Final Report to

IOR for Deepwater Gulf of Mexico

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Improved Recovery: Phase I
07121-1701

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Abstract

This report documents the results of an 18-month study on identifying concepts for improving oil recovery in deepwater fields of the Gulf of Mexico. Knowledge Reservoir was the principal investigating company, and partner contributing groups included the Louisiana State University and Anadarko Petroleum.

The project first identified the “size of the prize” which is the forecast of oil recovery and remaining oil in-place at cessation of production under current operating practices. A comprehensive database was provided as a deliverable with detailed information for over 80 fields and 400 reservoirs with original oil in-place, rock and fluid properties, cumulative oil, and forecasts of expected ultimate oil recovery. A detailed evaluation of why oil is being left behind, referred to as oil trapping mechanisms, was a precursor to selecting relevant IOR process. For Neogene age reservoirs, the forecast average oil recovery factor is 31.6% with a range from 16% (P90) to 48% (P10).

For mature Neogene age reservoirs, a total of 19 IOR processes were identified and evaluated. The 19 IOR processes were included under the broad categories or themes of water injection, water-based EOR, gas injection, gas-based EOR, pumping and artificial lift, and well technology. The evaluation includes an estimation of the low and high range of “technical” incremental recovery, number of target fields, target OOIP, unrisked IOR potential barrels, risking by use of the “technical readiness factor” and ranking of the processes.

Key findings include that water injection and particularly low cost alternative like aquifer dump flooding and seafloor injection have highest near-term benefits. Pumping and artificial lift solutions are key required technology, and lower cost well is also crucial to all incremental projects. Other IOR processes which show potential and are recommended for further study include low salinity water injection, MEOR, and nitrogen injection, riserless light well intervention, and fracturing technology.

A key element of the study was to identify the technical gaps which are currently keeping the industry from implementing the IOR concepts. Recommendations were made for future research to help “bridge” the identified technical gaps.

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Project Information: RPSEA Sub-contract #07121-1701

Research Partnership to Secure Energy for America (RPSEA) is a non-profit research consortium with more than 145 members, including 25 US research universities, 5 US national laboratories, other major research institutions, large and small energy producers, and energy consumers. Its mission is to provide a stewardship role in ensuring the focused research, development, and deployment of safe, environmentally-sensitive technology that can effectively deliver hydrocarbons from domestic resources to the citizens of the US.

RPSEA was chosen by the US Department of Energy's National Energy Technology Laboratory (NETL) to manage a public-benefit research program set up by the US Congress in the Energy Policy Act of 2005, funded from lease bonuses and royalties paid by industry to produce oil and gas on Federal lands. An element of this research program is the identification and development of new methods of exploring for, producing, and transporting-to-market hydrocarbons from deepwater (> 1,000 ft) and ultra-deepwater (> 5,000 ft) Gulf of Mexico.

As part of RPSEA's overall research roadmap for the Gulf of Mexico (GOM), and following competitive bidding, RPSEA awarded sub-contract #07121-1701 to Knowledge Reservoir, LLC of Houston, to investigate improved oil recovery (IOR) processes. Knowledge Reservoir's partners in this effort are Louisiana State University (LSU) and Anadarko Petroleum.

Most IOR processes are currently difficult to implement and often not economically feasible in the challenging environment of deepwater and ultra-deepwater (collectively, DW) GOM. The objectives of sub-contract #07121-1701 are to identify the most prospective IOR processes for the DW GOM; to identify "technology gaps" which are currently preventing the application of those IOR processes; and to identify avenues for future research and development which might bridge those technology gaps and make those IOR processes economically viable in DW GOM.

In subsequent work (beyond the scope of this sub-contract), RPSEA may seek appropriate partners and invest funds in research and development projects to advance those identified IOR processes to commercial practicality for application in the deep waters of the Gulf of Mexico.

1 Executive Summary

Knowledge Reservoir is pleased to present this final report to Research Partnership to Secure Energy for America (RPSEA) for consultative services on IOR processes for deepwater and ultra-deepwater Gulf of Mexico, pursuant to sub-contract #07121-1701.

The data from more than 80 oil fields and 450 reservoirs developed in the deepwater Gulf of Mexico has been used for scoping potential improved recovery processes. A reasonably complete database exists for these fields including rock and fluid properties, production performance, and estimates of original oil in-place (OOIP) and forecast recovery. The data and performance of these fields and reservoirs is provided as a knowledgebase included with the deliverables of this work. IOR needs and resource potential have been evaluated separately for the Neogene and Paleogene age reservoirs due their significant differences in properties, drive energy and expected oil recovery.

Mature production experience in the deepwater is from Neogene age (Miocene, Pliocene, and Pleistocene is included) reservoirs. The forecast oil recovery factor ranges from 16% - 32% - 48% (P90-P50-P10) with waterflooded reservoirs excluded. Due to typically over-pressured and highly compacting reservoirs, water injection has been implemented in only 12 fields, and in many of these fields only minor water was injected. Water injection projects have in general been very successful in achieving oil recovery greater than 45%.

The Paleogene age reservoirs are in the exploration and appraisal stage, and only the Great White, Tobago, and Silver Tip fields, jointly the Perdido development in Alaminos Canyon, started production in 2010. They are included in this work because of the importance in planning for “life-of-field” needs for offshore installations and the significant challenges faced with exploiting these reservoirs. Much of the discovered OOIP in Paleogene age reservoirs is in the Keathley Canyon and Walker Ridge protraction areas. For fields in these areas, the forecast of primary oil recovery is only 10% of OOIP.

There is a large target for improved oil recovery. Table 1 summarizes the discovered OOIP, expected recovery, and the “size of prize” or forecast of remaining oil at cessation under current operating practices.

Table 1: Discovered OOIP, forecast RF and remaining oil in-place

	Neogene	Paleogene	Discovered Total
OOIP (billion STB)	31	25	56
Oil EUR (billion STB)	9.8	2.5	12.3
RF	31.6%	10%	
Remaining OOIP (billion (STB)	21	23	44

There is a large variation on the forecast of oil recovery across the database of 80 fields and 450 reservoirs as shown in Figure 1. The variation represents differences in geologic

complexity, natural aquifer influx ranging from little to infinite acting, oil properties ranging from medium gravity (API 28 and GOR 800 SCF/STB) to volatile (API 40 and GOR 2000) and infrastructure constraints (subsea tie-backs vs dry tree facilities). The approach in this study was to therefore to look at broad themes for IOR which have the potential to impact a large number of fields and reservoirs.

