorization). Invariably, comparisons are difficult to make since there are never one-to-one matches in fields or reservoirs. To avoid this pitfall, users should look for analogues that can address a specific issue, within a structured and classified knowledge framework, instead of seeking a unique analogue to their target field. One set of appropriate analogues should only be used to calibrate one particular subsurface uncertainty.

Practitioners should start with a broad set of parameters to find a wide range of analogues (loose categorization), then narrow the field as appropriate to focus on the specific issue. No presumption or a

REGIME	CLASS	FAMILY	DEFINITION	SCHEMATIC CROSS SECTION
Erosional Trapping resulting from erosional truncation of reservoir.	Subunconformity truncation Reservoir truncation beneath a regional unconformity.	Regional subcrop	Reservoir truncation beneath regional-scale unconformity.	
		Paleostructural subcrop	Erosional truncation of faulted or folded structure.	
	Buried erosional relief Trapping beneath a local truncation surface and/or within a buried hill reservoir.	Buried hill	Erosional truncation of basement reservoir.	
		Truncation edge	Reservoir truncation beneath local or subregional unconformity or sequence boundary.	
	Onlap onto erosional surface Onlap pinch-out of reservoir onto relative high.	Onlap onto regional unconformity	Onlap pinch-out onto a regional unconformity.	
		Onlap onto structural flank unconformity	Onlap pinch-out onto flanks of structural or basement high.	
	Erosional trough fill Lateral termination of reservoir against an erosional trough.	Channel fill	Reservoir confined within a channel incision.	
		Valley fill	Reservoir confined within a major channel incision.	
		Canyon fill	Reservoir confined within deep-water submarine erosional trough.	

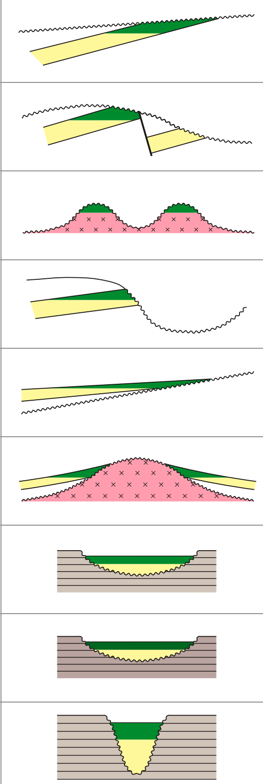

Figure 3. Hierarchy of knowledge classification with an example for erosional truncation traps.

priori knowledge is required for what is important; the only requirement is that the practitioners are open-minded and specific about their interest. Following the workflow will then indicate what is important. The general idea in the application of analogues should be to expand users' knowledge base to the point where they can make globally informed decisions about their own local data.

Analogue Solution Workflow

Analogues are widely used to calibrate subsurface uncertainty and production performance throughout the E&P life cycle (Sun and Wan, 2002) and have been demonstrated as critical to accurate resource assessment and reserves booking (Society of Petroleum Engineers, 2018). To assist geoscientists, reservoir engineers, and portfolio managers in efficiently expanding their knowledge, as well as gaining new insights on their own prospects and assets, we propose a five-step analogue solution workflow:

1. Define problems and objectives. Be clear about the specific problems to address and the critical questions to be answered.
2. Consistently document knowledge. Catalog your prospects, undeveloped discoveries, and producing assets using rigorous standards, consistent rules, and a comprehensive classification scheme.
3. Choose relevant analogues. Focus on addressing issues that are critical to an impending decision rather than "look-alike" or geographically close analogues.
4. Benchmark targets or characterize analogues. Place the prospect or asset in question in context of the probabilistic distribution of parameter values for the selected set of analogues to discover critical issues and reveal value creation opportunities.
5. Identify best practices. Analyze specific geological, engineering, and production parameters relevant to the critical issues identified and scrutinize potential solutions from best-in-class analogues (analogues that have a relatively high recovery

Table 2. Knowledge Standardization of Important Parameters for the Captain Field, United Kingdom, Central North Sea

Parameter Category	Standardized Value
1. Field	
Field name	Captain
Country	United Kingdom
Basin alias	North Sea Central
Onshore or offshore	Offshore
Water depth, ft	344
2. General	
Reservoir unit	Valhall (Captain Sandstone)
Hydrocarbon type	Oil with gas
Current status	Secondary recovery
Reservoir temperature, °F	87
Original reservoir pressure, psi	1340
Pressure gradient, psi/ft	0.45
Drive mechanisms	Strong aquifer
3. Well	
Total producers	54
Total injectors	10
Well type	Extended-reach well, horizontal well, multilateral well
Well spacing (current), ac	90
Well EUR, thousand bbl of oil	6100
4. Trap	
Tectonic setting	Postrift sag
Trapping mechanism	Buried-paleorelief compaction anticline, lateral depositional pinch-out
Seismic anomaly	None
Structural compartment count	2
Depth to top of reservoir, ft TVDML	2254
Trap flank dip (average), °	3
Original productive area, ac	9400
Oil column height, ft	269
5. Reservoir	
Reservoir age	Early Cretaceous
Tectonic setting	Postrift sag
Depositional environment	Submarine fan channel
Reservoir thickness gross (average), ft	280
Reservoir thickness net (average), ft	266
Net-to-gross ratio (average)	0.95
Net pay (average), ft	246
Reservoir lithology	Sandstone
Porosity matrix (average), %	31
Permeability air (average), md	7000
Vertical to horizontal permeability ratio (average)	0.2
Permeability contrast (average)	10
6. Fluid	
API gravity (average), ° API	20
Viscosity (average), cP	88
Mobility index (average), md/cP	80

