C&C Reservoirs

Analogue Benchmarking Solution to Maximize Hydrocarbon Recovery

SPE Webinar

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D·A·K·S 5.0 Analogue intelligence for better decision-making

Key Challenge E&P Companies Are Facing Today

"We are **drowning in information, while starving for wisdom**.
The world henceforth will be run by synthesizers, people able to put together the right information at the right time, think critically about it, and make important choices wisely."

Edward O. Wilson - American biologist, researcher, author

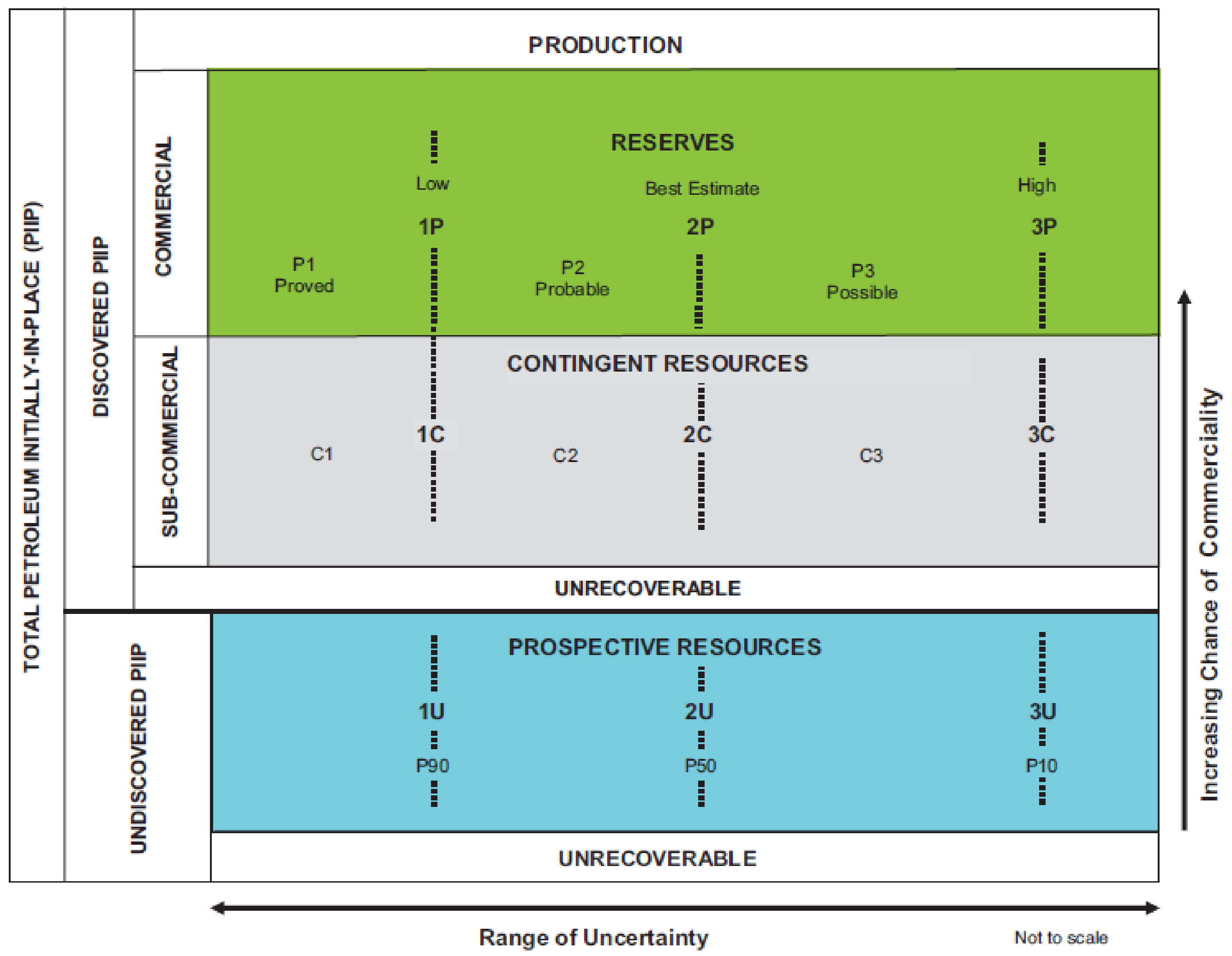
Why Analogues?

Analogues provide the opportunity to learn from local and global experience and generate more insightful and creative ideas, from which better decisions can be made

- Provide input when data are not yet available for new assets
- Calibrate uncertainty range
- Validate ideas, concepts or assumptions
- Help identify issues & opportunities to maximize asset value

Analogue Intelligence combined with your own data and technology results in superior decision making, driving value

Analogue Methods Form an Integral Part of Resource Quantification



- **"Analogues** are widely used in the estimation of resources, particularly during exploration and appraisal phases when information from direct measurement is limited."
- **"Analogues** are frequently used in the assessment of economic producibility, production decline characteristics, drainage area, and recovery factor (for primary, secondary, and tertiary methods)."
- "Comparison to several **analogues**, rather than a single **analogue**, is necessary to understand the full range of uncertainty in the estimated recoverable."

SPE, WPC, AAPG, SEG, SPWLA & EAGE, 2018. Petroleum Resources Management System (2018 version). Society of Petroleum Engineers.

Common Pitfalls and Mistakes of Analogue Application

Most of inappropriate application of analogue analysis result from a lack of structured, standardized and classified analogue knowledge framework

- Local analogues are necessary, but unable to help generate new ideas or capture the full uncertainty range
- When global analogues are in conflict with local data, users only select those analogues that confirm their preexisting belief
- Analogues are chosen arbitrarily, relying on project team's recommendation and knowledge from their own experience
- Analogues are chosen too specifically for "look-alike fields"

Analogue Definition and Selection

- Analogs are comparable fields or reservoirs relevant to a specific question or set of questions
- Finding relevant analogues for any specific questions is a process of empirical research - problems of differing nature and for different objectives require different sets of analogues
- Users should focus on their specific question(s) instead of “lookalike” or geographically close analogues
- The best practice starts with a broad set of parameters to find a wide range of analogues, then narrow the selection as appropriate to focus on the specific critical issues
- It is critical to strike an appropriate balance between the number and relevance of analogues

Analog Selection Best Practices

Exploration Geoscience

Play concept & prospect uncertainty range

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

Development Geoscience

Reservoir heterogeneity & connectivity

- Depositional environment
- Diagenetic reservoir type
- Compartmentalization
- Net to gross ratio

Reservoir Engineering

Producibility/recovery/development options

* Hydrocarbon type
* Depositional environment/lithology
* Rock and fluid properties
* Onshore/offshore
* Drive mechanism
* Field size

Production Management

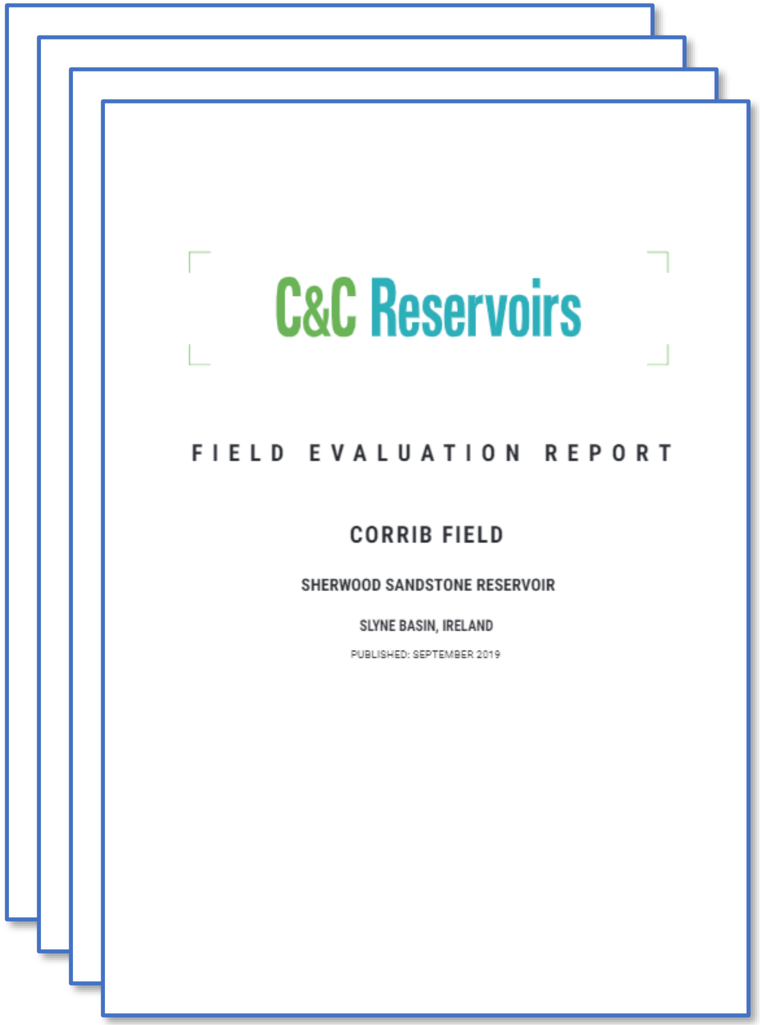
Best practices and Lessons Learned to Maximize HC Recovery

- Hydrocarbon type
- Onshore/offshore
- Depositional environment/lithology
- Rock and fluid properties

Benchmark comparison against relevant analogues to identify critical issues and upside recovery potential

Isolate specific critical issues and focus on a smaller number of applicable analogues with the aim to identify both best practices and lessons learned

C&C Reservoirs' Approach Since Early 1990s…


C&C Reservoirs

FIELD EVALUATION REPORT

CORRIB FIELD

SHERWOOD SANDSTONE RESERVOIR

SLYNE BASIN, IRELAND

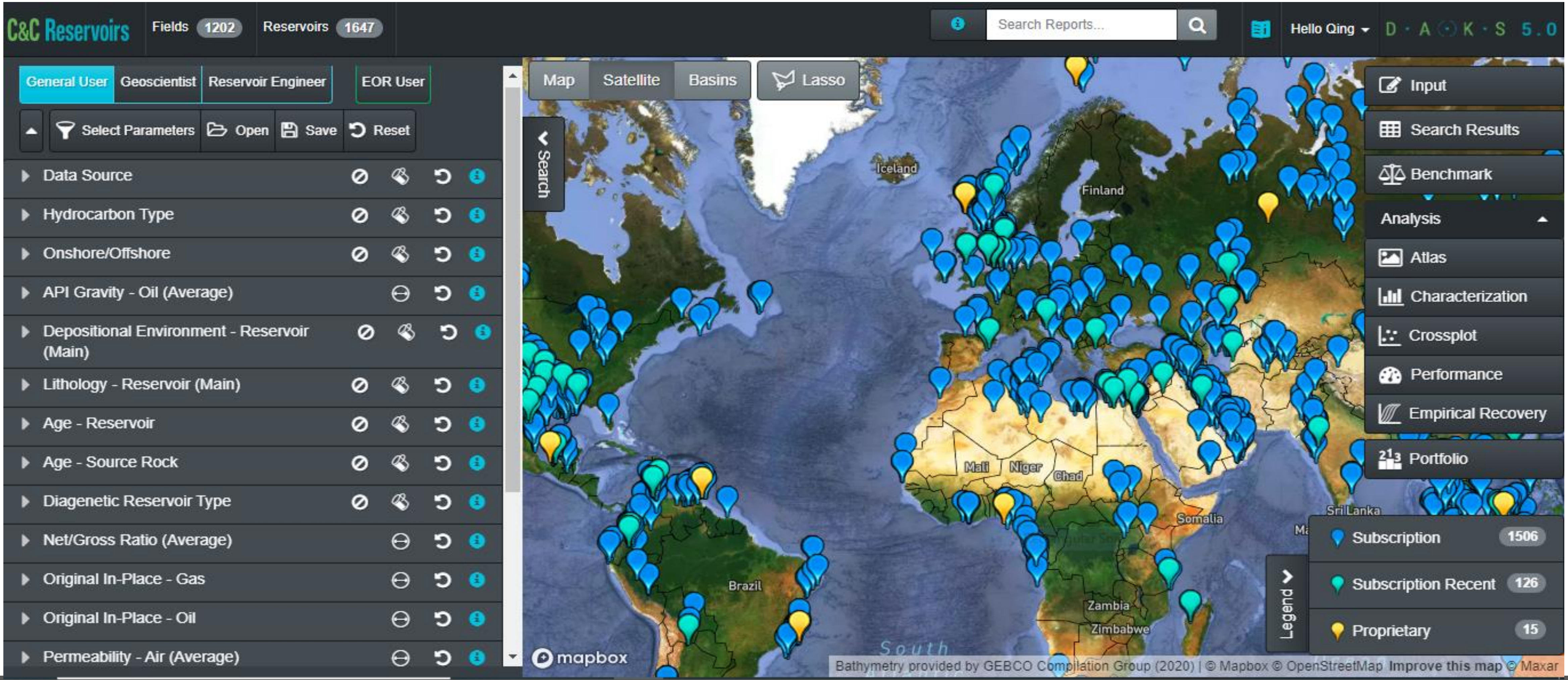
PUBLISHED: SEPTEMBER 2019

- Document **key facts, lessons learned and best practices** from the world's most important fields and reservoirs, and presented as Field Evaluation Reports
- Establish **rigorous standards, rules and comprehensive classification** to consistently capture reservoir and field knowledge and codify them into a coherent knowledge base
- Provide a **cloud-based software platform** that facilitates transformation of this knowledge base into real-time intelligence and insight

~70% of global conventional EUR hydrocarbon is documented by C&C's Field Evaluation Reports

Digital Analogue Knowledge System - DAKS

DAKS is a secure cloud-based, asset-centered, knowledge platform to improve decision quality and drive value throughout the E&P lifecycle, integrating users' expertise and knowledge on their E&P assets with global analog intelligence



Data Sources and Verification

- **C&C** started with a Joint Industry Project (JIP) led by Chevron during early 1990s. The objective was to analyze and document field and reservoir knowledge on 600 mature carbonate and clastic fields from the 10 JIP participating companies

- We frequently contacted these companies for review and validation of their reported data for the first 10 years of **C&C** history

- From then on, we relied on public domains, government agencies and regional data providers from different countries

- In-place volume, EUR, recovery factor and well EUR are usually derived from operators' or agencies' latest publications validated by up-to-date production data and decline curve analysis

Knowledge Integrity and Update

- Seasoned geoscientists and reservoir engineers with >20 years of experience with major operators
- Rigorous review, holistic classification and consistent rules/guidelines into knowledge standardization workflow
- Knowledge integration into comprehensive field evaluation and EOR reports and coherent context
- QA/QC analytics tools to identify outliers
- Annual update on production data and green fields, ongoing health check of data quality and consistency, rewriting brown fields in 5 years cycle and adding 30-50 new fields per year

Why Analogue Benchmarking?