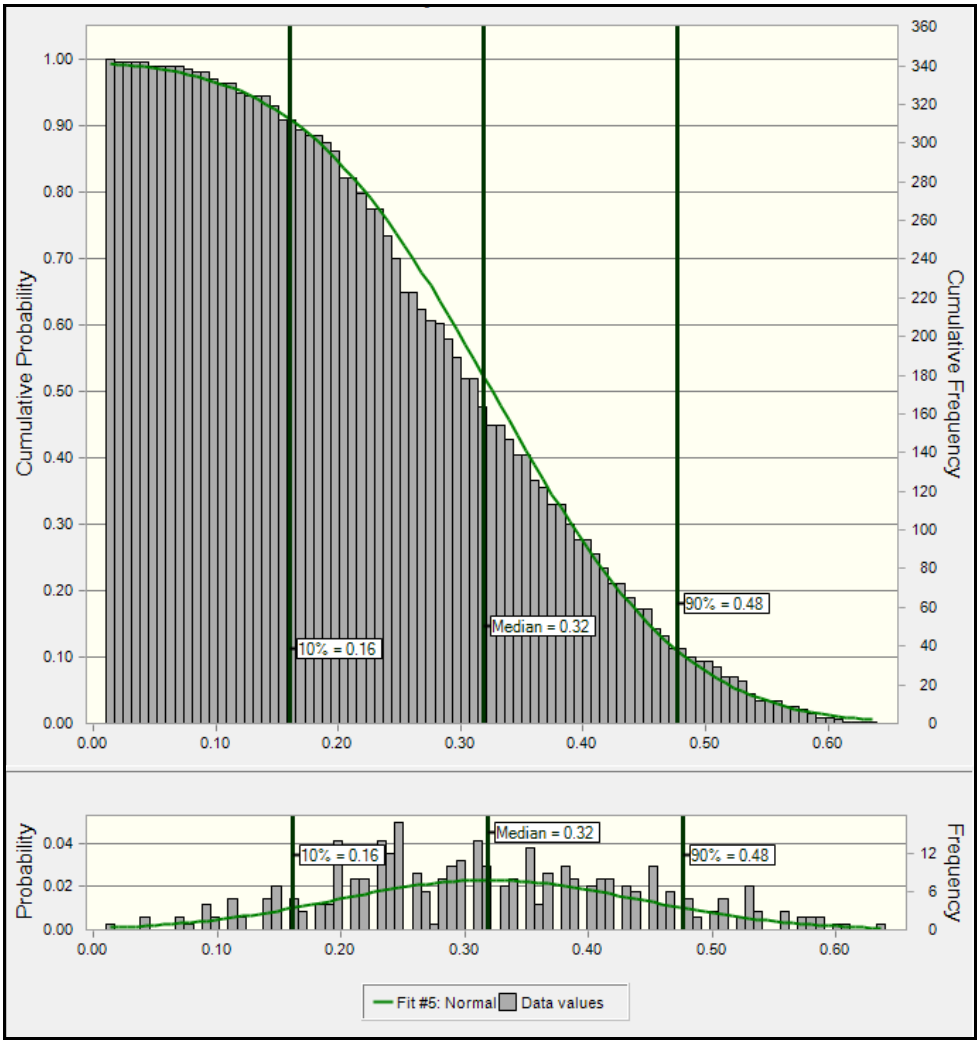


Figure 1: Oil recovery factor statistics in Neogene age reservoirs not waterflooded

A key metric from the database which affects the potential for implementing IOR projects is reservoir size. A distribution of Neogene age reservoir size is shown in Figure 2. It is observed that only 20% of the OOIP is tied up in 80% of the number of reservoirs meaning there are many small reservoirs. The application of IOR in small reservoirs will be difficult, and commingling of multiple zones may be necessary for improved project economics. The plot also demonstrates that approximately 50% of the total OOIP is present in the 25 largest reservoirs.

An analysis was made of the oil trapping mechanisms or the reasons oil is expected to be left behind. This was a precursor to determining the IOR needs for deepwater Gulf of Mexico reservoirs. A summary of the forecast produced volume and the trapped oil mechanisms for the remaining OOIP are shown in the pie chart of Figure 3.