(*continued*)

Table 2. Continued

Parameter Category	Standardized Value
Flowability (average), md·ft/cP	19,573
Original oil saturation (average), %	84
Formation volume factor oil (average), RB/STB	1.05
Bubble point pressure (average), psi	1270
Initial GOR (average), SCF/STB	130
Initial water saturation (average), %	16
7. Resource	
Original oil in place, million bbl of oil	1000
Resource density oil, thousand bbl of oil/ac	106
EUR oil, million bbl of oil	340
Estimated ultimate recovery factor, %	34
8. Improved recovery	
Secondary recovery methods	Continuous water injection
EOR methods	Polymer flood
Reservoir management practices (drilling)	Horizontal well, infill drilling, step-out drilling, sidetracking, extended-reach well, multilateral well
Reservoir management practices (sand control)	Stand-alone sand screen, open-hole gravel pack, prepacked sand screen
Reservoir management practices (artificial lift)	Electric submersible pump

Abbreviations: EUR = estimated ultimate recovery; GOR = gas–oil ratio; RB = reservoir barrel; SCF = standard cubic feet; STB = stock tank barrel; TVDML = true vertical depth below mudline.

efficiency for comparable rock and fluid properties, reservoir heterogeneity, and drive mechanism).

This workflow is demonstrated here using three case studies from across the E&P life cycle.

EXPLORATION APPLICATIONS

Subsurface geological analogues should form an integral part of the prospect maturation workflow to help reduce exploration uncertainty. Although individual plays and prospects are never identical, key learnings can be transferred both within and between basins, and therein lies the power of analogues. Commercially successful analogue fields can be used to both develop new ideas in mature basins and in the application of established ideas to frontier basins. "Discovery thinking" requires an open mind supported by detailed global knowledge of what is possible and what is proven.

When a prospect is being matured, geoscientists need to have confidence in the various technical parameters, which typically provide the basis for a drilling proposal. A common question decision-makers pose is, "Where are the successful analogues and how does this prospect compare to these analogues?" Benchmarking of prospects against commercially successful analogue fields allows inherent risks to be identified and managed and potential resource to be predicted with a higher degree of confidence. With the ability to search trends across similar plays, geoscientists can test if their play concepts are valid and calibrate the uncertainty ranges for various aspects of their geological model.

Misuse of Jubilee as an Analogue

Since the discovery of the Jubilee field in deep-water offshore Ghana in 2007, the industry has drilled numerous dry wells in the western Africa transform margin region. Several noncommercial discoveries have been made at the cost of hundreds of millions of dollars. All too often, those using Jubilee as an analogue assumed that Jubilee was a relatively simple upslope depositional pinchout trap supported by a

Table 3. Analogue Search Best Practices Illustrating Problems of Differing Nature and for Different Objectives Require Different Sets of Analogues

Exploration Geoscience

Play concept & prospect uncertainty range

- Tectonic setting
- Depositional environment or lithology
- Trapping mechanism
- Geologic age

Development Geoscience

Reservoir heterogeneity & connectivity

- Depositional environment
- Fluid flow restriction
- Diagenetic reservoir type
- Net-to-gross ratio

Production Management

Best practices and solutions to specific production challenges

- Hydrocarbon type
- Onshore or offshore
- Depositional environment or lithology

Benchmarking reservoir-level parameters, production performance and recovery factor reveals critical issues and value creation opportunities.

Subsearch and analysis on the critical issues identify best practices and potential solutions from best-in-class analogues.

Reservoir Engineering

Producibility, recovery and/or development options

- Hydrocarbon type
- Depositional environment or lithology
- Air permeability, API gravity and viscosity
- Onshore or offshore
- Drive mechanism
- Field size

brightening of amplitudes within the assumed container (Jewell, 2011). However, the single most important element in exploring for pure stratigraphic traps is the correct identification and quantification of seal (Dolson et al., 2018). An imperfect seal will change a very promising amplitude-based prospect into a dry well or a subcommercial discovery.

Generally, in stratigraphic traps, the overall size of the accumulation is limited by the column height capacity versus structural dip (Dolson et al., 2018). In most cases, this means that the steeper the structural dip, the more limited the trap size becomes. To understand the true nature of hydrocarbon entrapment for the Jubilee field, analogue selection is focused on rift and passive margin settings for (1) pure lateral pinchout trap and (2) normal-fault trap. Figure 4A shows trap flank dip versus productive area for 18 pure lateral pinchout traps in rift and passive margin settings. Jubilee, with a productive area of 19,244 ac and trap flank dip exceeding 5°, lies outside the maximum productive area limit for a given trap flank dip. In fact, all seven analogous reservoirs with trap flank dip exceeding 3° have a productive area less than 9000 ac, indicating Jubilee is less likely to be a pure lateral pinchout trap (being at the extreme of the distribution). In contrast, when benchmarking Jubilee against 226 normal-fault traps in rift and passive margin settings, it lies within the normal range of probabilistic distribution (Figure 4B), indicating Jubilee is more likely to be a combination trap with upslope faulting being an important factor in trap formation. Dailly et al. (2012) noted that the Turonian reservoirs appear to be trapped against a downthrown fault toward the northeast. Faulting seems to have been an important factor in trapping hydrocarbons for many lateral depositional pinchout traps in passive margin and rift settings and for upslope turbidite reservoirs (Amy, 2019).