Analogue benchmarking is a key step in field development optimization and a prerequisite in understanding the necessary actions required to maximize hydrocarbon recovery

- Quantify potential expected ultimate recovery
- Understand key controls on reservoir performance and recovery efficiency
- Identify best-in-class performers and examine in detail what differentiates them
- Replicate best practices employed at top-performing analogues
- Validate new opportunities for reserves growth

Difficulties in Existing Benchmarking Methods

- Published methods were developed for, and are therefore specific to, reservoirs in certain geological settings - e.g., Reservoir Complexity Index (RCI) by NPD or Field Quality Index(FQI) by OGA

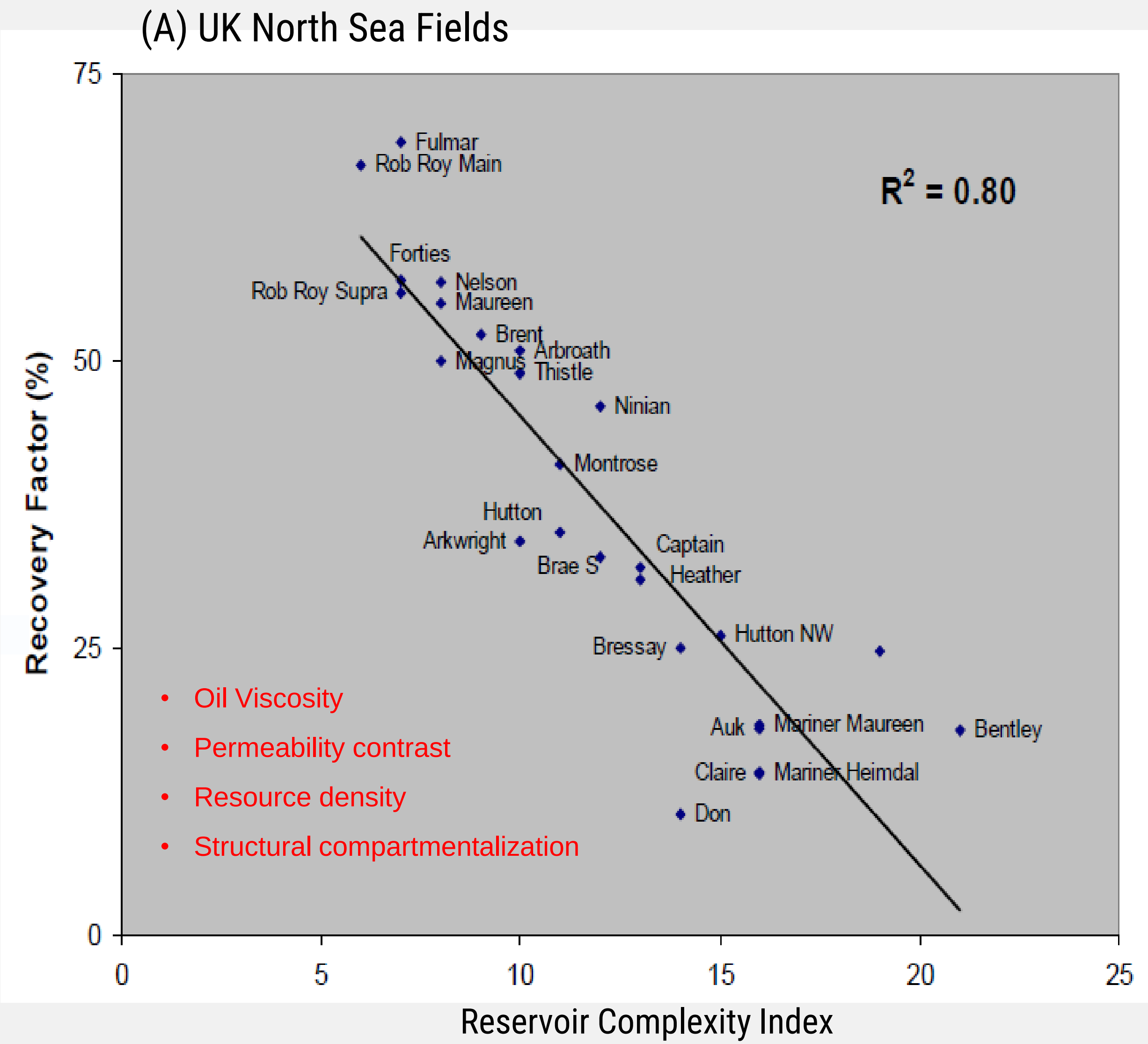
- Owing to a lack of consistency and objectivity in parameter selection, calculation and normalization, the RF trends established for individual scenarios can not be replicated elsewhere

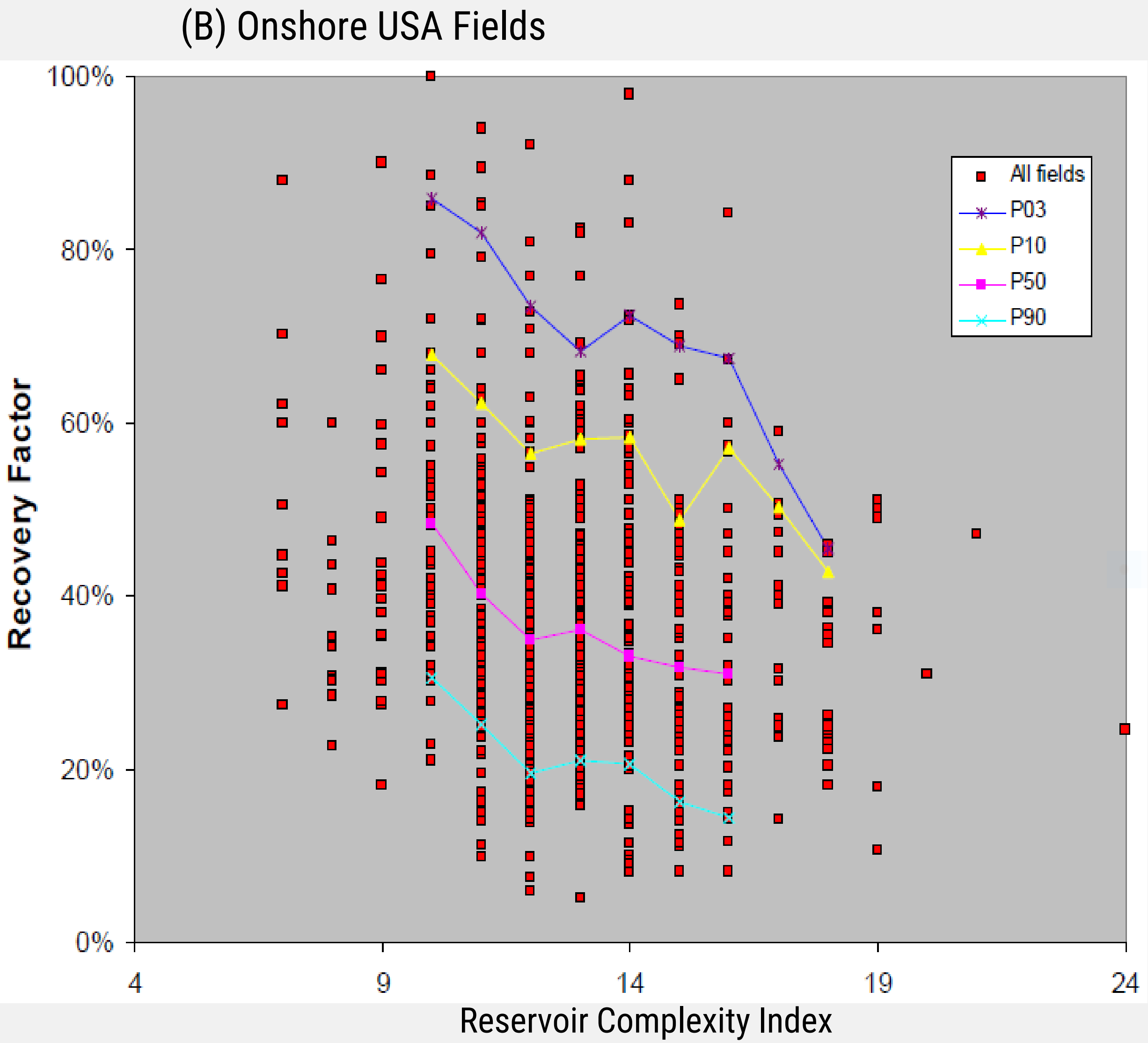
- Existing methodologies are biased towards certain geological and fluidic parameters specific to individual situations and thus do not account for other intrinsic properties that may have a large impact on recovery efficiency

- Existing methodologies are solely based on local analogues and do not leverage key learnings from applicable analogues on a global basis

- In contrast to other elements of petroleum resource quantification, such as prospect risking or process for resource estimation (Society of Petroleum Engineers, 2018), there is not a universally repeatable and standardized analogue benchmarking workflow

Reservoir Complexity Index vs Recovery Factor





Wickens, L.M. and Kelly, R. 2010 Rapid assessment of potential recovery factor: a new correlation demonstrated on UK and USA fields. SPE Annual Technical Conference and Exhibition, Florence, September 19-22, 2010, Italy, SPE-134450-MS

Our Approach to Analogue Benchmarking

Most of difficulties in existing methodologies result from the lack of a robust data model and absence of a holistic classification scheme

- Build a consistent reservoir knowledge base with standardized and classified geological and engineering parameters
- Develop an empirical analogue benchmarking workflow based on a proprietary compilation of >1600 global reservoirs
- Designed for effective, practical and repeatable application of analogue analysis to all reservoir types, development scenarios and production challenges
- Tested against carbonate, clastic and basement reservoirs globally
- Proved highly effective at quantifying resource potential, assessing production performance and identifying best practices and lessons learned

DAKS Analogue Benchmarking Workflow

1. Definition of Problems and Objectives	Define the specific problems to address and the critical questions to be answered
2. Parameterization of the Target Reservoir	Catalogue prospects and assets using consistent standards and a holistic classification scheme
3. Quantification of Resource Potential	Establish recovery factor trends using key intrinsic parameters that have major impact on recovery efficiency
4. Assessment of Production Performance	Analyze normalized production and injection performance data from applicable analogues
5. Identification of Best Practices & Lessons Learned	Isolate specific critical issues and focus on a smaller number of applicable analogues to identify both best practices & lessons learned

Definition of Problems and Objectives

- Expected ultimate recovery factor of the target reservoir based on analogue recovery factor trend and understanding of key controls on recovery efficiency
- Upside recovery potential of the target reservoir and best practices from the top-performing analogues
- Production performance of analogues and impact of water-cut on production behavior
- Current and likely future production performance of the target reservoir
- Well EUR and spacing, number of producers and annual plateau recovery of STOIIP required to achieve the expected ultimate RF and upside recovery potential
- Mitigation measures to optimize production and recovery of the target reservoir
- EOR method screening and performance evaluation of analogues
- Estimation of incremental recovery by infill drilling, secondary recovery and EOR methods
- Impact of effective reservoir management programs on production performance

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Parameterization of Target Reservoir

Text Parameter

- **Field and Reservoir General:** onshore or offshore, hydrocarbon type, original reservoir pressure and temperature, pressure gradient, current production stage and water-cut, and drive mechanism

- **Well:** well type, pattern and completion, no of producers and injectors, well spacing, initial and plateau rate and well EUR

- **Trap:** trapping mechanism, depth to top of reservoir, productive area, hydrocarbon column height

- **Reservoir and Fluid Properties:** reservoir age, depositional environment, lithology, diagenetic reservoir type, wettability, matrix or bulk porosity, air permeability, gross reservoir thickness, net pay, N/G ratio, API gravity, viscosity, mobility index, flowability, initial water saturation, gas specific gravity and condensate/gas ratio (CGR)

Parameterization of Target Reservoir

Text Parameter

- **Resource:** original in-place, resource density, EUR, recovery to date of in-place and EUR, and recovery factor (primary and ultimate)

- **Improved Recovery** (reservoir scale): secondary recovery and EOR methods, conformance improvement techniques

- **Improved Recovery** (well scale): drilling, stimulation, artificial lift, sand control, well productivity optimization, well treatment and workover

- **Improved Recovery** (incremental recovery): infill drilling, secondary recovery and EOR methods

- **Production performance:** production and injection rate, water-cut, pressure, GOR, annual recovery of in-place and EUR, recovery to date of in-place and EUR, voidage replacement ratio (VRR), and injected pore volume (PV) or hydrocarbon pore volume (HPV)

Parameterization of Target Reservoir - Dan Field Example (~ 60 parameters)

Paramater Category	Standardized Value
1. FIELD	
Field Name	Dan
Country	Denmark
Basin Name	Central North Sea
Onshore/Offshore	Offshore
Water Depth (ft)	130
2. GENERAL	
Reservoir Unit	Chalk Group
Hydrocarbon Type	Oil with Gas Cap
Current Production Stage	Mature Production
Current Water-cut (%)	90
Original Reservoir Temperature (°F)	163
Original Reservoir Pressure (psi)	3800
Pressure Gradient (psi/ft)	0.62
Drive Mechanism	Solution Gas, Gas Cap Expansion
3. WELL	
Total Producers	104
Total Injectors	50
Well Type	Vertical, Deviated, Extended-reach, Horizontal
Well Pattern	Staggered Line, Line Horizontal Injection and Production
Well Completion	Open-hole, Perforated Liner and Casing, Single Tubing Selective
Initial Well Rate (Vertical/Deviated Well) (BOPD)	731
Initial Well Rate (Horizontal Well) (BOPD)	2500
Well EUR (Horizontal Well) (MBO)	7404
Well Spacing (Horizontal Well) (ac)	167
4. TRAP	
Trapping Mechanism	Salt-diapir Anticline, Hydrodynamic
Depth to Top of Reservoir (ft TVDML)	5670
Trap Flank Dip (Average) (degrees)	4
Original Productive Area (ac)	10250
Original Hydrocarbon Column Height (ft)	1040

5. RESERVOIR	
Reservoir Age	Late Cretaceous to Paleocene
Depositional Environment	Pelagic, Debris-flow
Gross Reservoir Thickness (Average) (ft)	500
Net Pay (Average) (ft)	160
Lithology	Chalk
Diagenetic Reservoir Type	Type 3 Fractured Reservoir
Wettability	Water-wet
Matrix Porosity (Average) (%)	28
Air Permeability (Average) (mD)	1.75
6. FLUID	
API Gravity (Average) (°API)	30.4
Viscosity (Average) (cP)	0.58
Mobility Index (Average) (mD/cP)	3
Flowability (Average) (mD·ft/cP)	483
Initial Water Saturation (%)	30
7. RESOURCE	
Original In-Place (MMBO)	2800
Resource Density (MBO/ac)	273
EUR (MMBO)	770
Recovery to Date (% of EUR)	96
Recovery to Date (% of In-place)	26
Primary Recovery Factor (%)	6
Ultimate Recovery Factor (%)	27.5
8. IMPROVED RECOVERY	
Secondary Recovery Methods	Continuous Water Injection
Conformance Improvement Techniques	Modifying Injection Pattern
Drilling	Infill Drilling
Stimulation	Matrix Acidization, Acid Fracturing, Hydraulic Fracturing
Artificial Lift	Gas Lift
Well Treatment	Scale Removal
Incremental Recovery (Secondary Recovery) (%)	21.5

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Quantification of Resource Potential

Analogue selection is based on a broad set of parameters to establish recovery factor, resource density and well EUR trends, and to understand key controls on recovery efficiency

- Identify upside recovery potential
- Validate new opportunities for reserves growth
- Calibrate volumetric input and uncertainty
- Assess well deliverability

Analogue Search Matrix - Resource Quantification

Search Filter	Resource Quantification		Production Performance	
	Non-diagenetic	Diagenetic	Non-diagenetic	Diagenetic
Hydrocarbon Type	✓	✓	✓	✓
Onshore or Offshore	✓	✓	✓	✓
Reservoir Lithology	✓	✓	✓	✓
Depositional Environment	✓		✓	
Diagenetic Reservoir Type		✓		✓
Original In-place	✓	✓	✓	✓
Recovery to Date of EUR	✓	✓	✓	✓
API Gravity			✓	✓
Air Permeability			✓	✓
Net to Gross Ratio			✓	

Recovery to date of EUR measures analogues' maturity in terms of production - analogues with recovery to date of EUR exceeding 30% will have a more complete production history and reliable recovery factor, therefore providing reliable data for recovery factor calibration

Key Controlling Factors on Recovery Factor

Natural Drive Energy	Rock Properties	Fluid Properties	Reservoir Heterogeneity	Trap	Resource & Recovery
Drive Mechanism Pressure Depletion Index*	Matrix Porosity Bulk Porosity Air Permeability Wettability*	API Gravity Viscosity Initial Water Saturation	Net/Gross Ratio Net Pay Permeability Contrast*	Depth to Top of Reservoir Productive Area Hydrocarbon Column Height	In-place Volumes EUR Resource Density Primary RF Ultimate RF Initial Well Rate Well EUR