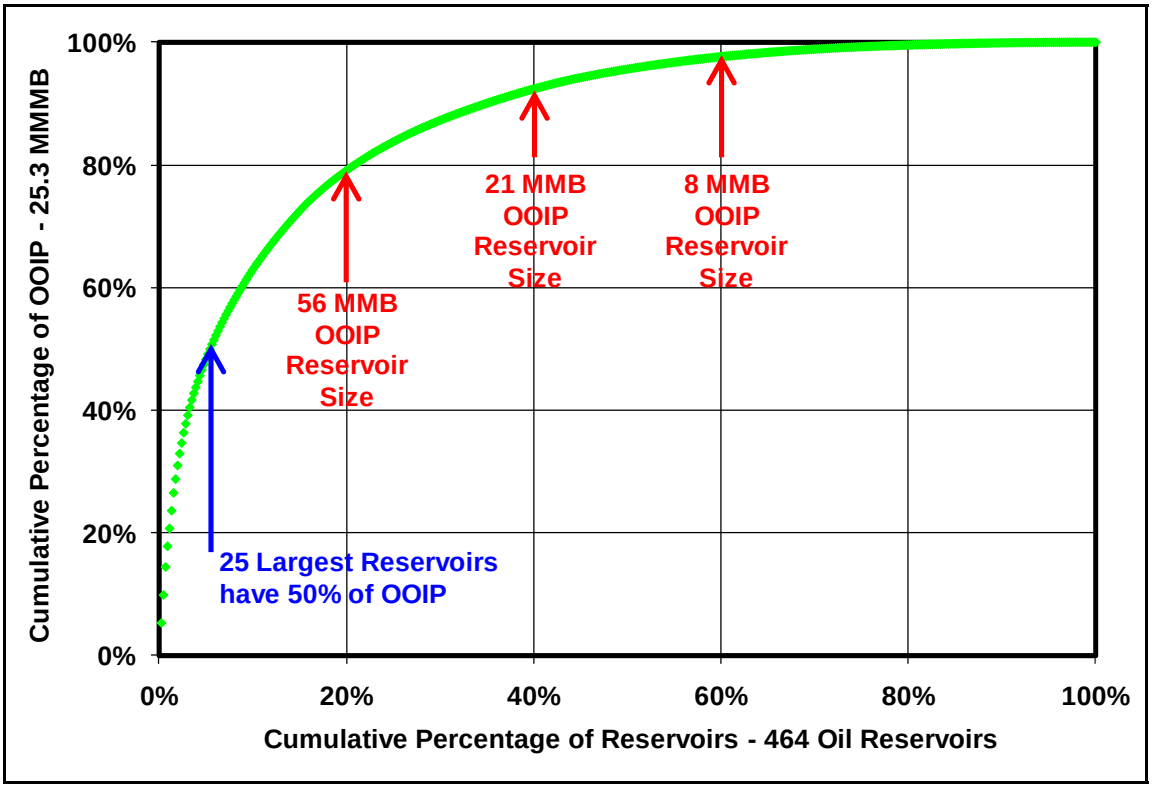


Figure 2: Cumulative % of Neogene OOIP vs cumulative number of reservoirs

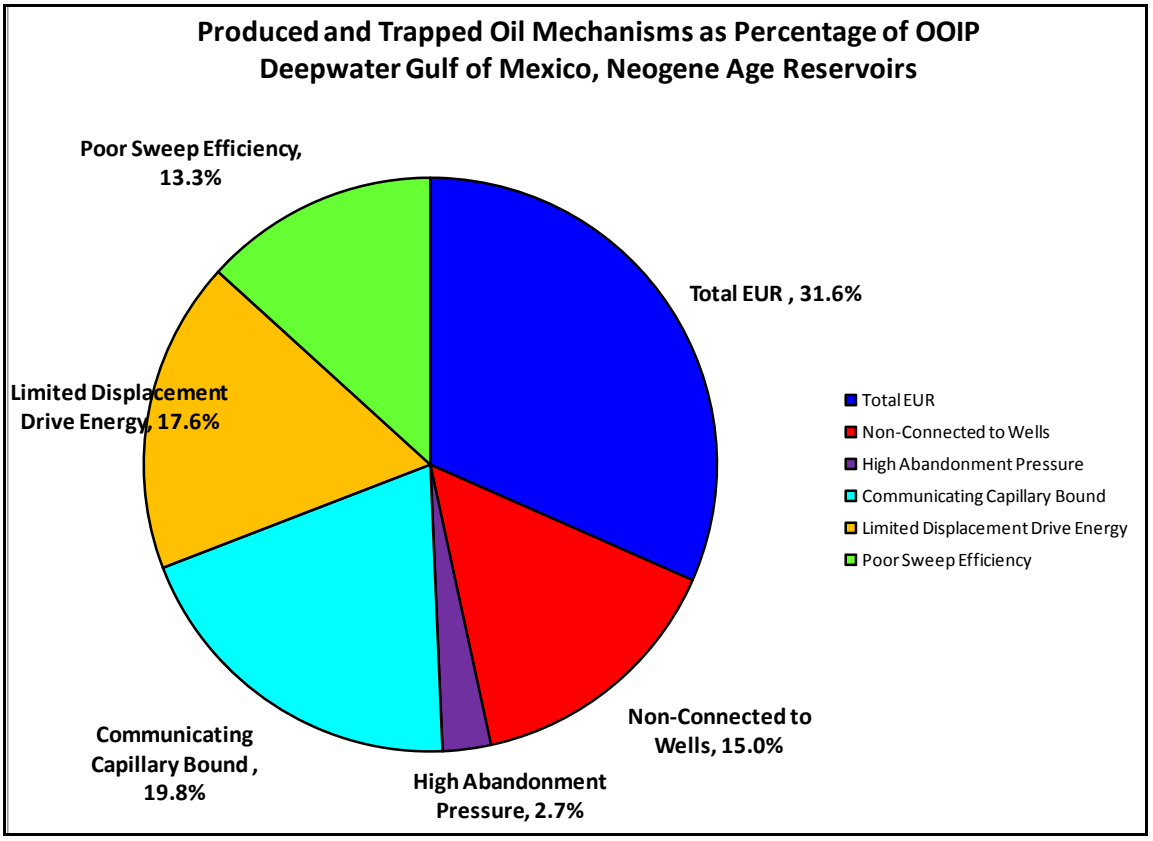


Figure 3: Produced and trapped oil mechanisms as % of Neogene discovered OOIP

Based on the study of oil trapping mechanisms, several themes for Neogene IOR potential were identified. They include the following:

1. There is a need to add reservoir energy to displace trapped oil from limited drive energy and poor sweep efficiency. Water injection is most favorable due to the robust gas sales infrastructure.
2. There is need for well technology or lower cost wells to target small fault blocks with stranded oil or the OOIP "non-connected to wells."
3. Subsea boosting and artificial lift are key IOR technologies for optimizing primary production and enhancing secondary recovery permitting flow to higher water cut.
4. Hybrid technology, a low cost addition to water or gas injection, is needed to displacing capillary bound fluid. Leading alternatives are low salinity water injection and microbial EOR.

The Paleogene age reservoirs in Keathley Canyon and Walker Ridge have significant oil recovery challenges, and there is currently no producing experience from these reservoirs. No suitable analog was found to benchmark expectations of reservoir performance. The development risk is high due to reservoir depth, high pressure, high temperature, complex geology, and rock and fluid properties. The Paleogene requires critical new technology for primary production and development.

A forecast was made of trapped oil mechanisms for the Paleogene reservoirs in Keathley Canyon and Walker Ridge. A total of 69% of OOIP is forecast to remain after primary production practices due to limited drive energy, capillary bound fluids and poor sweep efficiency (see Figure 50). Based on the study of oil trapping mechanisms, several themes for Paleogene IOR potential were identified. They include the following:

1. Similar needs to the Neogene are adding reservoir energy, for well technology, and for subsea boosting and artificial lift.
2. Technology is needed for cost effective reservoir management and improvement of sweep efficiency from a thick, heterogeneous reservoir.
3. Advancements in hydraulic fracturing are required to enhance well productivity and injectivity for deep (>20,000 ft) reservoirs with permeability below 30 mD.