As previously discussed, it is important to consider that only information from appropriate analogues is useful and that information from inappropriate analogues can be misleading. The misuse of Jubilee as an analogue for pure upslope depositional pinchout traps emphasizes the dangers of a misleading comparison. Along the western Africa transform margin, the assumption that Jubilee was a pure stratigraphic trap combined with the lack of recognition of the definitive updip fault seal led to many of the dry holes and subcommercial discoveries such as Narina-1 (2012), Mesurado-1 (2016), Fatala-1 (2017), and Ayame-1X (2017).

DEVELOPMENT APPLICATIONS

During appraisal and early field development, there are many uncertainties regarding the geologic model,

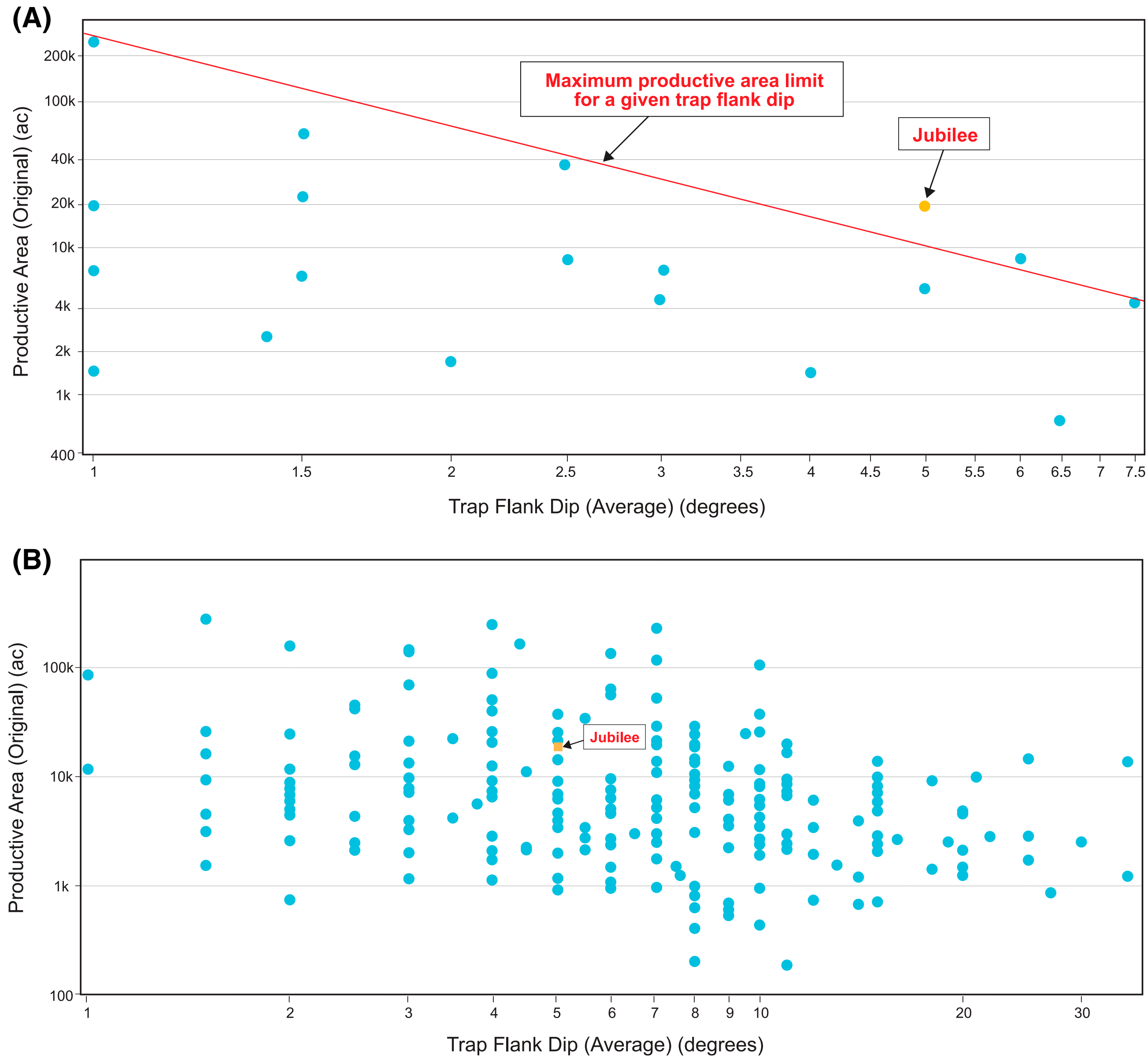

Figure 4. Trap flank dip versus productive area for hydrocarbon accumulation in rift and passive margin settings: (A) pure lateral depositional pinchout trap and (B) normal-fault trap.

number of wells needed to efficiently produce from a reservoir, well placement, pressure maintenance, recovery efficiency, and potential reservoir management programs. Comparing new discoveries with analogous producing reservoirs helps better estimate recoverable reserves and future production performance and therefore optimizes recovery methods.

When using analogues for assessing field development scenarios, detailed knowledge on reservoir heterogeneity and connectivity, well type, spacing and rate, estimated ultimate recovery (EUR) per well, rock and fluid properties, drive mechanism, recovery methods, and field size is required. Benchmarking undeveloped discoveries using these variables can identify best practices to help plan an optimal hydrocarbon recovery strategy and give greater confidence in estimating production rates and recovery factors.