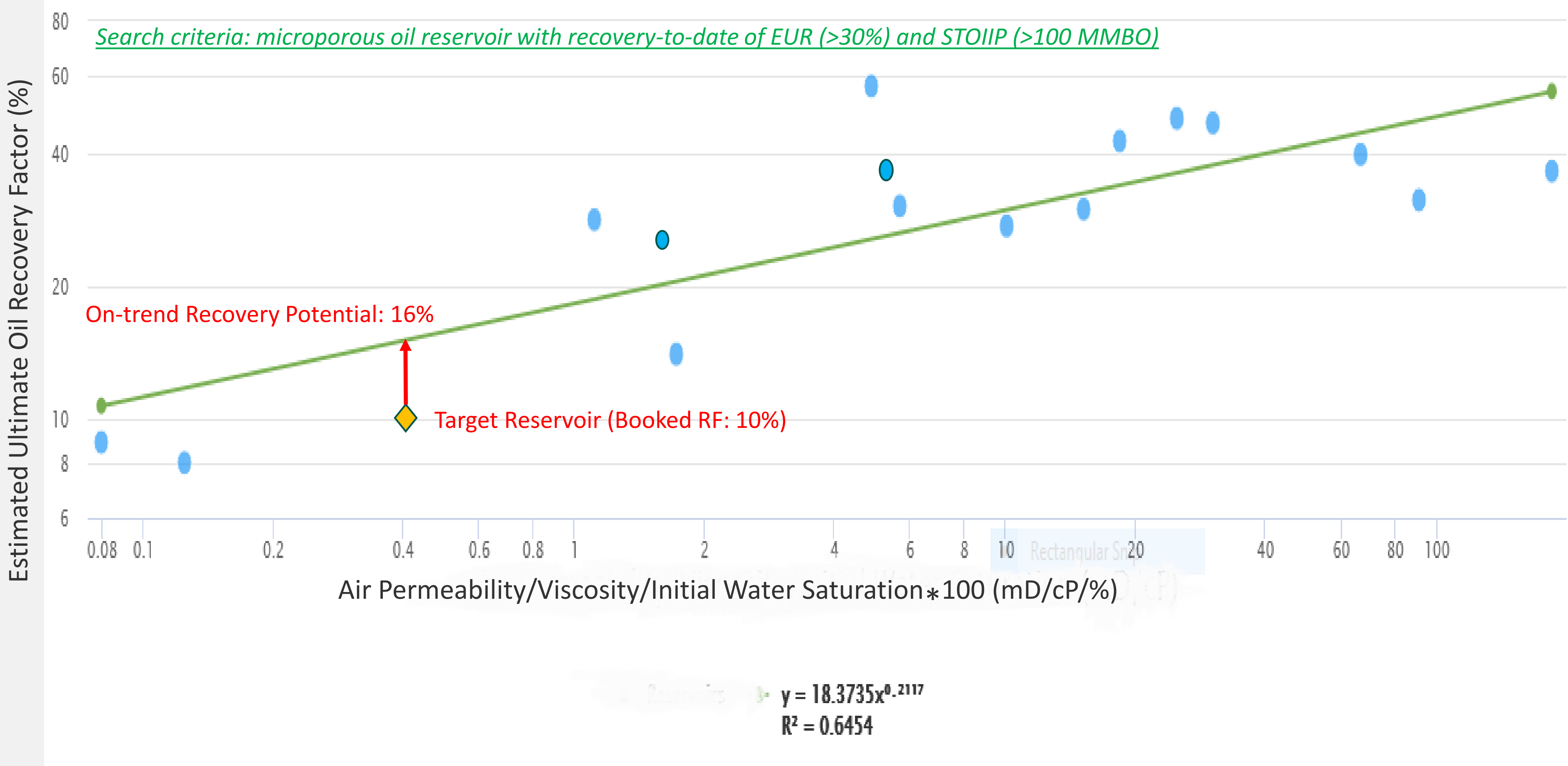
Qualified Analogues should contain all parameters highlighted in red color plus those in the analogue search matrix (22 parameters in total)

* Optional Parameters for Analysis

Case Study 1: Fractured Microporous Carbonate Oil Reservoir

- Target reservoir consists of chalky limestones characterized by microporosity and low air permeability (0.4 mD)
- Fluid-conductive faults and fractures cut through the structural crest and connected to a deep aquifer
- Initial production was under aquifer and solution-gas drive - early water breakthrough and rapid rise in water-cut caused a serious production problem
- Current development by horizontal and multilateral wells was concentrated on the field flanks where the reservoir has poorly developed fractures
- Original in-place was close to one billion barrels of oil with expected ultimate recovery factor of 10%
- After 20 years of production, recovery to date has been less than 4% of STOIIP with a current water-cut of 67%

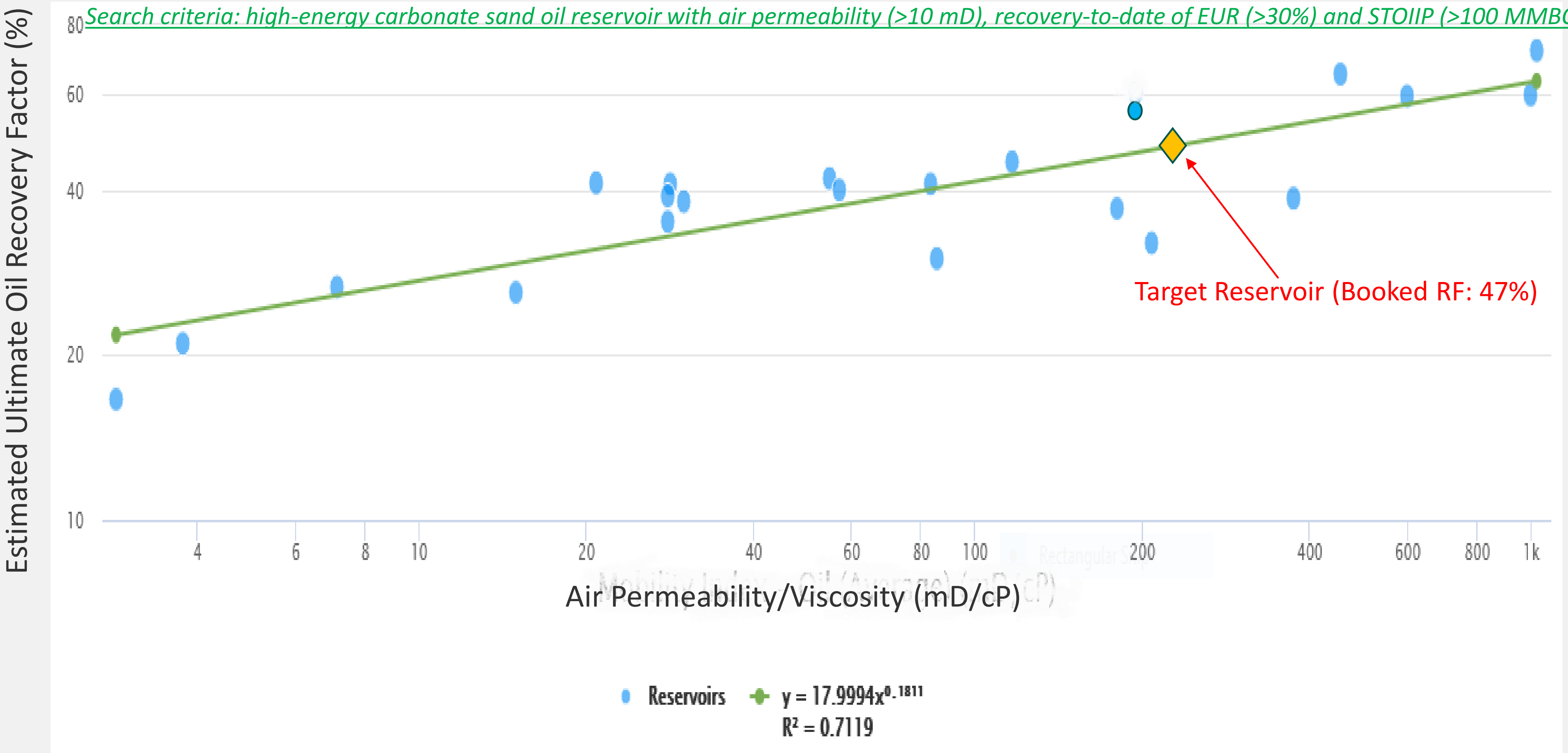
Recovery Factor Trend, Microporous Oil Reservoir



Case Study 2: High-energy Carbonate Sand Oil Reservoir

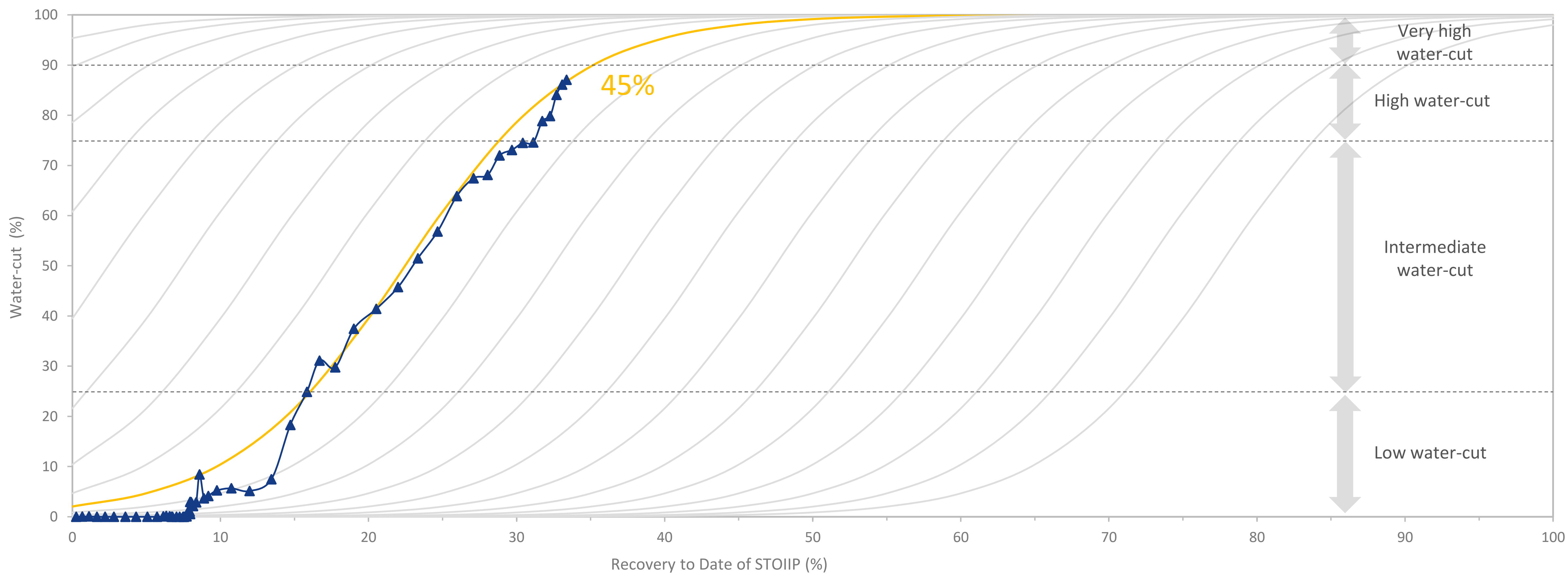
- The target reservoir consists of high-energy carbonate sands containing 32 °API oil and characterized by good matrix porosity (23%) and permeability (122 mD)
- The reservoir was initially developed with vertical wells and produced under solution gas and gas cap expansion drive
- After 26 years of production, water injection commenced, initially through vertical wells and later exclusively through horizontal producers and injectors
- Waterflood development has concentrated on better quality part of the reservoir where 31 injectors have been drilled
- Original in-place was close to 1 billion barrels of oil with an expected ultimate recovery factor of 47%

Recovery Factor Trend, Carbonate Sand Oil Reservoir



Recovery Efficiency Under Waterflood

Target reservoir currently follows 45% ultimate recovery factor trend under waterflood



Case Study 3: Offshore Turbidite Sandstone Oil Reservoir

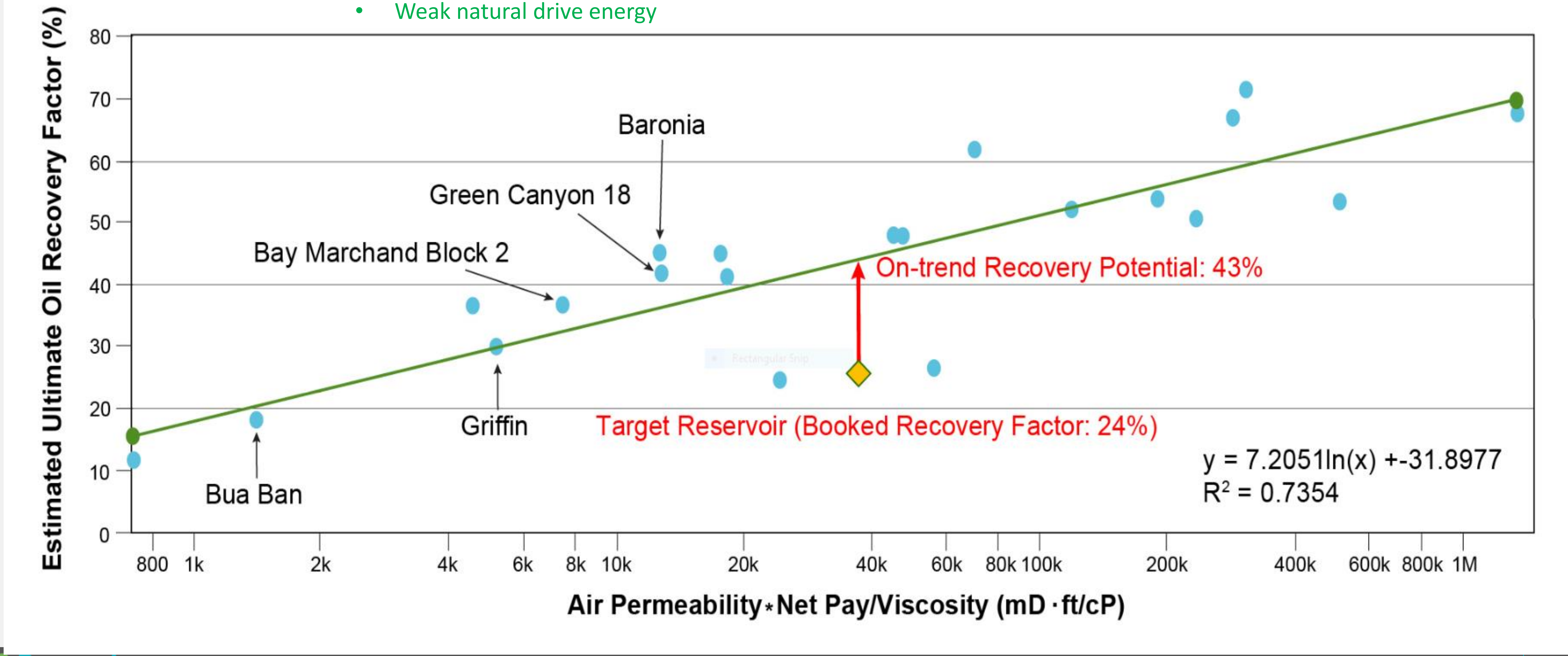
- Target reservoir consists of multi-layered turbidite sandstones characterized by thin net pay (54 ft) and low net to gross ratio (0.3)
- The reservoir has a high air permeability (455 mD) and contains 34 ºAPI gravity oil
- Initial production was under solution-gas drive
- Current development consists of 3 producers and 2 injectors with a well spacing of 333 acres
- Original in-place was 55 MMBO with an expected ultimate recovery factor of 24%
- After >six years of production, recovery-to-date has been 14.5% of STOIIP with a current water-cut of 15%

Case Study 3: Offshore Turbidite Sandstone Oil Reservoir

Search criteria: offshore sandstone oil reservoir with recovery-to-date of EUR (>30%) and STOIIP (<100 MMBO)

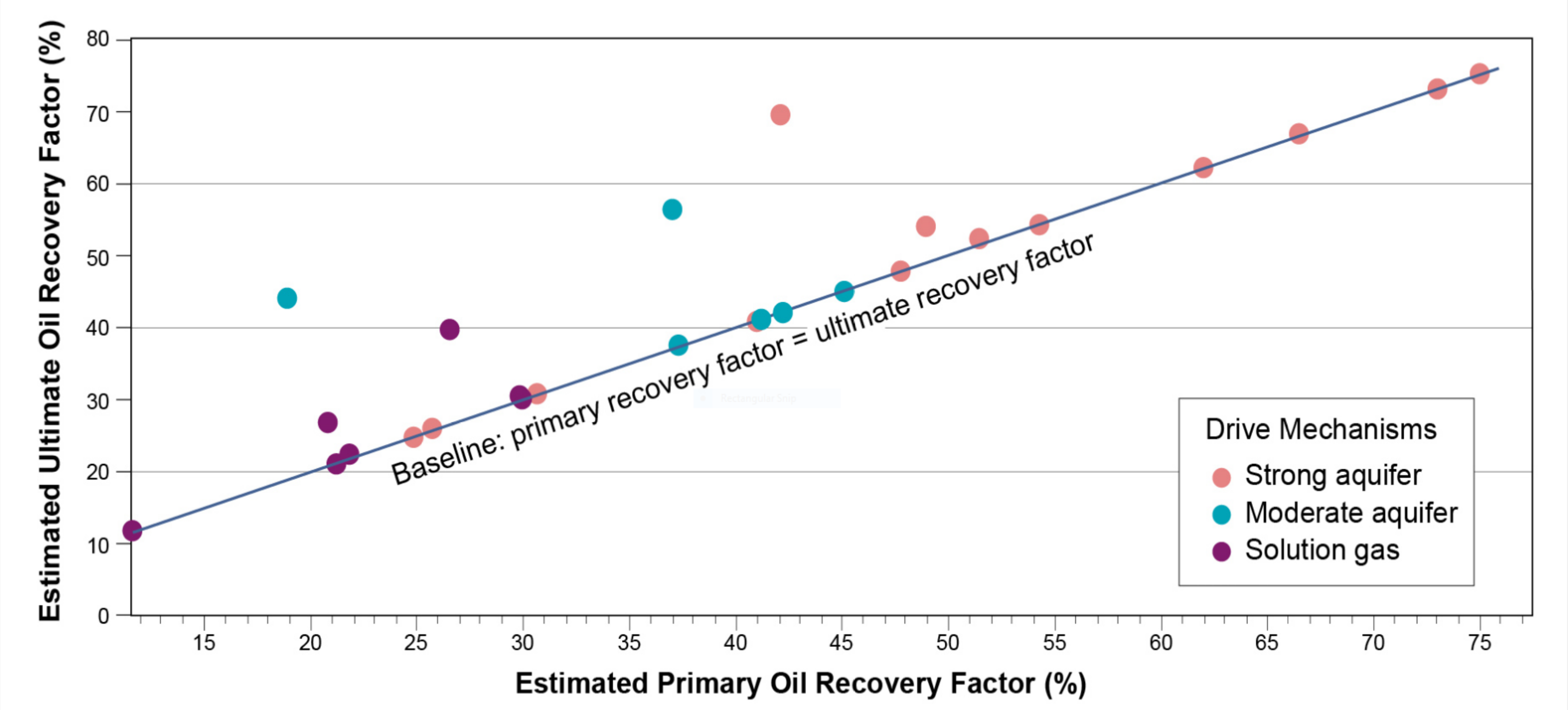
Specific Critical Issues

- Thin net pay (<60 ft)
- Low net to gross ratio (<0.3)
- Weak natural drive energy