IOR concepts were developed separately for the Neogene and Paleogene. A total of 19 concepts were evaluated for the Neogene and 10 were evaluated for the Paleogene. Each process was evaluated for high and low incremental recovery factor, target number of field applications and OOIP, technical readiness factor, and ranking based on risked IOR potential. Economic evaluation has not been included since each field application would require specific review.

Table 2 is a summary of the Neogene IOR concepts considered most favorable. The top 6 include three types of water injection and three forms of well boosting. Two low cost alternatives to conventional water injection, seafloor water injection and aquifer dump flooding, are considered important for more widespread application of waterflooding.

The technical readiness level (TRL) was adapted from the DeepStar consortium and reflects the maturity and risk of the IOR process. A TRL level of 7 is proven technology in the deepwater Gulf of Mexico environment while level 0 is an unproven concept. The TRL is used to risk the P50 incremental recovery potential, and the processes were ranked from highest to lowest risked incremental oil.

Low salinity water injection shows great potential with a large number of possible applications and relative low cost of implementation. The TRL level is low at 2 since the technology has not

been implemented and proven in a full field EOR project onshore let alone offshore. However, the LowSal technology is rapidly advancing, and existing nano-filtration equipment for offshore sulfate removal from seawater can possibly be adapted and enhanced for LowSal.

Other processes which ranked low but are considered important due to the number of field applications and the target OOIP are low cost well intervention and low cost wells.

Table 2: Neogene prioritized IOR concepts

	Technical IOR RF		Applications			
IOR Process	Low	High	Field Count	Target OOIP of the field (MMSTB)	Technical Readiness Level	Process Ranking
Conventional Water Injection	4%	25%	14	10,021	7	1
Seafloor Water Injection	4%	18%	18	10,350	4	2
Aquifer Dump Flooding Injection	4%	18%	18	10,350	4	3
Subsea Multi-Phase Pumping	3%	7%	23	10,948	7	4
In-Well ESP	3%	7%	13	12,221	6	5
In-Well Gas Lift	3%	7%	21	10,518	6	6
Hydrocarbon Gas Injection	3%	12%	5	7,096	5	7
Nitrogen Injection	3%	12%	8	7,980	4	9
Low Salinity Water injection	3%	7%	26	22,371	2	11
Low Cost Well Intervention	1%	4%	47	12,530	5	13
Microbial EOR	1%	5%	5	7,177	3	16
Low Cost Wells	4%	9%	74	29,748	0	18

Similar to the Neogene, water injection and subsea pumping and artificial lift solutions were ranked highest for having the most risked IOR potential in Paleogene reservoirs (see Table 46). Other key technologies required specific to the Paleogene are as follows:

1. Technology for reservoir management of water injection and production from a thick, heterogeneous reservoir. This includes downhole data acquisition (pressure, rate, water cut) and control equipment for multi-zone completions with remote operation or control by riserless light well intervention (RLWI) vessel.
2. The development of chemical diverting agents for water injection profile control may be a viable alternative to mechanical solutions for improving sweep efficiency. MEOR diverting agents which do not degrade long term injectivity are a possible solution.
3. Advancements in hydraulic fracturing (fluids, proppants, pumping equipment) to enhance productivity and injectivity in reservoirs with permeability below 30 mD.

The deepwater Gulf of Mexico for the most part is in the early development life-cycle. The near-term IOR needs are for optimization of primary production and the implementation of secondary recovery schemes; therefore, EOR processes like CO2 and chemical injection are not applicable in the near term.

Gaps in the available IOR technology have been identified which inhibit their use. A prioritized list of the most important technical gaps is provided in Table 3. A list of recommended future work for attempting to "bridge" the technical gaps is provided in Table 4.

Table 3: Technical Gaps for IOR implementation

Process	Technical Gaps
Enabling Technology	▪ Improved reservoir characterization with seismic imaging tools, dynamic data, and modeling tools to reduce the risk of poor forecasting. ▪ The high cost of wells and its impact on project economics.
Conventional Water Injection	▪ Paleogene waterflood management in a high cost environment for deep, high pressure reservoirs with thick (>1000 ft) of interbedded sand/shale.
Seafloor Water Injection	▪ Accurate and reliable tools for the forecasting of scaling, corrosion, and reservoir souring potential and treating requirements. ▪ Combine the potential of MEOR recovery benefits with the injection of untreated and aerated brine.
Aquifer Dump Flooding	▪ Development of a reliable dual completion to source aquifer water and inject into the same wellbore with downhole control and metering.
Low Salinity Injection	▪ Comprehensive pore-scale model that adequately explains the displacement mechanisms. ▪ Adaptation and expansion of the sulfate removal nano-filtration technology to reduce seawater salinity to < 5000 ppm.
MEOR / Diverting Agents	▪ Hybrid microbial process to improve waterflood sweep efficiency by acting as diverting agent and in reducing capillary bound fluids.
Nitrogen Injection	▪ Light-weight, small footprint, and cost effective design for offshore nitrogen extraction plant.
In-well ESP / HSP	▪ Downhole pumping solution for deep Paleogene completions to boost production to remote host and lower abandonment pressure.
Low Cost Well Intervention	▪ Riserless light well intervention (RLWI) or other solutions to manage and prolong the life of subsea wells. Included is the need to access subsea wells for artificial lift remediation and waterflood management.
Hydraulic Fracturing	▪ Transfer onshore tight reservoir fracturing to deep, high pressure Paleogene to enhance well PI by a factor of 3 times. ▪ Design of custom fracture fluid and proppants needed for long service time in high temperature (>250 F) and high overburden stress.