Development Concept for Zama Discovery

Talos Energy and partners Premier Oil and Sierra Oil and Gas announced a world-class oil discovery at the Zama prospect, offshore Mexico. The Zama

Table 4. Knowledge Standardization of Key Geological and Engineering Parameters for the Zama and Amal Fields

Parameter Category	Standardized Value	Standardized Value
1. Field		
Field name	Zama	Amal
Country	Mexico	Libya
Discovery year	2017	1959
First production year	2022	1966
Current status	Appraisal	Secondary recovery
Onshore or offshore	Offshore	Onshore
Water depth, ft	546	Not applicable
2. Reservoir general		
Hydrocarbon type	Oil	Oil
Original reservoir pressure, psi	Not available	4675
Pressure gradient, psi/ft	Not available	0.47
Drive mechanisms (main)	Not available	Aquifer drive
3. Well		
Total producers	Not available	175
Total injectors	Not available	4
Well type	Not available	Vertical or deviated well
Well spacing, ac	Not available	210
Initial well rate oil, BOPD	Not available	16,778
Well EUR, thousand bbl of oil	Not available	6183
4. Trap		
Tectonic setting	Salt	Rift
Trapping mechanism	Diapiric piercement	Paleostructural subcrop
Seismic anomaly	AVO anomaly	None
Structural compartment count	Not available	3
Depth to top of reservoir, ft TVDML	11,000	9655
Trap flank dip average, °	Not available	2
Original productive area, ac	3200	156,900
Hydrocarbon column height, ft	3018	720
5. Reservoir		
Reservoir unit	Zama Sandstone	Amal–Maragh
Reservoir age	Late Miocene	Cambrian–Triassic, Cretaceous
Depositional environment	Submarine fan	Braided river
Gross reservoir thickness (average), ft	1676	570
Net reservoir thickness (average), ft	1173	Not available
Net-to-gross ratio (average)	0.7	Not available
Net pay (average), ft	607	Not available
Reservoir lithology	Sandstone	Sandstone
Matrix porosity (average), %	25	14
Air permeability (average), md	450	1
6. Fluid		
API gravity (average), ° API	29	36
Initial GOR (average), SCF/STB	450	444
7. Resource		
Original oil in place, million bbl of oil	1400–2000	5000
EUR, million bbl of oil	400–800	1082
Estimated ultimate recovery factor, %	Not available	22

Abbreviations: AVO = amplitude versus offset; EUR = estimated ultimate recovery; GOR = gas–oil ratio; SCF = standard cubic feet; STB = stock tank barrel; TVDML = true vertical depth below mudline.

Table 5. List of Reservoir Analogues with Critical Parameters for the Understanding of Zama Development Concept

Field Name	Reservoir Unit Name	Country	Hydrocarbon Type	Air Permeability (Average), md	Viscosity, cp	Net Pay (Average), ft	Drive Mechanism Main	Ultimate Recovery Factor, %
Agbami	Akata (13–18 m.y.)	Nigeria	Oil only	270	0.26	Not available	Solution gas	48
Albacora	Carapebus	Brazil	Oil only	1000	26.5	Not available	Solution gas	35
Atlantis	Middle Miocene Sands	United States	Oil only	1000	Not available	312	Moderate aquifer	25
Balder	Heimdal–Hermod–Balder	Norway	Oil with gas	6000	3.5	82	Strong aquifer	48
Barracuda	Marlim-10	Brazil	Oil only	1000	2.85	67	Solution gas	44
Belayim Marine	Rudeis–Kareem	Egypt	Oil only	400	1.12	Not available	Strong aquifer	46
Buzzard	Buzzard Sandstone	United Kingdom	Oil only	1900	Not available	Not available	Solution gas	58
Carpinteria	Pico (Repettian Stage)	United States	Oil only	550	8	350	Moderate aquifer, solution gas	Not available
Claymore	Claymore Sandstone	United Kingdom	Oil only	150	4.75	518	Weak aquifer, solution gas	42
Foinaven	Vaila	United Kingdom	Oil with gas	800	4	Not available	Unknown aquifer drive strength	35
Forties	Forties	United Kingdom	Oil only	700	0.76	Not available	Strong aquifer	62
Girassol	Malembo (B Sand System)	Angola	Oil only	4200	1.1	300	Weak aquifer	47
Jubilee	Mahogany Sand	Ghana	Oil only	300	0.23	149	Gravity drainage	40
Magnus	Magnus Sandstone	United Kingdom	Oil only	350	0.3	213	Solution gas	54
Mars	D-T1 Sands	United States	Oil only	311	Not available	440	Compaction	26
Miller	Brae	United Kingdom	Oil only	100	0.2	Not available	Weak aquifer, solution gas	56
Namorado	Namorado	Brazil	Oil only	300	1.57	Not available	Weak aquifer, solution gas	59
Nelson	Forties	United Kingdom	Oil only	200	Not available	Not available	Strong aquifer	61
Roncador	Carapebus	Brazil	Oil with gas	800	10	520	Solution gas, gas cap expansion	28
Schiehallion	Vaila	United Kingdom	Oil with gas	1250	3	Not available	Solution gas	35
Thunder Horse	Pink–Brown–Peach (Ths)	United States	Oil only	770	Not available	390	Strong aquifer	27
West Seno	Upper Miocene	Indonesia	Oil with gas	360	2.1	226	Solution gas	25

discovery was made in upper Miocene submarine fan sandstone reservoirs with a three-way dip structure sealed against a salt ridge (Offshore Technology, 2017). The field's estimated stock tank oil initially in place (STOIIP) ranges from 1.4 to 2 billion BOE, and it has estimated recoverable reserves of 400–800 million bbl of oil (Offshore Energy Today, 2019). Analogues for the Zama discovery were used to provide benchmarks for recovery factor and development concepts with the aim to increase the ultimate recovery. In light of the previously described workflow, the following four steps were taken to analyze the Zama discovery.