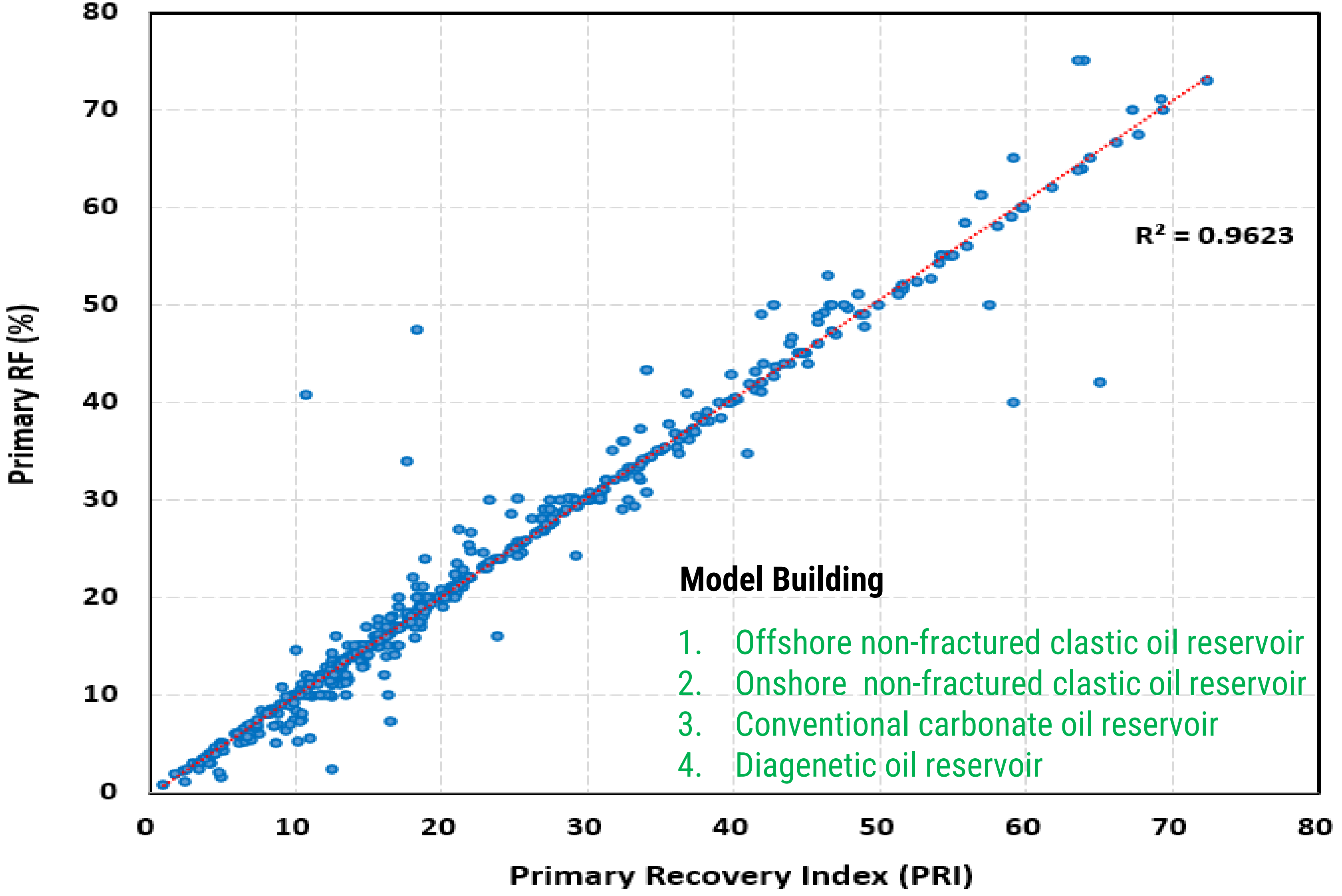
Impact of Natural Drive Mechanism on Recovery Factor

Offshore sandstone oil reservoir with recovery-to-date of EUR (>30%) and STOIIP <200 MMBO



Primary Recovery Index (PRI): A Proxy for Primary Recovery Factor

Machine Learning Application using 17 intrinsic parameters



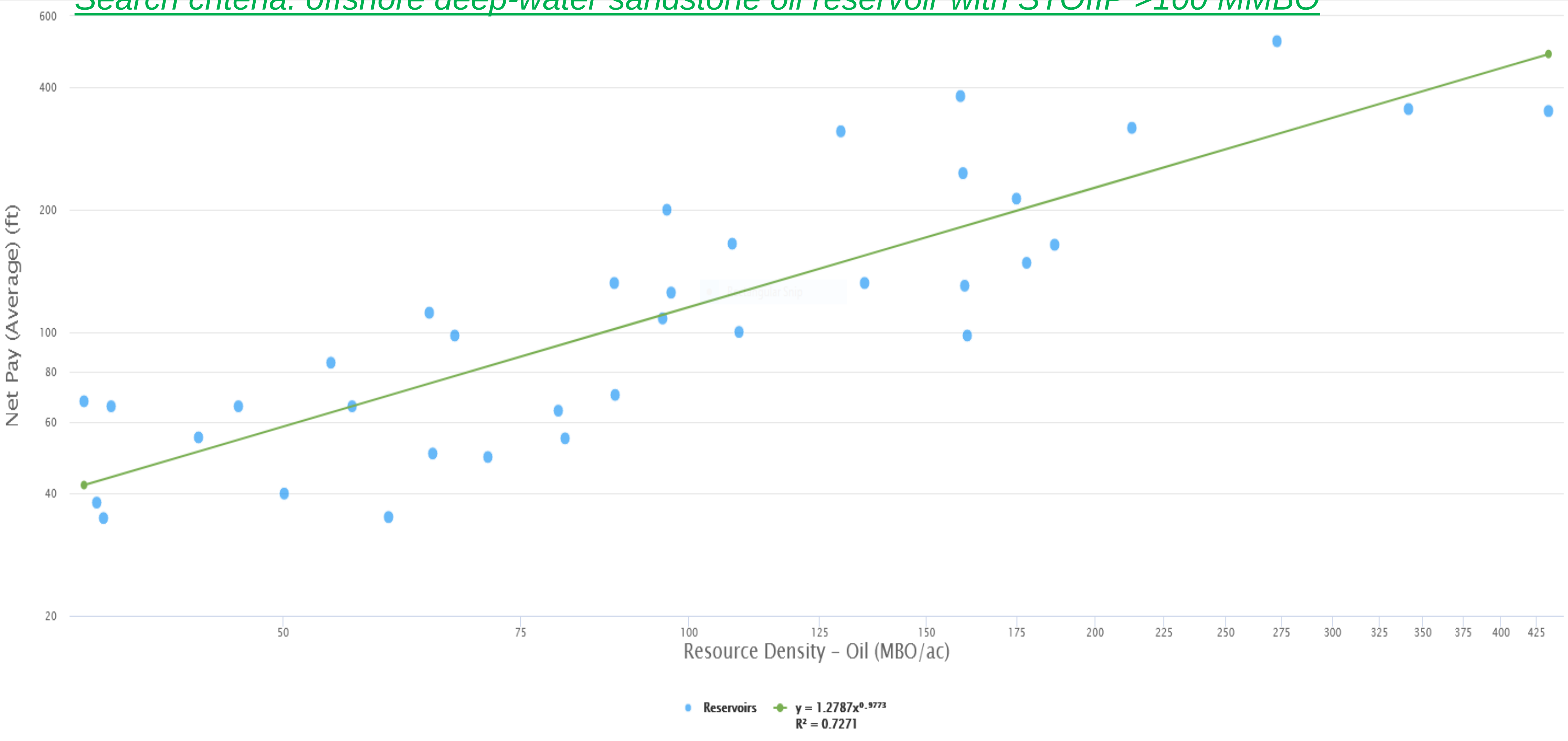
Key Parameters

- Pressure depletion index
- Pressure gradient
- Depth to top of reservoir
- Structural compartment count
- Trap flank dip
- Original oil column height
- Reservoir flow unit count
- Net pay
- Matrix porosity
- Bulk porosity
- Air permeability
- Viscosity
- Bubble point pressure
- Pour point temperature
- Original oil saturation
- Original water saturation
- Resource density

Pressure depletion index: normalized score of natural drive types

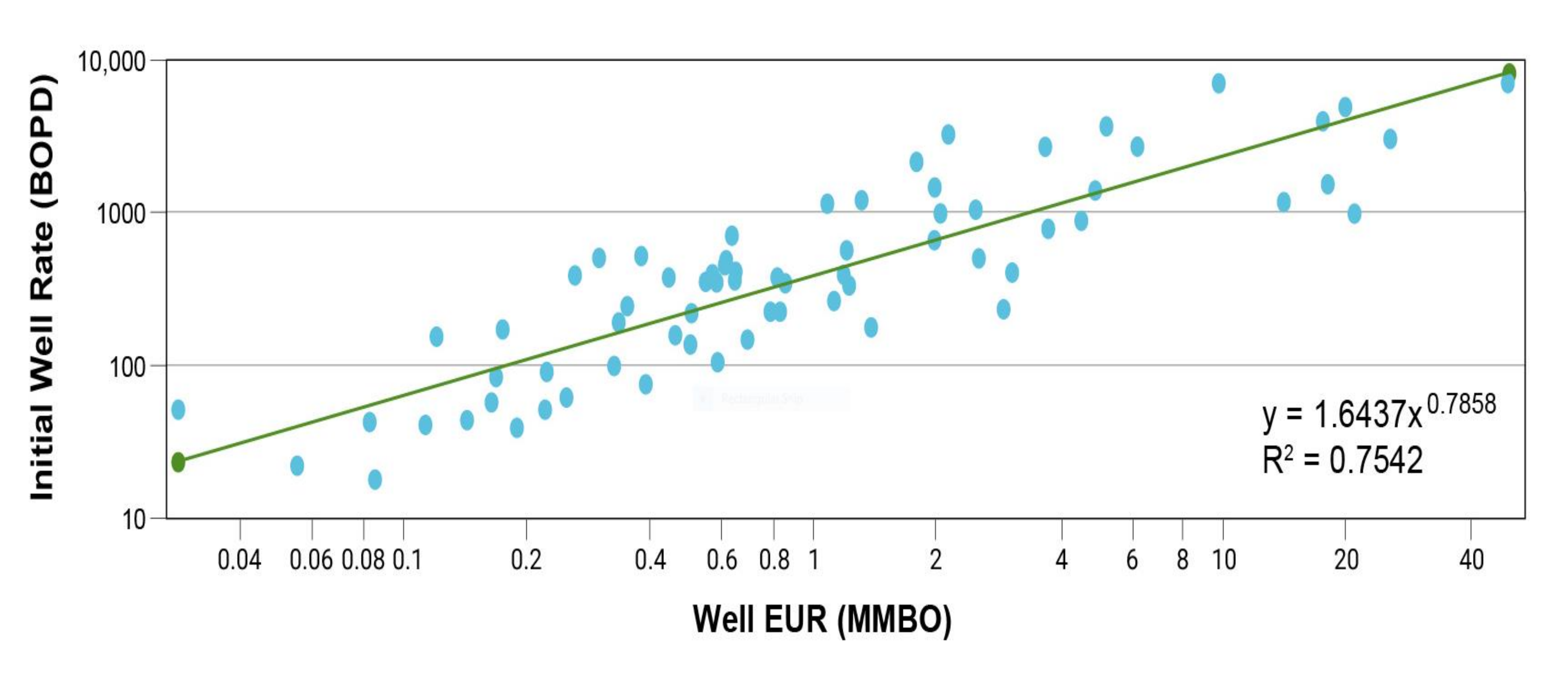
Calibrate Volumetric Uncertainty

Search criteria: offshore deep-water sandstone oil reservoir with STOIIP >100 MMBO



Assess Well Deliverability

Search criteria: onshore clastic oil reservoir with STOIIP >500 MMBO



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5. Identification of Best Practices & Lessons Learned	Isolate specific critical issues and focus on a smaller number of applicable analogues to identify both best practices & lessons learned

Assessment of Production Performance

Analogue selection is based on a narrowly defined set of parameters relevant to the characterization and assessment of production performance

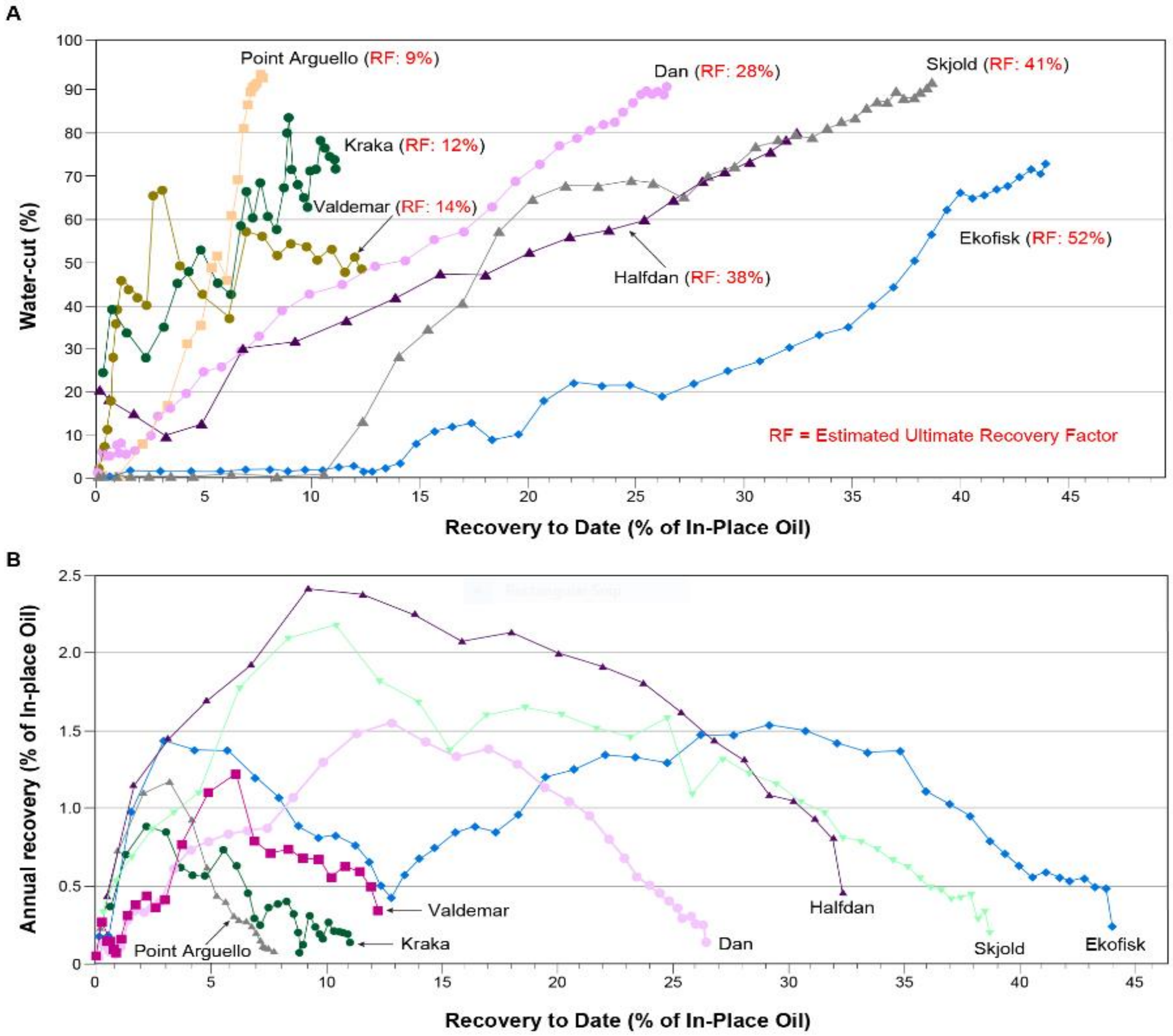
- Analyze production characteristics
- Evaluate impact of water-cut on production behavior
- Determine well spacing, number of producers and annual plateau recovery of STOIIP required to achieve the upside recovery potential
- Validate production profile derived from classical reservoir engineering methods or simulation models