Table 4: Recommendations for future work to bridge technical gaps

Technical Gap	Recommendations to Bridge Technical Gaps
Reservoir Characterization	▪ Research and development in "next generation" seismic tools. ▪ Research for new technology which replaces the pressure impulse from dynamic data to determine reservoir connectivity.
Conventional Water Injection	▪ Joint industry initiative of operators and service providers to develop "fit for purpose" Paleogene completions in wet tree wells which can be serviced with RLWI vessels or other low cost options.
Seafloor Water Injection	▪ Research funding to capture lessons learned from the North Sea on the evaluation, design and performance of seafloor ("rawwater") injection. Where necessary, the tools for predicting reservoir souring, corrosion, and scaling and mitigation methods should be improved with history matching of operating seafloor injection installations. Additional benefits may be possible with the injection of aerated water for stimulating MEOR activation and enhancing recovery which is currently under trial in the Statoil Norne field.
Aquifer Dump Flooding	▪ Funding of a study for advancing the application of aquifer dump flooding in several fields where drive energy is required. Evaluate aquifer size and compatibility, and begin discussions with regulatory body, BOEMRE (formerly MMS), on the requirements for receiving permits. Also, work with service providers on the feasibility of a dual completion (source and injection) with downhole control and rate measurement.
Low Salinity Injection	▪ Funding of research for the evaluation of the potential of low salinity water injection in Gulf of Mexico reservoir cores. Develop an understanding of the reservoir recovery mechanisms for applying low salinity injection in secondary and tertiary recovery modes. Work with vendors in the development of membrane technology for offshore desalination.
MEOR / Diverting Agents	▪ Fund research into extending the microbes used onshore for MEOR to the higher temperature and large well spacing found in deepwater. Develop microbes for use in waterflooding to dynamically divert injected water over a large completion interval to improve sweep efficiency.
Nitrogen Injection	▪ Funding of research for the sourcing of nitrogen onshore or generation offshore for a centrally shared infrastructure site for use in multiple fields. One area to consider is in the area of the K2 field which has surrounding fields with requirements for adding drive energy. Determine from a pilot study the technical and economic gaps for an IOR project of this type.
In-well ESP / HSP	▪ Research and development of a design basis and operating requirements for a downhole pumping system for Paleogene oil wells. Consider electric and hydraulic pumping alternatives for the delivery of a high head generating centrifugal pump.
Lower Cost Wells	▪ Research funding with participation by operators to evaluate a "paradigm shift" in drilling technology and well cost.
Low Cost Well Intervention	▪ Formation of a Paleogene operator's group to define "life-of-field" intervention and reservoir management requirements for producers

	and injectors so that low cost, rig-less activities can be performed.
Hydraulic Fracturing	▪ Research coordinated with operators and service providers to design hydraulic fracturing technology for application in the Paleogene reservoir environment with the objective of > 3 fold increase in well PI.
Shared Infrastructure	▪ Funding of an industry study group to evaluate a “brownfield” implementation of LowSal, Nitrogen, MEOR or CO2 injection in the Chevron/Marathon Petronius field for tertiary recovery. Include operators from the nearby Neptune, King, Swordfish, Horn Mountain, and Ram Powell fields to gauge interest in the use of a shared facility for low salinity water or other injectant supply.

Knowledge Reservoir and its evaluation partners the Louisiana State University and Anadarko Petroleum express our thanks to the working committee of RPSEA. The working committee, made up of engineers and geoscientists from major operators, has been instrumental in providing guidance and insight based on their experiences in deepwater Gulf of Mexico operations.

2 Introduction

"Deepwater" oil and gas are simply conventional reserves in an unconventional setting. They constitute a resource class of their own largely because they face a common set of technological challenges in the course of their identification, development, and production" (NPC Global Oil and Gas Study, Topic Paper #20, 2007). For the purposes of this work, we have used the Minerals Management Services (MMS) definition of deepwater fields being those in water depths greater than 1000 feet.

Historically, deepwater production in the Gulf of Mexico began in 1979 with Shell's Cognac field. New technology is continuously being used to develop new fields and to optimize production from existing fields. Therefore, improved oil recovery (IOR) methods have and will continue to be employed, and the investigations and analyses reported in this work are merely a snap-shot of concepts for continuous improvement in hydrocarbon recovery.

The report section "Deepwater GOM Resource Base" provides a snap-shot of the forecast of ultimate recovery and remaining oil and gas in discovered fields. These forecasts will be conservative since they assume that the current operating practices of those fields will not change. Many of the deepwater fields are in the early stages of development, and only a small number are mature and in need of secondary and tertiary recovery methods.

2.1 *Project Focus on IOR*

Gas has historically been the predominant hydrocarbon produced from the Gulf of Mexico, accounting for about 2/3 of the cumulative production from the entire OCS in the GOM. However, this project for RPSEA is focused on improved oil recovery, for several reasons.

First, the need is larger in the case of oil fields. The ultimate recovery factor from gas fields is typically high because of the greater mobility of gas in subsurface reservoirs. Secondly, as the focus of exploration has moved to deeper waters, an increasing portion of the discovered hydrocarbons are oil reservoirs. The deeper water depth and deeper depth of the oil-bearing formations has increased the challenges of economic recovery, and a higher percentage of hydrocarbons are forecast to be left behind. The target for IOR continues to increase with the challenges of the newer discoveries.

2.2 *Reasons Oil Gets Left Behind*

The fundamental driver for leaving oil behind is economics.

In general terms, the process of recovering oil from any conventional reservoir requires (a) a pathway which connects oil in the pore space of a reservoir to the surface, and (b) sufficient energy in the reservoir to drive the oil to the surface. Oil gets left behind because of lack of a pathway or lack of adequate reservoir energy in an environment in which it is not economical to implement incremental development activities.

In addition, even where there is a pathway and adequate reservoir energy, conventional displacement by water or gas will not recover all of the theoretically displaceable oil, due to the physics of fluid displacement in porous media.

In practical terms, oil left behind in DW GOM reservoirs can be classified under a variety of "oil trapping mechanisms":

- Non-development of the reservoir
- Premature abandonment, due to a range of facility and pipeline issues
- High reservoir pressure at abandonment
- Reservoir volumes not connected to wells, due to compartmentalization
- Lack of an adequate natural or engineered fluid displacement drive mechanism
- Incomplete sweep conformance in zones with a fluid displacement drive mechanism
- Capillary forces which hold residual oil in the pores of the reservoir

Over the decades, industry has developed a wide range of IOR (IOR) processes which can access much of the oil left behind due to those trapping mechanisms. The challenges to increasing ultimate recovery are economic realities and technical risks.

Lease-holders in DW GOM have every incentive to do an excellent job of maximizing oil recovery from their fields. The operators have significant sunk costs in bidding and securing the leases, exploratory drilling, and field development costs. With all of those costs sunk into a field development, participants clearly have a tremendous incentive to maximize oil recovery and earn back their investments.

2.3 *Study Objectives*

According to the "Deepwater Gulf of Mexico 2007; Interim Report of 2006 Highlights" (Outer Continental Shelf (OCS) Report, Minerals Management Services (MMS) 2007-021), the proved reserve base in the deepwater and ultra-deepwater Gulf of Mexico (GOM) is 9 billion barrels of oil equivalent (BOE), but many of these fields have recovery factors as low as 15 – 25% from primary recovery. The oil remaining in these fields is significant and provides the incentive for the development of processes and methodologies to unlock these additional residual barrels.