1. Defining problems and objectives: What is the recovery potential of the Zama discovery? How many wells are needed to efficiently produce from the reservoir? What is the possible reservoir management program to consider?
2. Capturing knowledge: Based on press releases from the operator, both the text and numeric parameters have been standardized and classified using consistent rules and a holistic classification scheme (Table 4).
3. Analogue selection: In light of the principal objective to understand recovery potential and evaluate development scenarios, the recommended analogue selection focuses on hydrocarbon type (oil), development situation (offshore), depositional environment (submarine fan), API gravity (>22°), air permeability (>100 md), and original oil in place (>500 million bbl of oil) as the critical search parameters. Twenty-two applicable global analogues are identified using search criteria relevant to the Zama development concept (Table 5).
4. Analysis and insights: Using this method, several insights can quickly be developed from the probabilistic distribution of analogue data, including well spacing, initial well rate, EUR per well, plateau annual recovery, and recovery factor (Table 6). Applicable global reservoir analogues show that the mean recovery factor achieved is 42%, but the upper range exceeds 60% (Table 5). Higher recovery factor tends to be associated with good air permeability, relatively thick net pay, and lower viscosity (Table 5). For those fields that have exceeded 50% ultimate recovery (e.g., Buzzard, Forties, Magnus, Miller, and Nelson fields, United Kingdom, and Namorado field, Brazil), continuous water injection and conformance improvement techniques, such as water plugging, modifying injection pattern, and profile modification, have proved to be effective in optimizing the recovery (Table 7). Benchmarking of recovery efficiency against empirical recovery chart (Tong, 1988) demonstrates maximizing recovery efficiency during the low water-cut period (water cut <25%) is critical to optimizing the ultimate recovery (Figure 5). All fields with higher than 50% recovery factor have adopted effective reservoir management practices, such as horizontal wells, sand control, artificial lift, and well treatment (Table 7). Considering all these factors, there is a strong likelihood the published recoverable reserves of 400–800 million bbl of oil may have significant upside.

Table 6. Analogue Characterization for the Zama Development Concept: Probabilistic Distribution of 90% to 10% Range of Analogues for the Key Numeric Parameters

Numeric Parameter	Mean	P90–P10 Range of Analogues		
		P90	P50	P10
Well spacing, ac	182	22	170	381
Initial well rate, BOPD	10,755	2412	7542	25,200
Well EUR, million bbl of oil	23	11	14	47
Plateau annual recovery, % of oil in place	3.2	1.6	2.9	5.5
Plateau annual recovery, % of EUR	7.8	4.6	6.8	12
Ultimate recovery factor, %	42	26	43	60

Abbreviations: EUR = estimated ultimate recovery; P10 = estimate exceeded with 10% probability; P50 = estimate exceeded with 50% probability; P90 = estimate exceeded with 90% probability.

Table 7. Analogue Characterization for the Zama Development Concept: Reservoir Management Best Practices for Fields with >50% Ultimate Recovery Factor

Reservoir Management Best Practices	First	Second	Third
Secondary recovery method	Continuous water injection	–	–
Conformance improvement	Water plugging	Modifying injection pattern	Profile modification
Drilling	Horizontal well	Infill drilling	–
Sand control method	Stand-alone sand screen	Hydraulic fracturing and gravel packing	Case-hole gravel pack
Artificial lift	Gas lift	ESP	–
Well treatment	Scale inhibitor treatment	Sand cleaning	Wax removal

Abbreviation: – = none; ESP = electric submersible pump.

PRODUCTION APPLICATIONS

Globally, billions of barrels of oil can be monetized through the application of improved and enhanced recovery techniques as demonstrated by the successful polymer flood of several offshore giant fields (e.g., Captain field, United Kingdom, and Suizhong 36-1 field, China). Information derived from the use of appropriate analogues comprising the most successfully developed fields can help rejuvenate production and maximize ultimate recovery. Identifying opportunities for reserve growth requires a detailed knowledge of what the most efficient producers are doing under comparable geologic and engineering circumstances. Analogues can help determine which improved and enhanced oil recovery techniques are likely to be most efficient for a given reservoir. Benchmarking of geologic-engineering attributes, production performance, and recovery factor against global analogues can help discover critical issues and reveal new opportunities for improvement. Further analysis of the critical issues can help identify the best-performing analogues, lessons learned, and potential solutions to the specific production challenges.