Analogue Search Matrix - Production Performance

Search Filter	Resource Quantification		Production Performance	
	Non-diagenetic	Diagenetic	Non-diagenetic	Diagenetic
Hydrocarbon Type	✓	✓	✓	✓
Onshore or Offshore	✓	✓	✓	✓
Reservoir Lithology	✓	✓	✓	✓
Depositional Environment	✓		✓	
Diagenetic Reservoir Type		✓		✓
Original In-place	✓	✓	✓	✓
Recovery to Date of EUR	✓	✓	✓	✓
API Gravity			✓	✓
Air Permeability			✓	✓
Net to Gross Ratio			✓	

Recovery to date of EUR measures analogues' maturity in terms of production - analogues with recovery to date of EUR exceeding 30% will have a more complete production history and reliable recovery factor, therefore providing reliable data for recovery factor calibration

Production Characteristics, Offshore Microporous Oil Reservoirs



Search Criteria

- *Hydrocarbon Type: Oil*
- *Development Situation: Offshore*
- *Diagenetic Reservoir Type: Type 3 fractured Reservoir*
- *Recovery to date of EUR: >30%*
- *STOIIP: >300 MMBO*

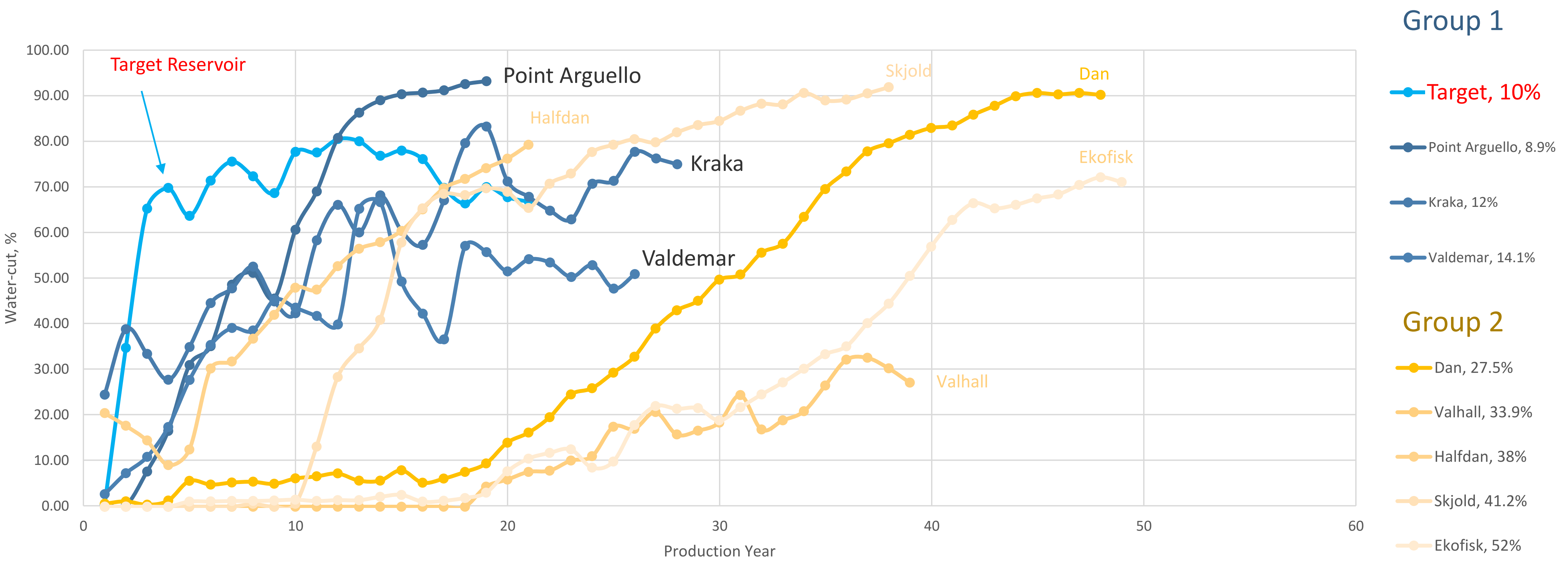
Production Characteristics, Offshore Fractured Microporous oil Reservoirs

Numerical Parameter	No. of Analogues	P90-P10 Range of Analogues		
		P90	P50	P10
Buildup duration (months)	13	5	55	201
Plateau duration (months)	13	12	24	67
Plateau annual recovery (% of in-place oil)	13	1	1.4	4
Plateau annual recovery (% of EUR oil)	13	3	7	15
Horizontal well initial rate (BOPD)	8	2000	4550	5000
Horizontal well EUR (MMBO)	4	4	6	10
Vertical/deviated well spacing (ac)	7	27	88	241
Horizontal well spacing (ac)	7	38	167	312
Horizontal well distance between producers (ft)	7	637	1200	1640

Water-cut Performance, Offshore Fractured Microporous Oil Reservoirs

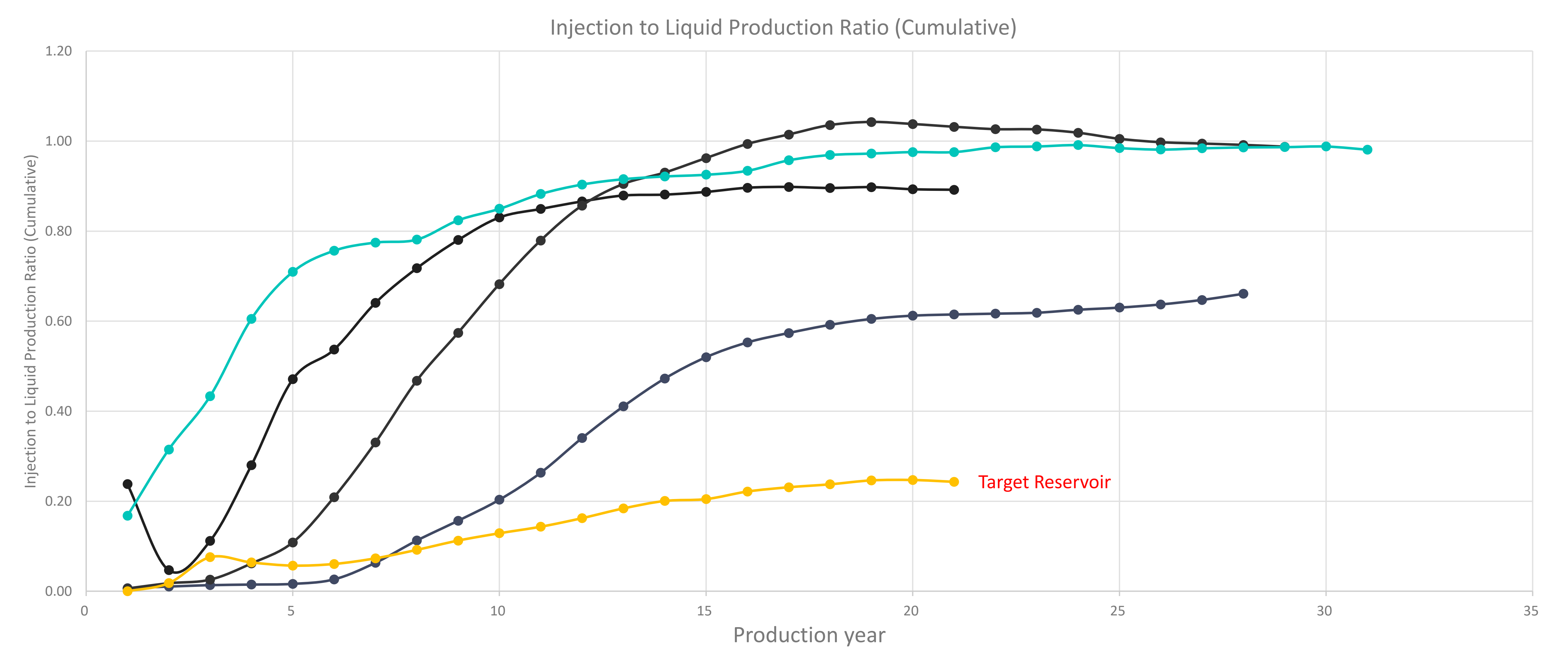
Two trends of water-cut performance:

- Group 1: Rapid production increase during ramp-up period, followed by early water breakthrough
- Group 2: Gradual production rise during ramp-up period, followed by late water breakthrough
- Group 2 analogues have more effective water control and higher ultimate recovery factors



Voidage Replacement Ratio (VRR), Offshore Fractured Microporous Oil Reservoirs

Target reservoir has a low voidage replacement ratio (VRR) compared with offshore analogues



DAKS Analogue Benchmarking Workflow

1. Definition of Problems and Objectives

Define the specific problems to address and the critical questions to be answered

2. Parameterization of the Target Reservoir

Catalogue prospects and assets using consistent standards and a holistic classification scheme

3. Quantification of Resource Potential

Establish recovery factor trends using key intrinsic parameters that have major impact on recovery efficiency

4. Assessment of Production Performance

Analyze normalized production and injection performance data from applicable analogues

5. Identification of Best Practices & Lessons Learned

Isolate specific critical issues and focus on a smaller number of applicable analogues to identify both best practices & lessons learned

Identification of Best Practices and Lessons Learned

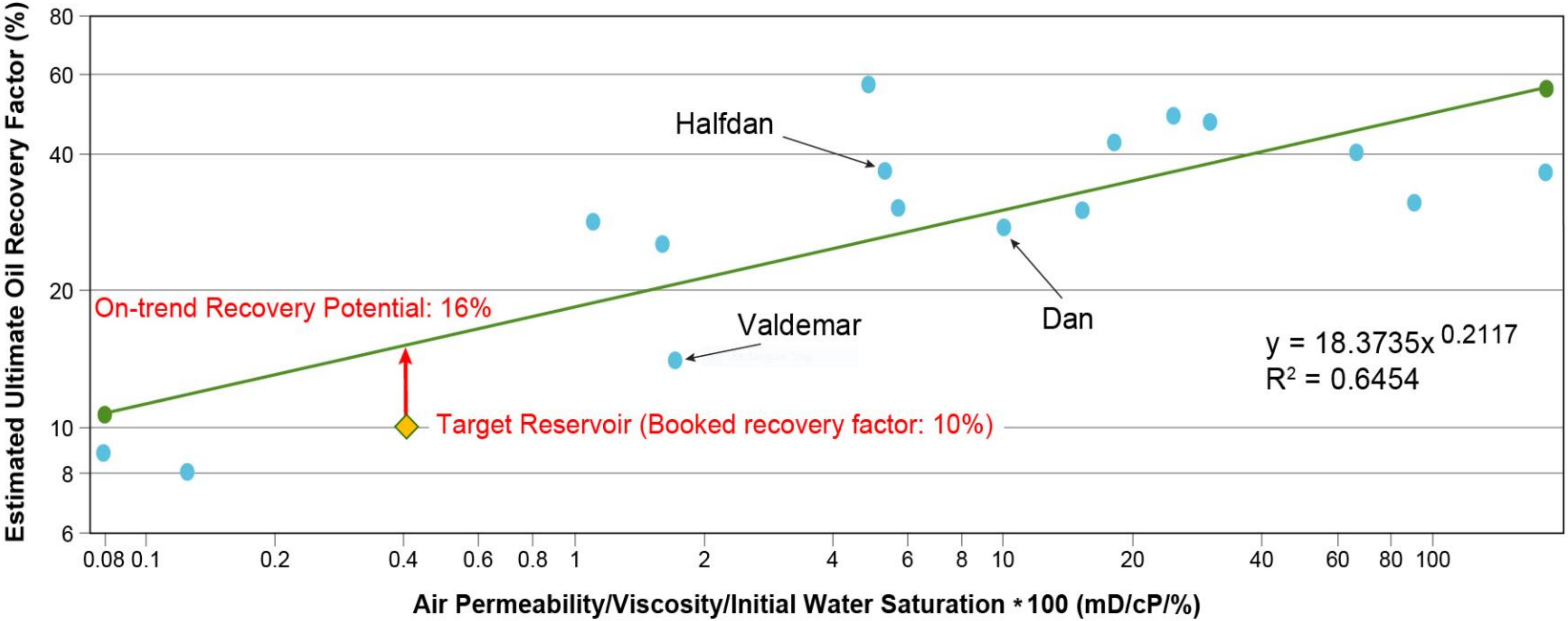
Isolate specific critical issues and focus on a smaller number of analogues that more closely match the target reservoir with the aim to identify both best practices and lessons learned

- Identify mitigation measures to optimize production and recovery - e.g., well type, pattern and completion, well placement, drawdown, infill well, pressure maintenance and conformance improvement techniques
- Assess effectiveness of achieving incremental recovery by infill drilling, secondary recovery and EOR methods
- Evaluate impact of well-scale improved recovery methods on production performance - e.g., drilling, stimulation, artificial lift, sand control, well productivity optimization, treatment and workover

Case Study 1: Fractured Microporous Carbonate Oil Reservoir

Specific Critical Issues

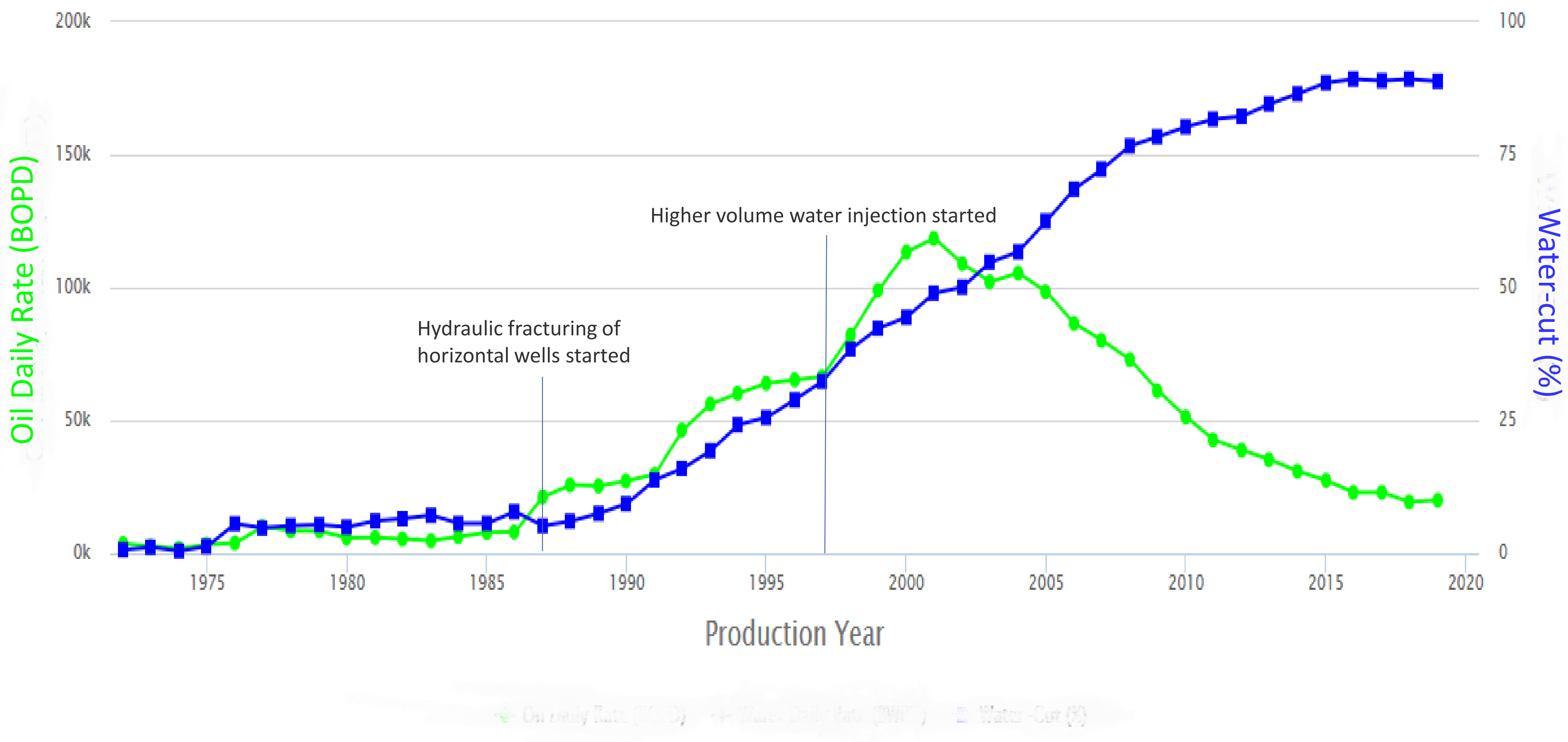
- Connected to a deep aquifer via central graben faults
- Poorly fractured on field flanks
- Low matrix permeability (0.4 mD)