The identification of improved recovery opportunities in the early stages of field development planning is critical such that the facility and well designs can be optimized to take advantage of those opportunities.

The following are the RPSEA #07121-1701 project objectives as agreed between the working committee and Knowledge Reservoir:

- Identify IOR processes for the deepwater Gulf of Mexico which could add substantial reserves
- Identify the "technical gaps" preventing application of those IOR processes
- Recommend future R&D programs to bridge those technical gaps

A number of specific tasks were defined within the described objectives: characterize the deepwater assets to determine the performance and reservoir properties; compile and categorize key causes of trapped/remaining hydrocarbons in the deepwater reservoirs; identify the technology gaps in improving recoveries; and prioritize "high-value" concepts for closing gaps. The flow chart shown in Figure 4 was used by the working committee to convey their vision of the project work steps.

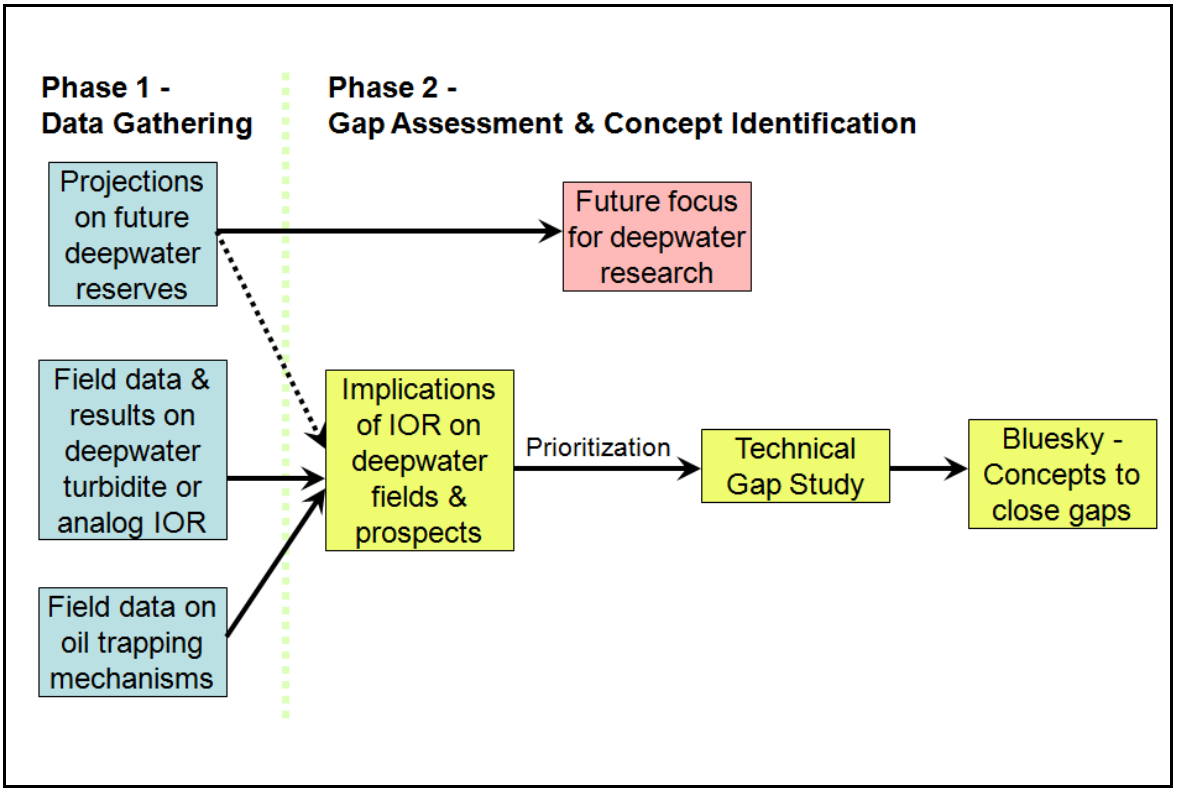


Figure 4: Project work stages as defined by RPSEA Working Committee

The study was conducted over the period of February 2009 until end of September 2010. Contributing companies include Knowledge Reservoir for project management and technical analysis, LSU for analog IOR review and technical analysis, and Anadarko Petroleum Corp. (Anadarko) for the contribution of the K2 field data where extensive IOR research was performed.

The following report is a summary of the workflow, methodologies used, lessons learned from analog IOR projects, IOR processes evaluated for the Gulf of Mexico, and the recommendations for most favorable “near-term” IOR potential. Additional interim reports have been provided to the RPSEA organization on specific sub-topics which contain considerable additional detailed information and results.