Analogue intelligence has proven to be a powerful method to screen investment opportunities in mature (or even abandoned) fields. Specific technologies, such as horizontal and multilateral drilling,

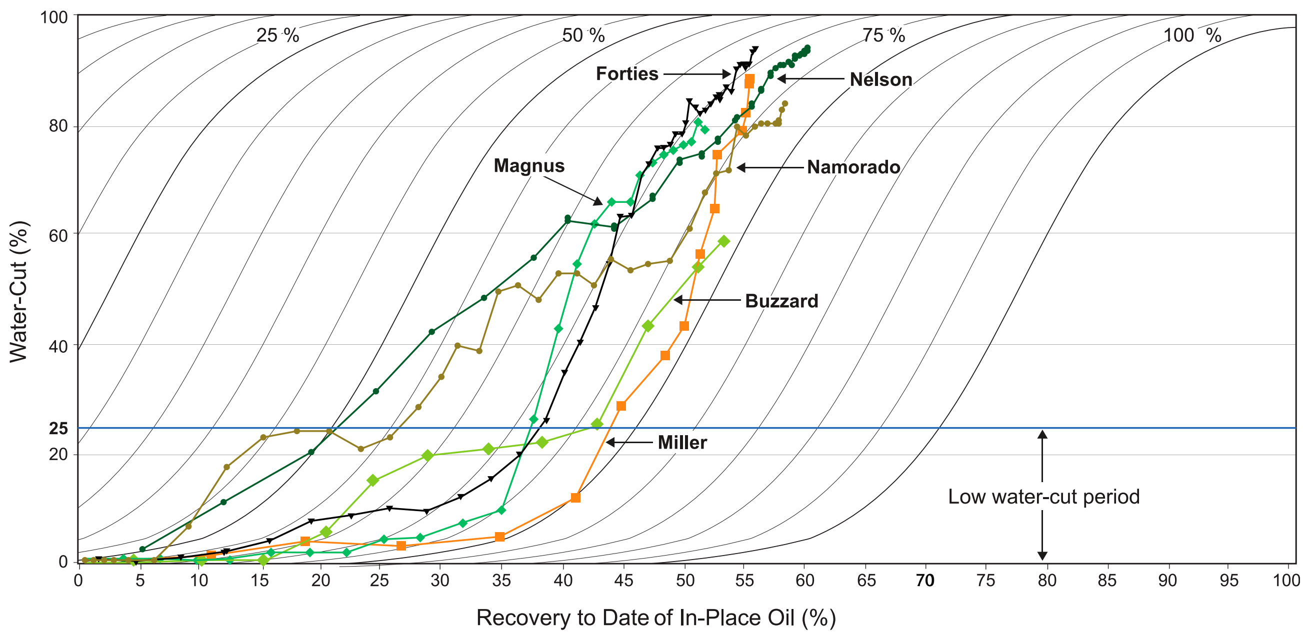

Figure 5. Recovery efficiency against the empirical recovery chart (Tong, 1988) for the Zama development analogues with >50% ultimate recovery factor. Maximizing recovery efficiency during the low water-cut period is critical to optimizing the ultimate recovery.

underbalanced drilling, or gravity-assisted thermal recovery, can be applied to reservoirs with appropriate geological and engineering parameters from analogue fields. This methodology improves decision quality and drives value and is herein demonstrated through a case study of Amal field, onshore Libya.

Redevelopment Opportunities for Amal Field

The Amal field, onshore Libya, has estimated STOIIP of 5 billion bbl and a very large productive area of 156,900 ac and produces from a tight sandstone reservoir with an average permeability of 1 md. After more than 45 yr of production, it has only recovered 18% of STOIIP (Figure 6A), while the majority of resources remain in the ground (Table 4). The analogue workflow recommended herein was employed to review the Amal field and benchmark its recovery factor against applicable global analogues to identify the best practices of fields with better and more efficient recovery. As with the other examples presented here, the workflow followed was as follows:

1. Defining problems and objectives: Given the production challenge of low reservoir permeability, what is the upside potential for Amal redevelopment? What ideas could be implemented from fields with similar production challenges?