Poorly Fractured Chalk, Dan Field, Offshore Denmark

- Production from a water-wet chalk reservoir with matrix porosity of 28%, air permeability of 1.75 mD and poorly developed natural fractures
- The field has a STOIIP of 2,800 MMBO and came onstream in 1972 under solution-gas and gas-cap expansion drive - hydraulic fracturing and matrix acidization was required from start-up to provide economic flow rates
- Production through vertical or deviated wells stimulated with acid or sand-propped fractures was <10,000 BOPD between 1972 and 1987
- Drilling of long horizontal wells, multi-zonal hydraulic fracturing and high-rate seawater injection caused a marked increase in production which reached a peak of 118,536 BOPD in 2000
- Selective completions were used to isolate individual fractures and control the injection
- Successful implementation of advanced drilling and completion technologies and effective water injection led to an estimated ultimate RF of 28%

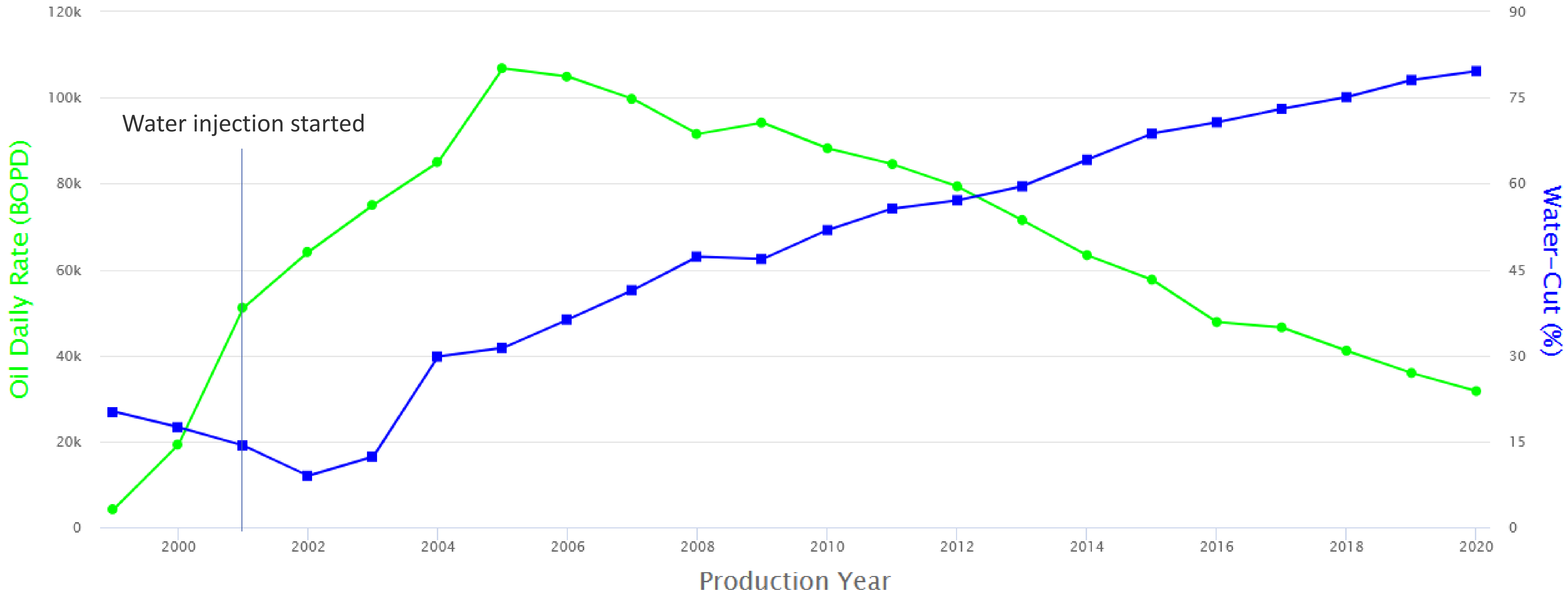
Production History of Dan Field, Offshore Denmark



Low Permeability Chalk, Halfdan Field, Offshore Denmark

- Production from a water-wet chalk reservoir with matrix porosity of 28%, air permeability of 1.5 mD and well-developed fractures in its structural crest
- The field has a STOIIP of 1,615 MMBO and came onstream in 2000 under solution-gas drive supplemented by water injection
- The field was developed using long horizontal wells arranged in a parallel pattern of alternating producers and water injectors
- Fractures were induced by multiple acid fracturing in producers and by high-rate water injection in injectors
- Selective completions provide control of individual production and injection zones
- Production peaked at 106,846 BOPD in 2005 before falling steadily
- Successful implementation of high-rate water injection, drilling of long horizontal wells and acid stimulation led to an estimated ultimate RF of 38%

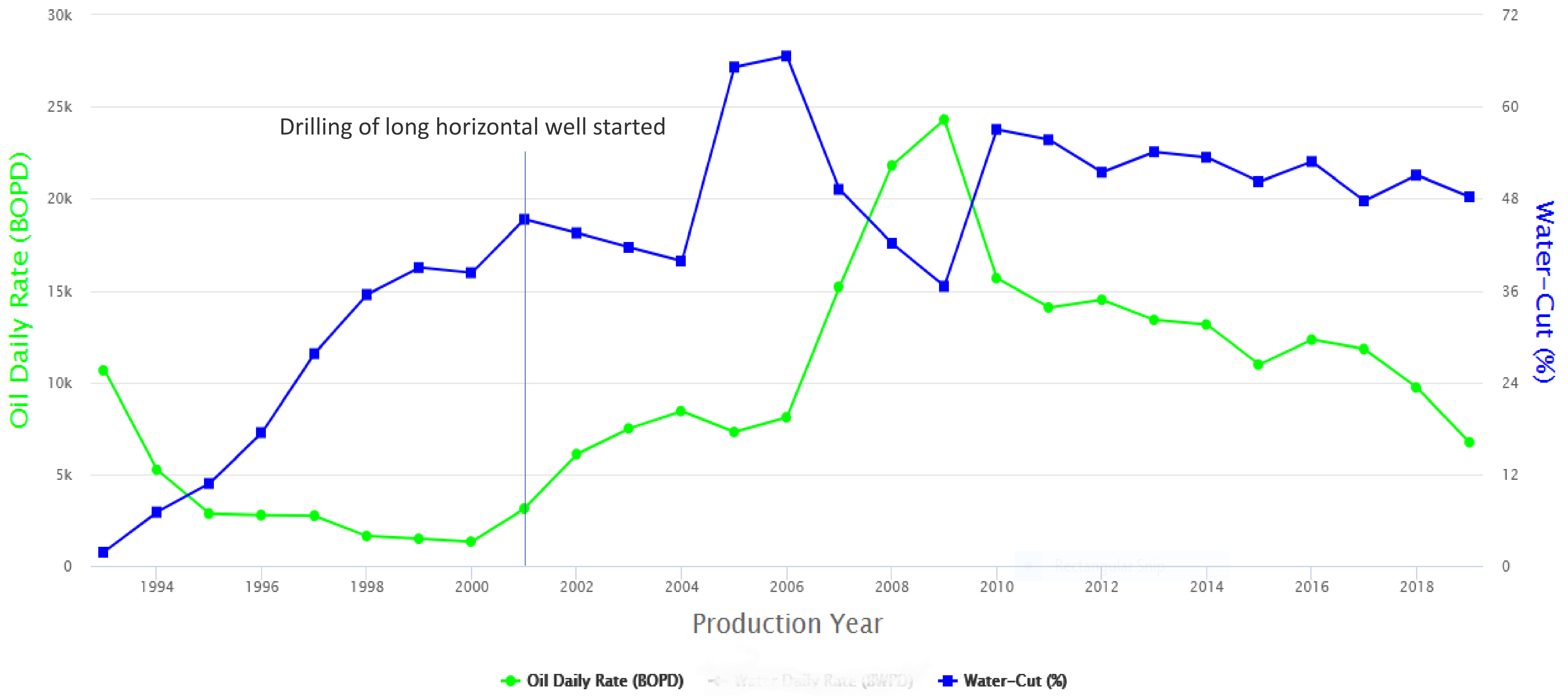
Production History of Halfdan Field, Offshore Denmark



Low Permeability Chalk, Valdemar Field, Offshore Denmark

- Production from a mixed-wettability chalk reservoir with matrix porosity of 25%, air permeability of 0.4 mD and STOIIP of 725 MMBO
- The structure is heavily faulted with numerous isolated compartments connected to a deep aquifer
- The field came onstream in 1993 under aquifer and solution-gas drive - water was produced from the start-up
- Initial production through conventional horizontal wells was relatively low, but drilling of long horizontal wells caused a marked increase in production which reached a peak of 24,298 BOPD in 2009
- Owing to low permeability, wells have been hydraulically fractured
- Poor control of water production and lack of effective secondary recovery program led to an estimated ultimate RF of only 14%
- Recent numerical modelling indicated an incremental recovery of 11.5% by lean gas injection

Production History of Valdemar Field, Offshore Denmark



C&C Reservoirs

Well Design, Offshore Fractured Microporous Oil Reservoirs

Well Design	No. of Analogues	Primary	Secondary	Tertiary
Well type	13	Horizontal well	Vertical or deviated well	Multilateral and extended-reach well
Well pattern	12	Line horizontal injection and production	Radial horizontal	Irregular
Completion	13	Perforated casing	Perforated liner	Single tubing selective
Perforation	5	Coiled tubing-conveyed	Wireline-conveyed	Tubing-conveyed

IR Methods, Offshore Fractured Microporous Oil Reservoirs

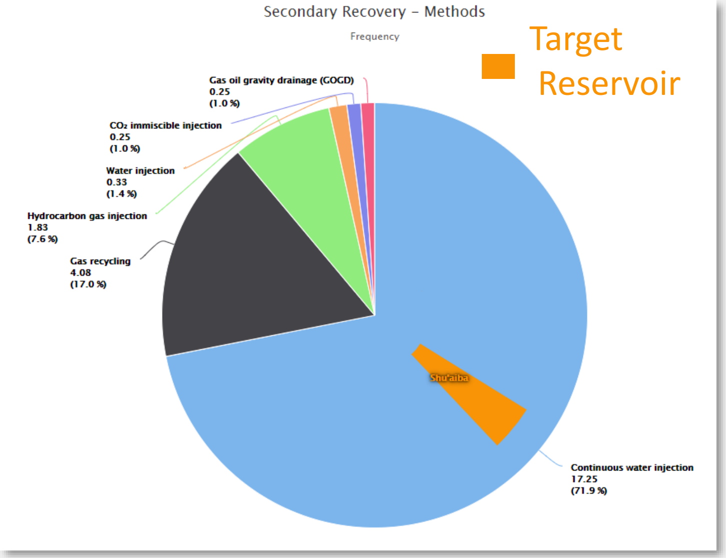
Improved Recovery Methods	No of Analogues	Primary	Secondary	Tertiary
Secondary recovery method	9	Water injection	Gas injection	-
Conformance improvement	7	Selective injection	Water plugging	Modifying injection pattern
Drilling	12	Sidetracking	Infill drilling	Step-out drilling
Stimulation	12	Matrix acidization	Acid fracturing	Hydraulic fracturing
Artificial lift	10	Gas lift	Electric submersible pump	-
Well treatment	5	Wax removal	Scale inhibitor treatment	Scale removal
Workover	5	Selective perforation	Recompletion	-

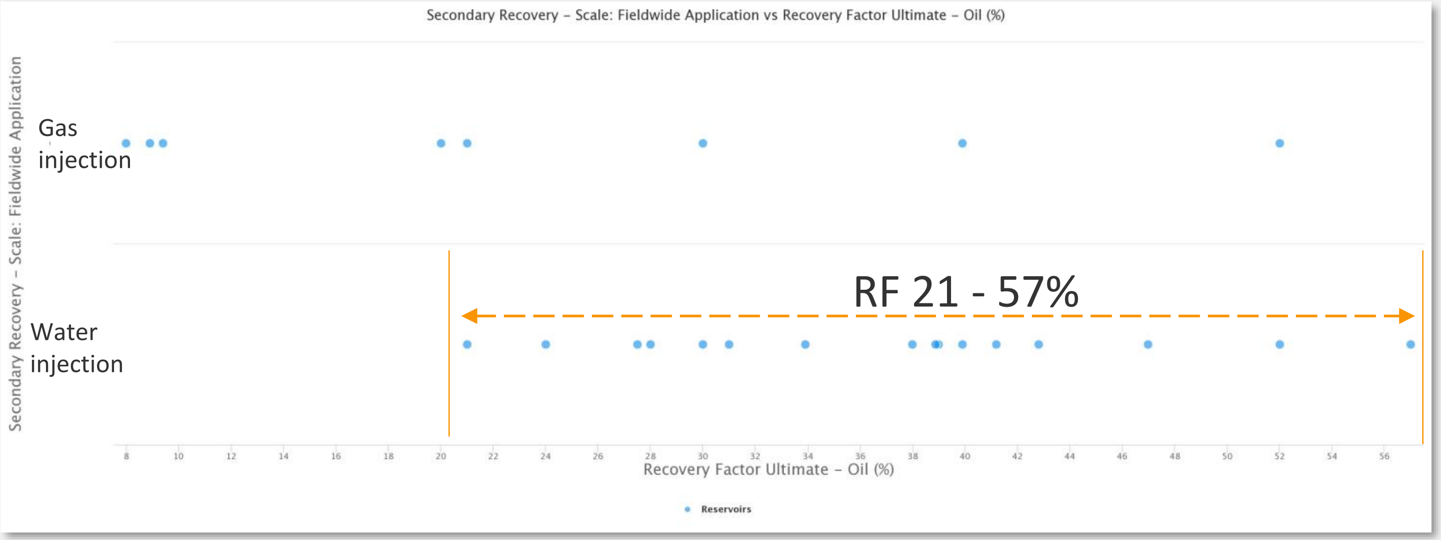
Secondary Recovery Methods, Fractured Microporous Oil Reservoirs

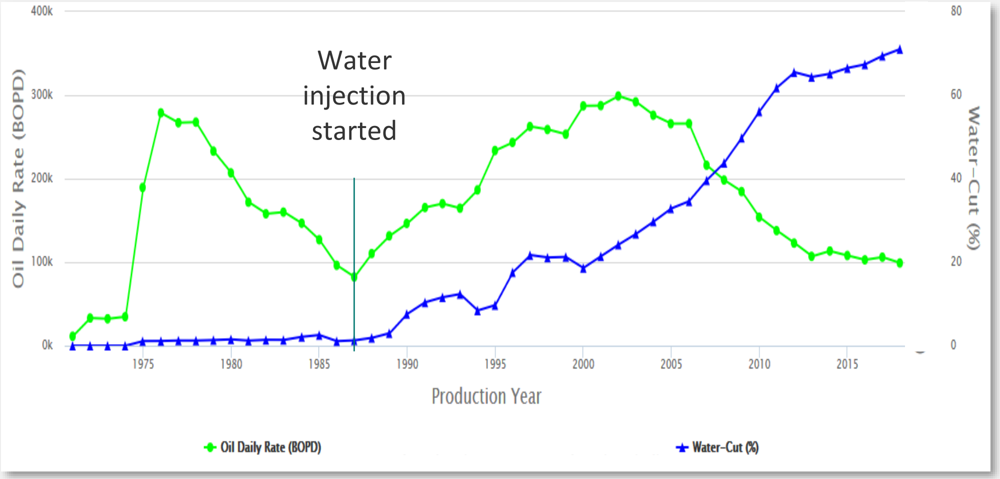
A range of secondary techniques have been used by analogues - the most common technique is continuous water injection