3 Methodology and Analysis

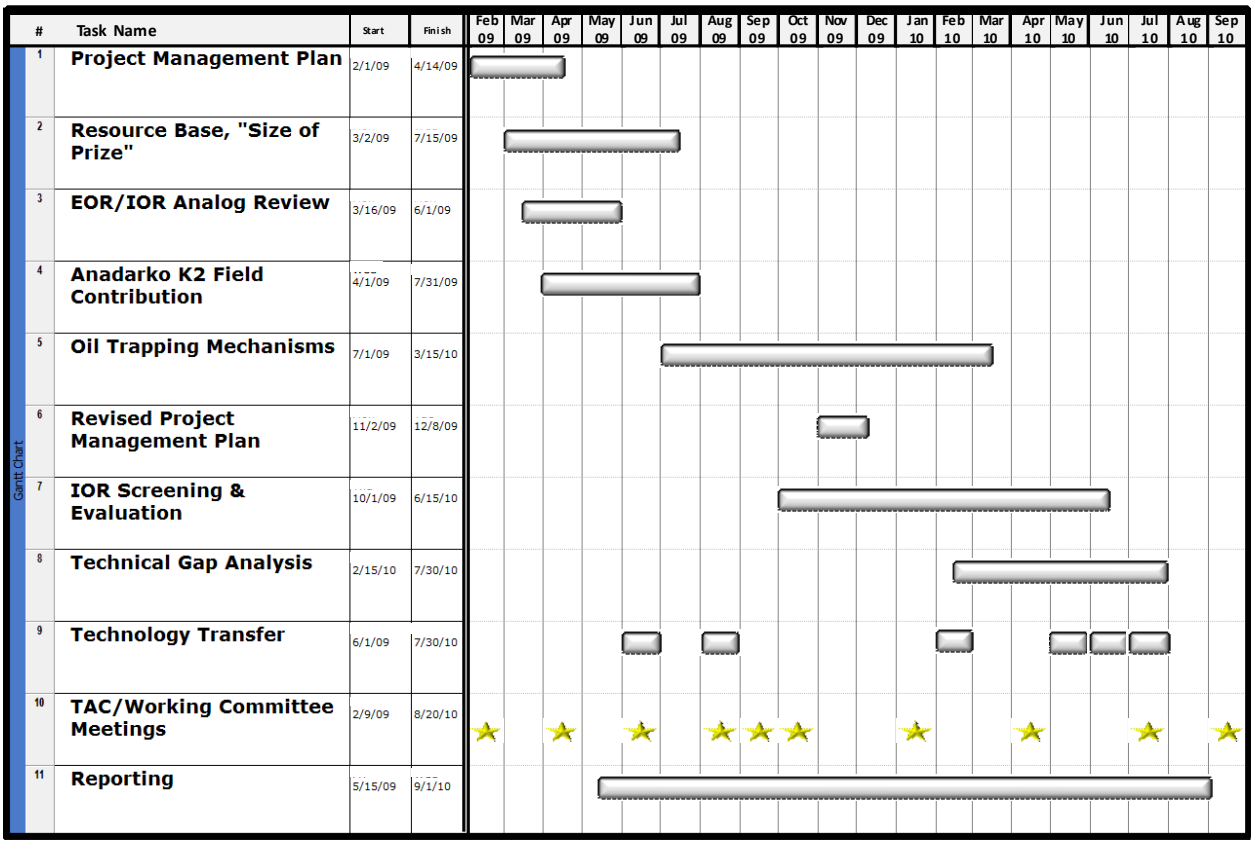


Figure 5: Project major work steps and Gantt chart

The project major work steps and a description of each are summarized below.

- Resource base, “size of the prize”
  - The project team compiled publicly available data from the MMS web site and interpretations provided in ReservoirKB©, a subscription database on field and reservoir performance. Data was compiled for 83 oil fields containing approximately 410 reservoirs. Detailed information is available on production performance, original oil in-place (OOIP), analysis of expected ultimate recovery (EUR), and reservoir rock and fluid properties. The collected database and oil recovery forecasts are used in future phases of the project to determine applicable IOR processes and potential incremental recovery.
- EOR/IOR analog review
  - LSU provided a focused review of the experience in applied IOR worldwide and lessons learned. Priority in the search for analogs was as follows: projects done in deepwater basins; experience in turbidite geology (deepwater depositional systems); all offshore fields/basins; particular IOR/EOR processes of interest for the DW GOM. A separate report has been provided by LSU. The report is not a complete worldwide survey of all IOR projects, but is focused on concepts identified for potential use in the DW GOM.
- Anadarko K2 field contribution

  - Frank Lim, EOR Advisor with Anadarko, provided peer assistance and guidance as an expert in EOR/IOR evaluation and with particular experience in the evaluation of IOR at the K2 field in DW GOM. The K2 field started producing in 2005, and early performance showed minor to little aquifer influx and reservoir drive energy. A low oil recovery, below 20%, was forecast which led Anadarko to begin the evaluation of IOR methods to improve recovery. The analysis by Anadarko including laboratory core and PVT study data have been contributed to this RPSEA project.

- Interviews with industry experts
  - The project included interviews with oil industry experts to help identify and prioritize IOR (IOR) concepts and opportunities for deepwater Gulf of Mexico. The interviews built on earlier workshops organized by the US Department of Energy in 2000 and by RPSEA in 2005. Knowledge Reservoir interviewed 18 carefully selected individuals from industry, government, and academia with relevant widely-varying expertise and with a deliberately broad range of perspectives.
- Oil trapping mechanisms
  - Prior to identifying concepts for IOR, a detailed review was made to evaluate and quantify the physical reasons that oil is left unrecovered in DW GOM reservoirs. Once quantified, IOR concepts could be selected specifically to target the trapping mechanisms. The evaluation is made for two broad categories of reservoirs since their properties are different: the Neogene age Miocene and Pliocene, and Quaternary Pleistocene (all lumped together and called Neogene in this report) in which most of the production experience resides; and the older Paleogene where many of the recent large discoveries have been made but there is little production experience.
- Revised project management plan
  - The RPSEA working committee advised the team in October 2009 that the National Energy Technology Lab (NETL) would be creating a database of field and reservoir properties and IOR potential. It was determined that this project would no longer include delivery of a web-enabled Knowledgebase. However, the project will still deliver a database to RPSEA and NETL, in Excel, of the "Resource Database" as described in item (1) above. Also, a separate database of the properties, results and lessons learned from key analog worldwide IOR projects will also be provided in Excel format.
- IOR screening and evaluation
  - A long list of IOR and EOR processes were used as a starting point and reduced to a shorter list of processes most applicable to the DW GOM reservoirs and the trapped oil mechanisms described in (5) above. The evaluation was again done separately for the Neogene and Paleogene. The evaluation included setting ranges for low and high incremental recovery, determining the number of potential field applications, determining the unrisked P50 incremental "size of prize," evaluation of a technical readiness factor for each process, and finally risking the incremental potential so that a rough ranking could be made of the IOR processes. Originally, it was the intention of the group to provide indicative economics, like $/incremental barrel. However, Knowledge Reservoir and the working committee decided that the economics were too dependent on each particular field case and thus would be difficult to determine for the entire collection of Gulf of Mexico assets.