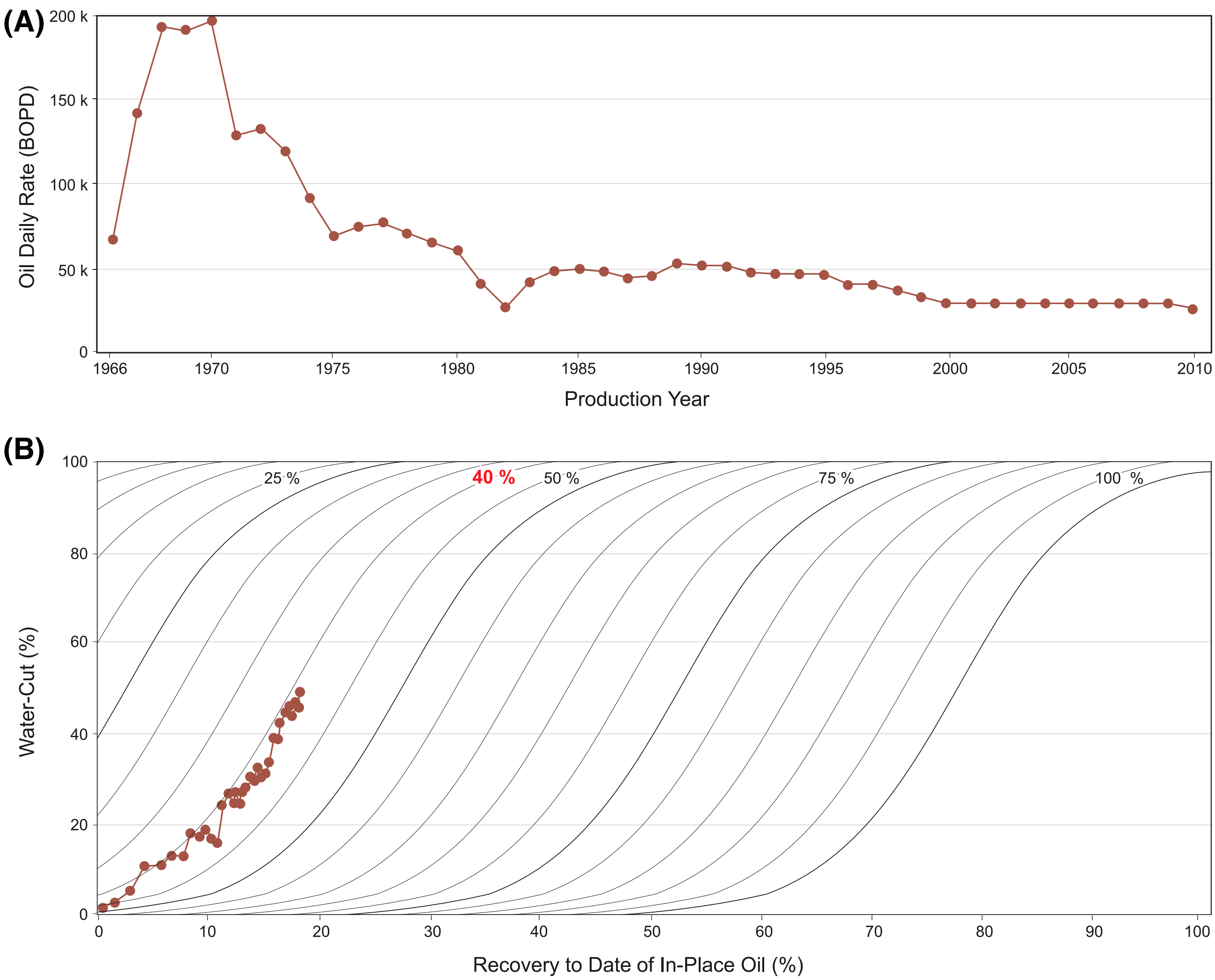

Figure 6. Production performance of the Amal field, onshore Libya: (A) production history curve (1966–2010) and (B) recovery efficiency against empirical recovery chart (Tong, 1988). Amal field lies along 40% of the ultimate recovery trend, indicating the field has potential to recover 40% of stock tank oil initially in place given its rock and fluid properties, drive mechanism, and reservoir conditions.

Table 8. List of Reservoir Analogues with Critical Parameters for the Identification of Amal Redevelopment Opportunity

Field Name	Reservoir Unit Name	Country	Hydrocarbon Type	Air Permeability (Average), md	Viscosity, cp	Net Pay (Average), ft	Drive Mechanism Main	Ultimate Recovery Factor, %
Ahwaz	Asmari	Iran	Oil with gas	10	0.58	430	Strong aquifer	48
Alpine	Alpine Sandstone	United States	Oil only	15	0.45	50	Solution gas	50
Altamont–Bluebell	Green River and Colton/Wasatch	United States	Oil only	0.1	Not available	575	Solution gas	12
Ansai	Yanchang	China	Oil only	2	2	46	Solution gas	25
Barrow Island	Windalia sand	Australia	Oil with gas	2.5	1.76	Not available	Solution gas, gas cap expansion	27
Bitkiv–Babche	Menilite	Ukraine	Oil with gas	5	1.3	766	Moderate aquifer	14
Borislav	Menilite–Popel–Wytwycia –Jamna–Stryj	Ukraine	Oil only	5.5	4	169	Unknown aquifer drive strength	39
Chaoyanggou	Fuyu (Quantou)	China	Oil only	11.3	10.4	29	Solution gas	21
Chicontepec	Chicontepec	Mexico	Oil only	1	5	Not available	Solution gas	8.5
Dolin	Wyhoda–Bystrycia –Maniava–Menilite	Ukraine	Oil only	13	1	289	Moderate aquifer	34
Hassi Messaoud	Zone Ra	Algeria	Oil only	5	0.21	210	Solution gas	24
Luginets	Tyumen-Naunak	Russia	Oil with gas	20	0.3	Not available	Solution gas, gas cap expansion	26
Nakhla	Upper Sarir	Libya	Oil only	1.4	0.35	260	Solution gas	Not available
North Ward Estes	Yates	United States	Oil with gas	19	1.4	100	Solution gas	40
Orocual	San Juan	Venezuela	Oil with gas	5	Not available	520	Solution gas	Not available
Priob	Achimov–Vartov	Russia	Oil only	3.6	1.93	131	Weak aquifer	28
Rangely	Weber sandstone	United States	Oil with gas	8	1.7	189	Solution gas, unknown aquifer drive strength	51
Rhourde El Baguel	Cambrian	Algeria	Oil only	5	1.55	902	Solution gas	32
Rostovtsev	Novy Port	Russia	Oil with gas-condensate	6	Not available	Not available	Solution gas, gas cap expansion	33
Spraberry Trend	Spraberry–Dean	United States	Oil only	0.3	0.7	70	Solution gas	15
Vakh	Naunak	Russia	Oil only	16	1.15	52	Solution gas	33

Table 9. Analogues to Understand the Production Challenge for the Amal Field: Key Numeric Parameter Values of Target Reservoir Against Probabilistic Distribution of 90% to 10% Range of Analogues

		P90–P10 Range of Analogues		
Numeric Parameter	Amal Field Value	P90	P50	P10
Productive area, ac	156,900	11,000	56,735	1,197,118
Total producers	175	18	471	3344
Well spacing, ac	210	9.5	46	280
Air permeability, md	1	0.8	5	17
Ultimate recovery factor, %	22	13	28	49

Abbreviations: P10 = estimate exceeded with 10% probability; P50 = estimate exceeded with 50% probability; P90 = estimate exceeded with 90% probability.