- Water injection has proven to be the most effective technique in increasing Ultimate Recovery Factor

- Successful implementation of water injection at the Ekofisk Field has led to an increased incremental oil recovery of 28% of STOIIP and an estimated Ultimate Recovery Factor of 52%

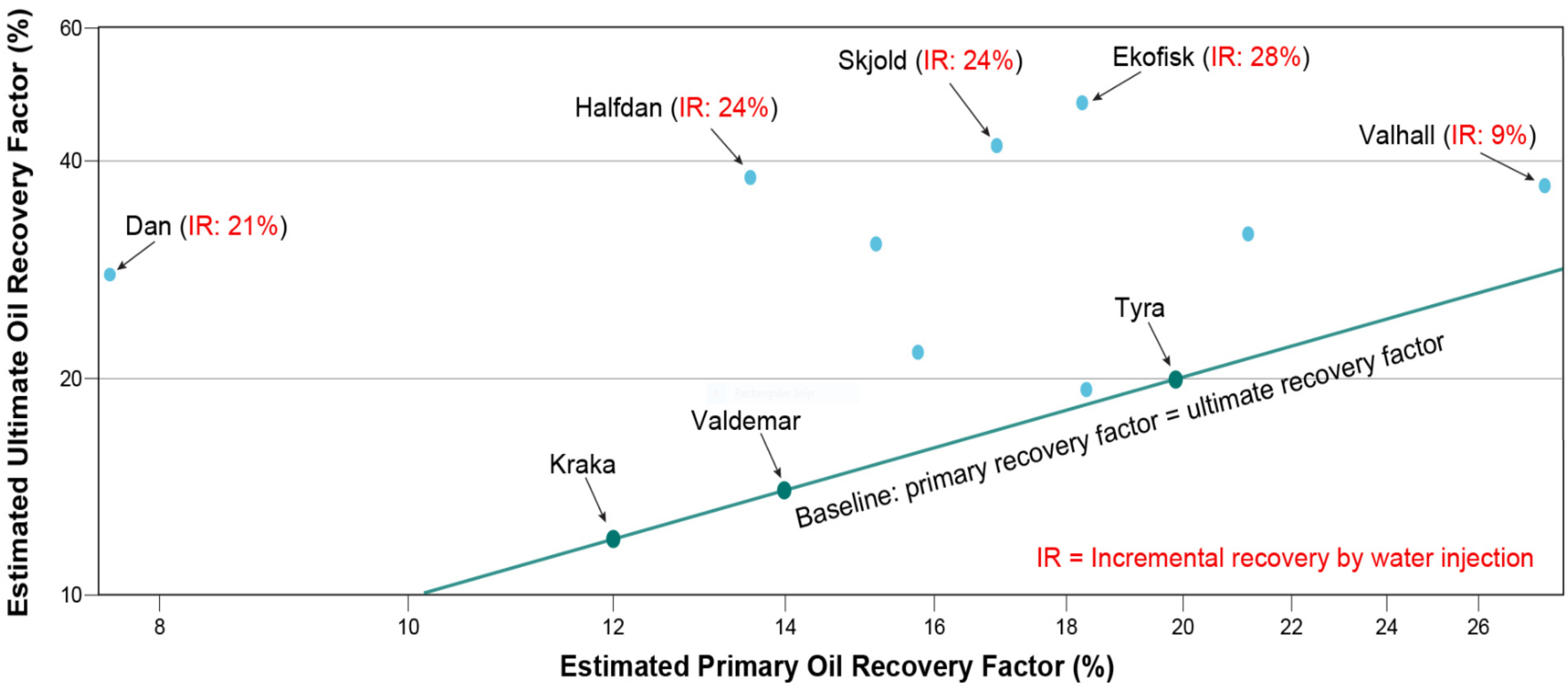






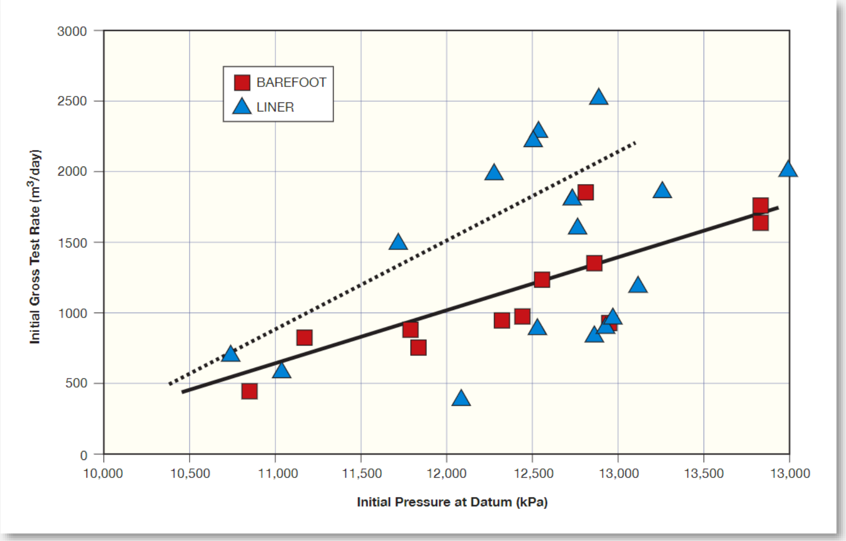
Production history – Ekofisk Field

Incremental Recovery, Offshore Fractured Microporous Oil Reservoirs

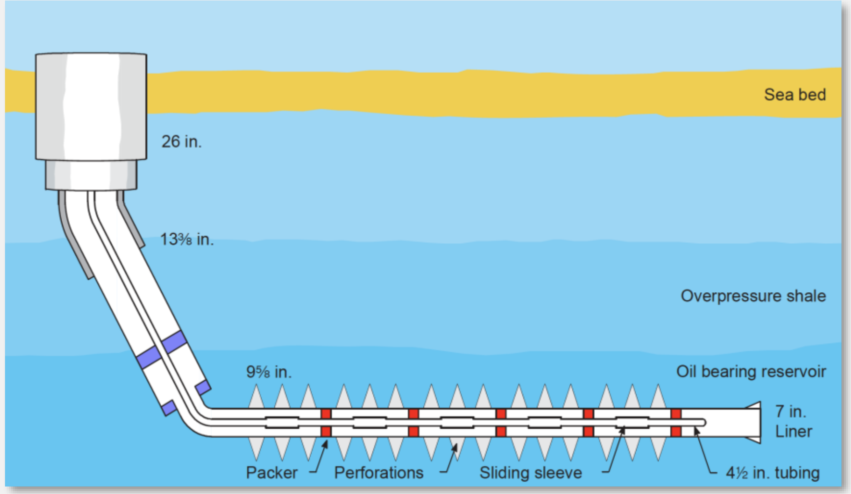


Selective Completion to Optimize Production

- At Yibal Field, onshore Oman, early wells had open-hole completions
- Early water breakthrough led to introduction of selective completions to isolate potential water-bearing fractures
- Higher flow rates have been achieved from wells with perforated liners than from wells with open-hole completions
- This has been achieved by well interventions, including stimulations, additional perforation and isolation of watered out zones after completion



- At Dan Field, offshore Denmark, the reservoir is stimulated by acid fracturing with sand proppant to keep fractures open
- A typical horizontal production well has ~15 sand-propped fractures
- Cemented liners and selective completions are installed to allow control of the stimulation and production from each fracture



Intelligent Completion to Optimize Production

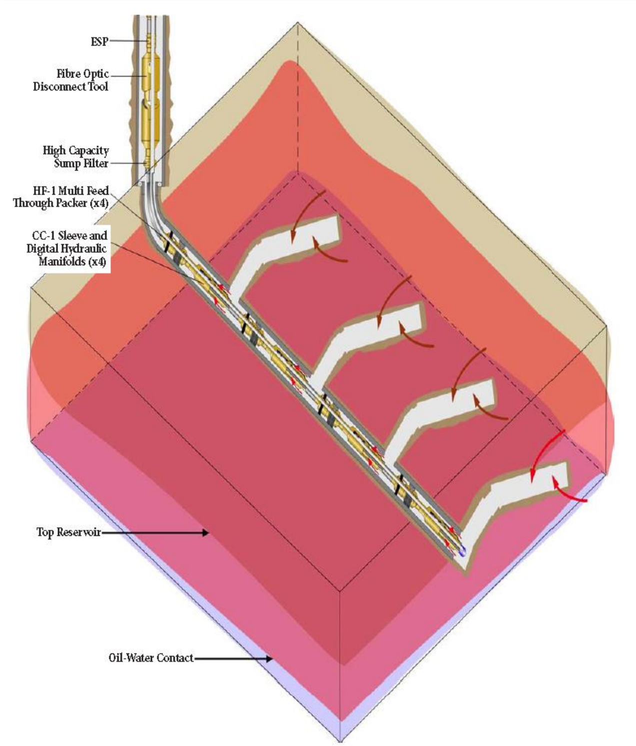
Saih Rawl – Shuaiba, Oman : Intelligent Well Completion Producer

Onshore/Offshore	Drive Mechanisms	Wettability	Secondary Recovery - Scale: Fieldwide Application	Recovery Factor Ultimate
Onshore	Unknown	Unknown	Continuous water injection	42.8

- A ‘Smart Well’ system has been effective in improving water-injection efficiency and reducing water-cuts

- This consists of remotely-operated downhole interval control valves that allow each of four laterals legs to be independently opened and closed using three hydraulic lines to surface. Using this technology, laterals with high water-cut were selectively closed off

- Initial results indicated a reduction in water production by 28%, while net oil production increased by 1437 BOPD. The well performed beyond expectations with an incremental 1200 BOPD six months after the installation. Estimated incremental production for the well is >3.5 MMBO



Selective Injection, Offshore Fractured Microporous Oil Reservoirs

Successful application of selective injection is dependent on understanding displacement efficiency and fracture distribution

- The main purpose of implementing selective injection is to improve efficiency of waterflood schemes
- Selective injection is defined as individual water injectors are shut-in, or their injection rates are increased or reduced, in order to target the water flood to particular areas.
- Selective injection has been applied at both the Skjold Field and Machar Field

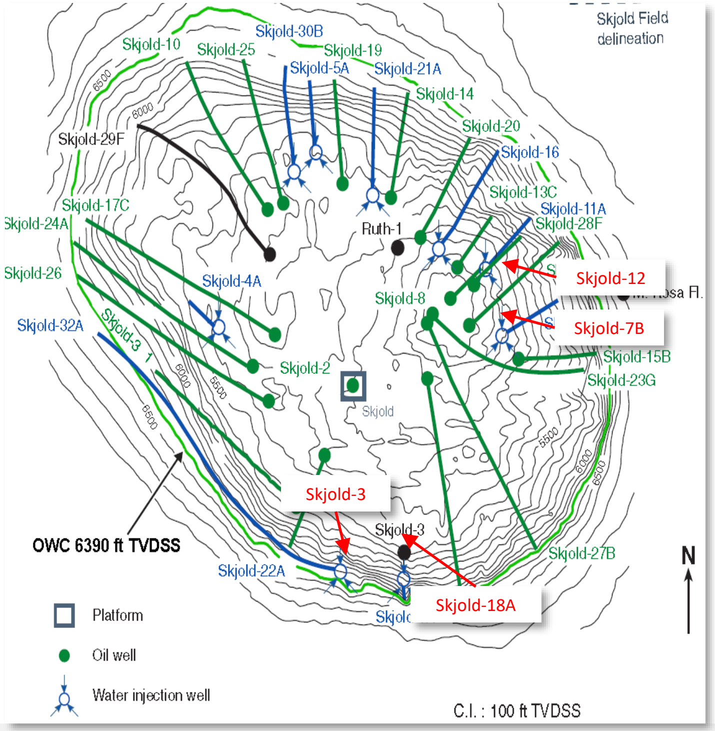
	Target Reservoir	Machar	Skjold
Lithology	Chalky Limestone	Chalk	Chalk
Ultimate RF (%)	14	22	41
Air Permeability (mD)	1	0.22	1
Matrix Porosity (%)	21	22	23

Selective Injection Best Practice, Skjold Field, Offshore Denmark

Skjold – Chalk Group, Denmark

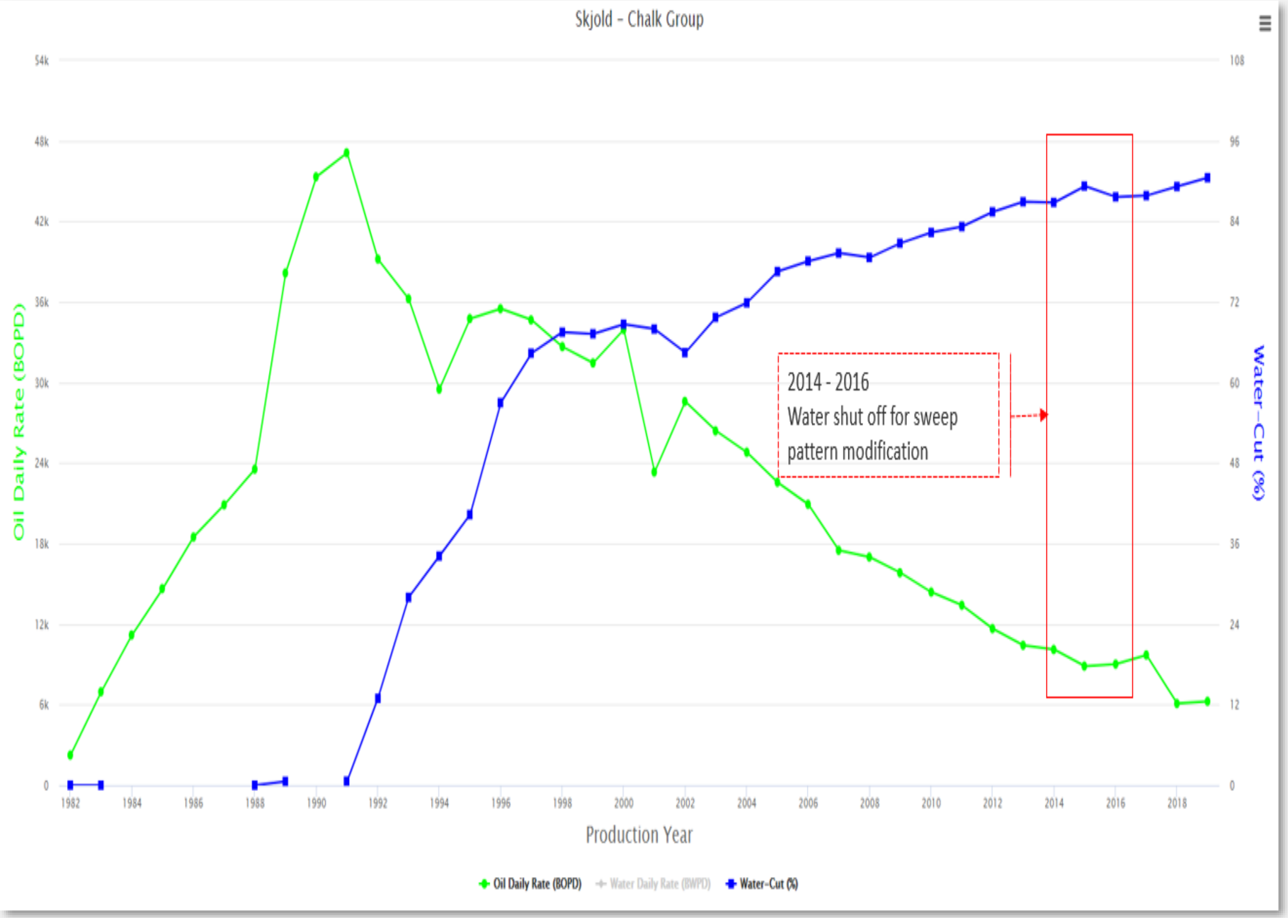
Onshore/Offshore	Drive Mechanisms	Wettability	Secondary Recovery - Scale: Fieldwide Application	Recovery Factor Ultimate
Offshore	Capillary imbibition	Water-wet	Continuous water injection	41.2

- Water injection into fractured reservoir was highly effective as water was readily imbibed into the chalk matrix, allowing oil to be displaced by capillary imbibition recovery
- All injectors except one are completed in the water leg close to the matrix OWC, but owing to fractured nature of the reservoir, water breakthrough times can be short. A breakthrough time of 20 hours occurred between injector Skjold-7 and producer Skjold-12; the latter located ~250 m away in a more fractured part of the field
- Wells located in a more matrix-dominated part of the field have longer water-free production period - e.g., injector Skjold-3 and producer Skjold-18