2. Capturing knowledge: Based on public domain data sources, both the text and numeric parameters have been standardized and classified using consistent rules and a comprehensive classification scheme (Table 4).
3. Analogue selection: Since the main objective in this case is to identify best practices and optimal solutions to the production challenges of a mature asset, analogue selection is therefore focused on hydrocarbon type (oil), development situation (onshore), reservoir lithology (sandstone), air permeability (<20 md), API gravity (>22°), and original oil in place (>500 million bbl of oil) as the critical search parameters. Twenty-one applicable global analogues were selected using search criteria relevant to the Amal redevelopment challenges (Table 8).
4. Analysis and insights: Analysis of recovery efficiency using the empirical recovery chart, which describes the relationship between ultimate recovery, recovery to date, and water cut (Tong, 1988), indicates that an ultimate recovery factor of 40% could be possible for the Amal field (Figure 6B). Benchmarking of Amal field's geologic-engineering parameters against applicable global analogues reveals several critical issues, including selection of a very large well spacing (i.e., small number of producers for its very large productive area) and poor recovery efficiency (Table 9). In addition, the field has adopted few modern reservoir management practices. The poor reservoir quality and weak natural energy drive for the analogous reservoirs mean application of improved recovery techniques and adoption of good reservoir management practices are critical to optimize the ultimate recovery of the low-permeability sandstone reservoirs. Data from analogue fields with more than 30% ultimate recovery suggest several successful secondary methods, including continuous water injection, hydrocarbon gas injection, and water-alternating-gas (WAG) immiscible injection, and conformance improvement techniques,

Table 10. Analogues to Understand the Production Challenge for the Amal Field: Reservoir Management Best Practices for Fields with >30% Ultimate Recovery Factor

Reservoir Management Best Practices	First	Second	Third
Secondary recovery method	Continuous water injection	Hydrocarbon gas injection	WAG immiscible injection
Enhanced oil recovery method	WAG miscible flood	CO_2 miscible flood	Hydrocarbon miscible flood
Conformance improvement	Modifying injection pattern	Profile modification	Zonal injection
Drilling	Horizontal well	Infill drilling	–
Stimulation	Hydraulic fracturing	Matrix acidization	–
Artificial lift	Rod pump	Gas lift	ESP
Production optimization	Recompletion	Reperforation	Additional perforation
Well treatment	Scale inhibitor treatment	Corrosion inhibitor treatment	–

Abbreviations: – = none; ESP = electric submersible pump; WAG = water-alternating-gas.

such as modifying injection pattern, profile modification, and zonal injection (Table 10). The WAG miscible flood and CO_2 miscible flood have also been successfully applied to several fields that have achieved higher recovery, such as Alpine, North Ward Estes, and Rangely fields, United States. Reservoir management best practices from those fields with more than 30% ultimate recovery include horizontal wells, infill drilling, hydraulic fracturing, matrix acidization, artificial lift, production optimization, and well treatment (Table 10). This analogue-based analysis allows the operator to evaluate the cost of improved recovery programs against the value of the potential remaining recoverable reserves and resources to more accurately determine the economic viability of this field redevelopment opportunity.

CONCLUSION

Global analogues have wide application in supplementing the technical understanding of geoscientists, reservoir engineers, and decision-makers working across the E&P life cycle. Analogues have specific application to new ventures, prospect generation, risk assessment, reserves booking, field development, production operations, and portfolio management. Properly selected analogues serve to constrain interpretations, inform choices and decisions, and benchmark asset performance. The power of analogues for both geoscientists and engineers stems from expanding knowledge from being colloquial, to a broader stance, derived from sources beyond individual or team experience. Rather than relying upon a single analogue or geographically close analogues, we recommend a comparison to a group of genetically related analogues to understand the full range of uncertainty. The value of global analogues can only be realized through the development of a coherent and consistent knowledge base and within a structured and classified knowledge framework. The ability to apply global analogues to a local situation can help add an additional dimension of creativity and confidence to E&P decision-making for the following applications:

Generate new exploration ideas: Identify most likely play and trap types in basins of interest and demonstrate what success looks like through understanding analogous discoveries; broaden the knowledge and experience base of individuals and teams, opening explorers' minds as to what is possible.

Reduce exploration uncertainty: Calibrate prospect uncertainty ranges using key facts from commercially successful fields and deliver more confidence in prospect evaluation.

Validate development concepts: Subsurface analogues provide an objectivity basis on which to test the viability of field development scenarios and characterize permissible alternatives of a geologic model.

Evaluate opportunities for redevelopment: Understand the primary controls on recovery efficiency, test these against global best practices for recovery improvement, and use this knowledge to guide redevelopment and optimization of existing assets.

Benchmark production performance and recovery factor: Identify applicable global analogues to facilitate comparison of field performance against what is possible, understand what the best-performing analogues have done to maximize production efficiency, and establish recovery factor trends for a specific portfolio theme.

Rank the portfolio of your assets: Build a reservoir knowledge base unique to your portfolio; classify an existing portfolio of prospects, assets, or both; and identify portfolio issues and spotlight the best opportunities for value creation.

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