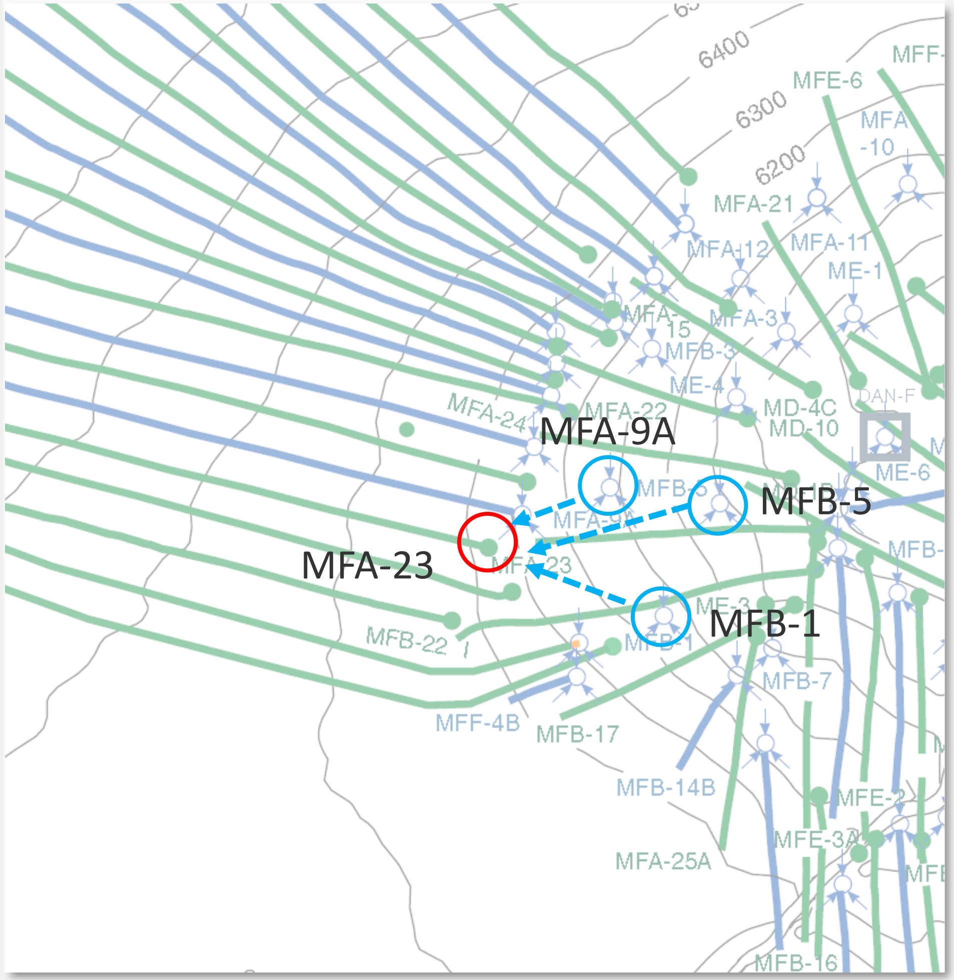
Modifying Injection Pattern Best Practice, Skjold Field, Offshore Denmark

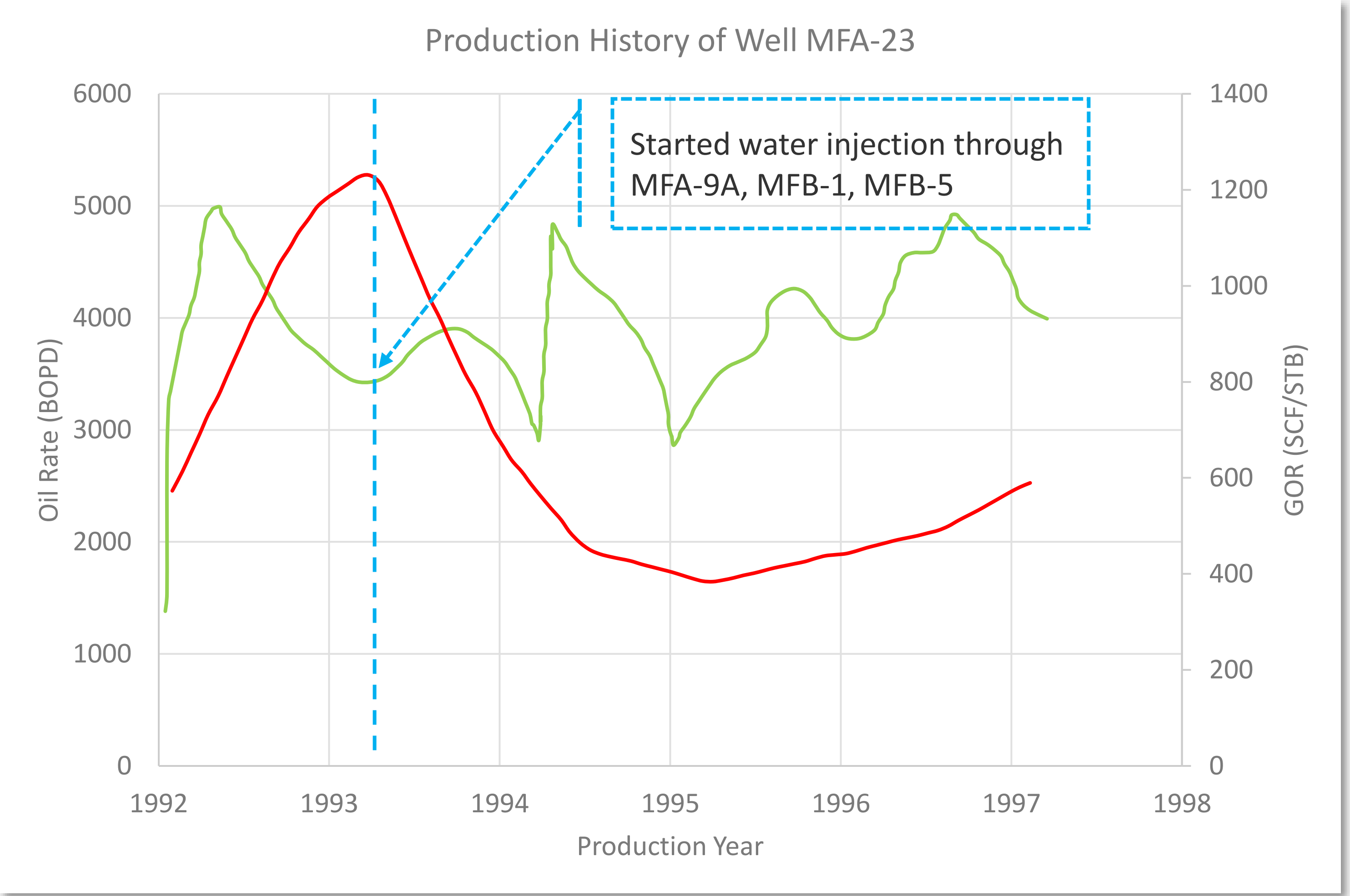
- Producer shut-in is required since high water-cut wells increase the producing pressure
- This strategy also reduces water cycling and improves pressure maintenance
- Some injectors are also shut in or injection rates reduced where they are responsible for water cycling, enabling pressure and flow reduction through fractured reservoir zones, leading to increased flow in less fractured areas
- A trial in 2016, which comprised the shutting-in of one injector and one producer and reducing injection in several other wells, resulted in a 20% increase in field production with no detrimental impact on voidage balance



Modifying Injection Pattern Best Practice, Dan Field, Offshore Denmark

At the Dan Field, producers MFA-9A, MFB-1, MFB-5 were converted to high-rate water injector above the fracture-propagation pressure (FPP) to support production from well MFA-23

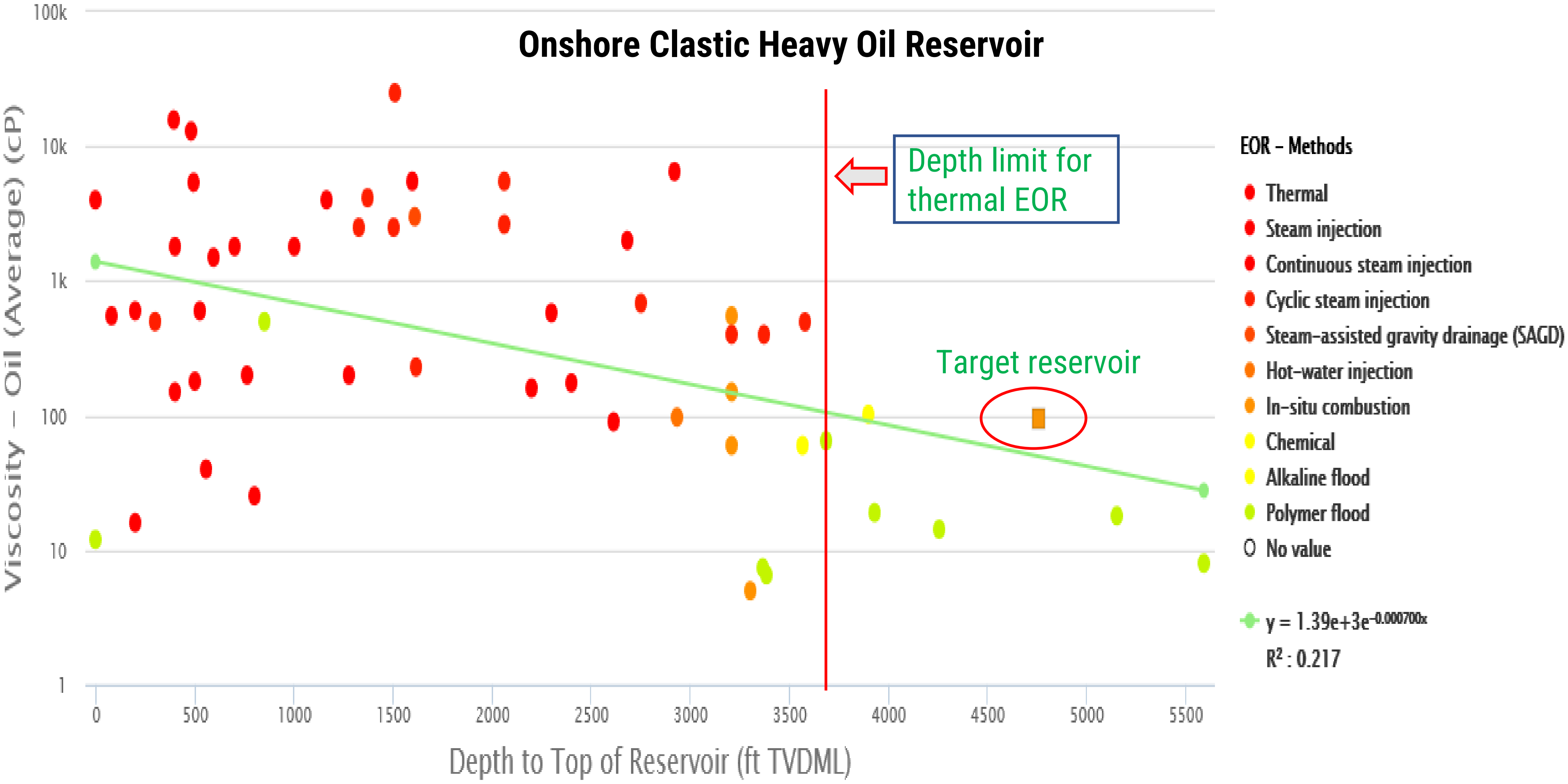




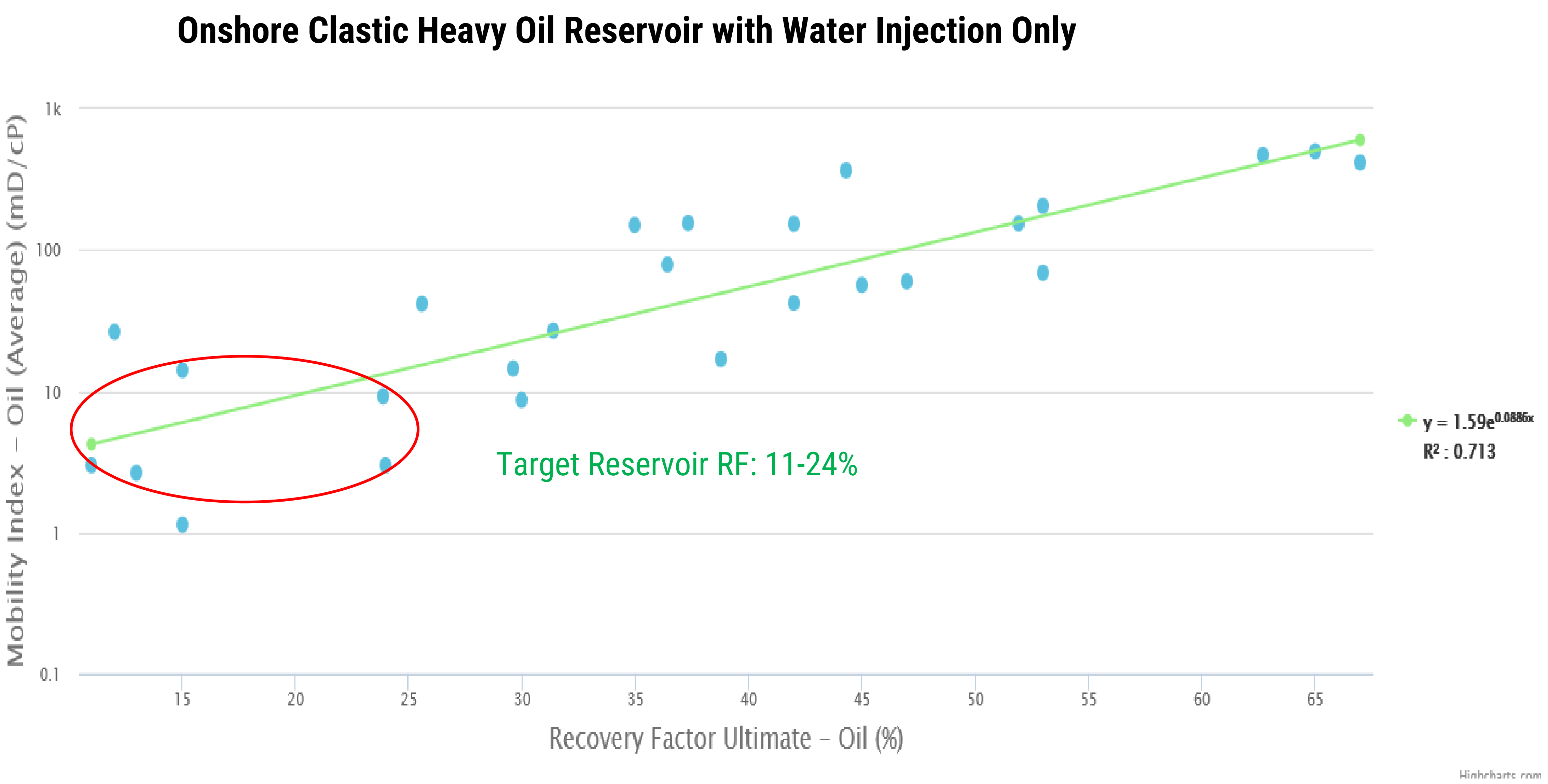
Gas Injection Analogues, Fractured Microporous Oil Reservoirs

Field Name	Reservoir Name	Onshore/Offshore	Drive Mechanisms	Gas Cap	Trap Flank Dip (degrees)	Gross Thickness (ft)	Gas Injection	Recovery Factor Ultimate
Point Arguello	Monterey	Offshore	• Solution gas • Gravity drainage	No	23	Unknow	Gas recycling	8.9
Lisburne	Wahoo (Lisburne)	Onshore	• Solution gas • Gas-cap expansion	Yes	1.5	700	Gas recycling	9.4
Tyra	Chalk Group	Offshore	• Gas expansion • Solution gas • Gas-cap expansion	Yes	2.5	530	Gas recycling	20
Natih	Natih	Onshore	• Solution gas	No	3	1325	Hydrocarbon gas injection (GOGD)	21
Fahud	Natih	Onshore	• Solution gas • Gravity drainage • Gas-cap expansion	Yes	15	1440	Hydrocarbon gas injection (GOGD)	30
Eldfisk	Hod-Tor-Ekofisk	Offshore	• Solution gas • Compaction	No	15	480	Gas recycling	31
Safah	Shuaiba	Onshore	• Solution gas • Gas-cap expansion • Moderate aquifer	Yes	0.5	110	Hydrocarbon gas injection	40
Ekofisk	Tor-Ekofisk	Offshore	• Compaction • Solution gas	No	3	820	Gas recycling	52

Test Viability of EOR Methods



Recovery Factor Trend



Thank You!