- Technical gap analysis
  - The barriers or reasons which are preventing operators from applying the “short list” of IOR processes applicable to DW GOM have been summarized. This includes perception of the subsurface risk, high cost of enabling technology like wells and completions, the technical readiness of the concept, and specific environmental or reservoir properties which make the Gulf of Mexico unique. Many of the technical gaps are defined also from experience in their application in other worldwide basins, both offshore and onshore. The objective of identifying technical gaps is to ultimately recommend future R&D to attempt to bridge the gaps.
- Technology transfer
  - A number of SPE and OTC technical papers and other conference presentations have been made during the project. The objective was to raise awareness of the RPSEA work and to build interest in future study participation for expanding on the identified IOR concepts. Presentations were made at the SPE Delta Section Deepwater forum in New Orleans in August 2009 and August 2010, presentation at the Deepwater Offshore Technology Conference in February 2010, paper OTC 20678 in May 2010, paper SPE 132633 presenting at the SPE Western Regional Conference in May 2010, presenting at the RPSEA forum in June 2010, presentation at the Deepwater Intervention Forum in Galveston in August 2010, and paper SPE 130927 for presentation at SPE ATCE in September 2010.
- Technical advisory committee and working committee meetings
  - Progress review meetings were held on a quarterly basis with the technical advisory committee (TAC meetings) and on a more frequent basis with the working committee. The working committee played an active role in steering the work within the vision of providing enabling technology to further exploit production in deep water. The working committee was made of senior advisors from Chevron, Anadarko, BP, StatOil, Shell, ConocoPhillips, Marathon, Total, Petrobras, and RPSEA
- Reporting
  - Several milestone reports are available including: “Resource Base – Size of the Prize,” “Industry Experts Interviews,” and “IOR Analog Review” by LSU. Additional reports have been generated on “Depositional and Structural Setting of Deepwater Gulf of Mexico,” “Chemical Flooding Analog Report” by LSU, and “Multi-scale Modeling of Relative Permeability Tensor Using Pore-scale and Field-scale Simulation of Multiphase Flow through Porous Media” by LSU. In addition to milestone and subject reports, a summary of all the study work, results, conclusions and recommendations can be found in this final report. Also, monthly reports have been submitted to the RPSEA SharePoint site for the tracking of technical and budget progress.

4 Background on Deepwater Gulf of Mexico

4.1 *Overview of Protraction Areas and Leasing*

For purposes of leasing, the US Federal Outer Continental Shelf (OCS) in the Gulf of Mexico is divided into protraction areas, generally about 70 miles north-south and 120 miles east-west (Figure 6). Most leasing has taken place in the Western and Central Planning Areas of the Gulf. Each protraction area is divided into 900 to 1,000 individual lease blocks, generally 3 miles by 3 miles (5,760 acres).

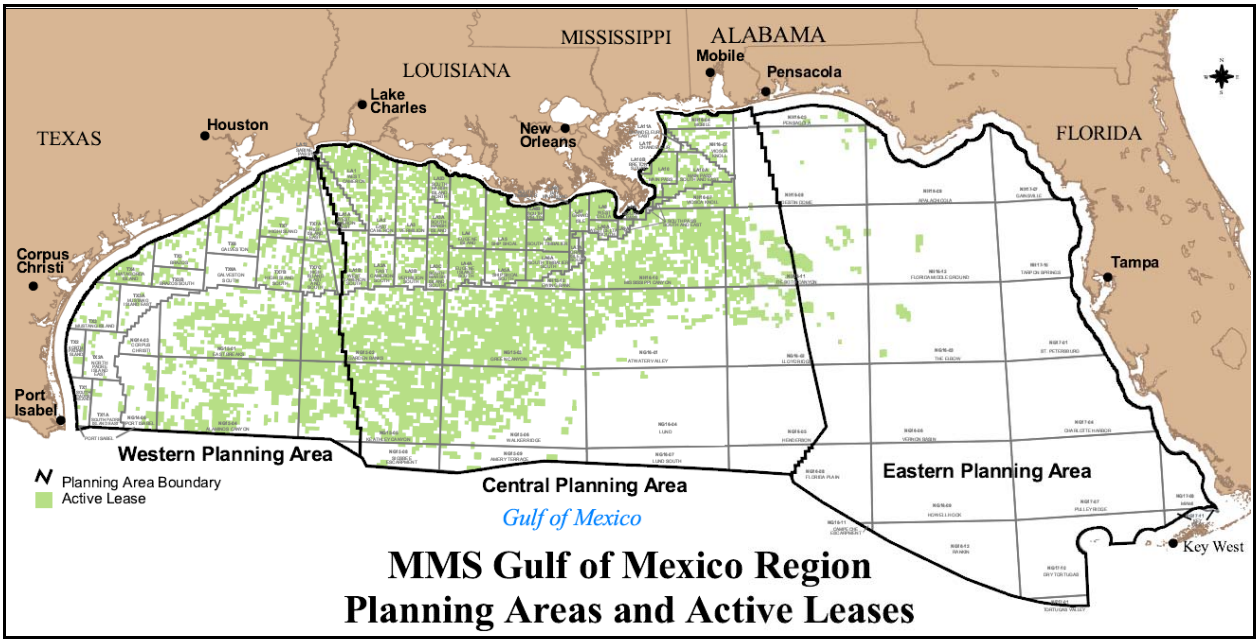


Figure 6: GOM protraction areas, planning areas and leasing activity (MMS, 2008)

At scheduled open auctions, blocks are leased to the high bidder for a limited period (generally 5-10 years). Lease holders who discover hydrocarbons can extend the term of the lease, and pay a royalty to the Federal government on produced hydrocarbons. Lease terms have varied substantially over the years. Royalty rates have varied from 12.5% of production up to 18.75%.

4.2 *Discoveries and Production*

Exploration and development of offshore oil and gas in the Gulf of Mexico began in the 1940s in the shallow waters of the shelf – gradually extending from water depths of tens of feet into hundreds. Beyond about 1,000 ft water depth, the continental shelf slopes off rapidly into much deeper waters.

The first discovery in deepwater GOM (> 1,000 ft water depth) was made in 1975. The first deepwater field to go on production was Shell's Cognac field in the Mississippi Canyon protraction area in 1979. This was followed by ExxonMobil's Lena field in 1984. First discovery in ultra-deep water (> 5,000 ft water depth) was the Mensa field in 1986. Since 1975 there have been over 300 deepwater discoveries in the GOM. At the end of 2008, there were 141 producing fields in the deepwater GOM (MMS 2009-016).

Deepwater oil production in 2007 was about 900,000 BOPD – about 70% of total oil production from the GOM. Deepwater gas production was about 3 BCFD – about 36% of total GOM gas production. (MMS 2009-016). Deepwater gas was equivalent on a BTU basis to about 520,000 Barrels Oil Equivalent (BOE) per day. Gas thus accounts for about 37% of the thermal value of current deepwater GOM production. This historical production of oil in shallow waters of the Gulf of Mexico versus production from the deep water is shown in Figure 7 and highlights the growing importance of the deep water.

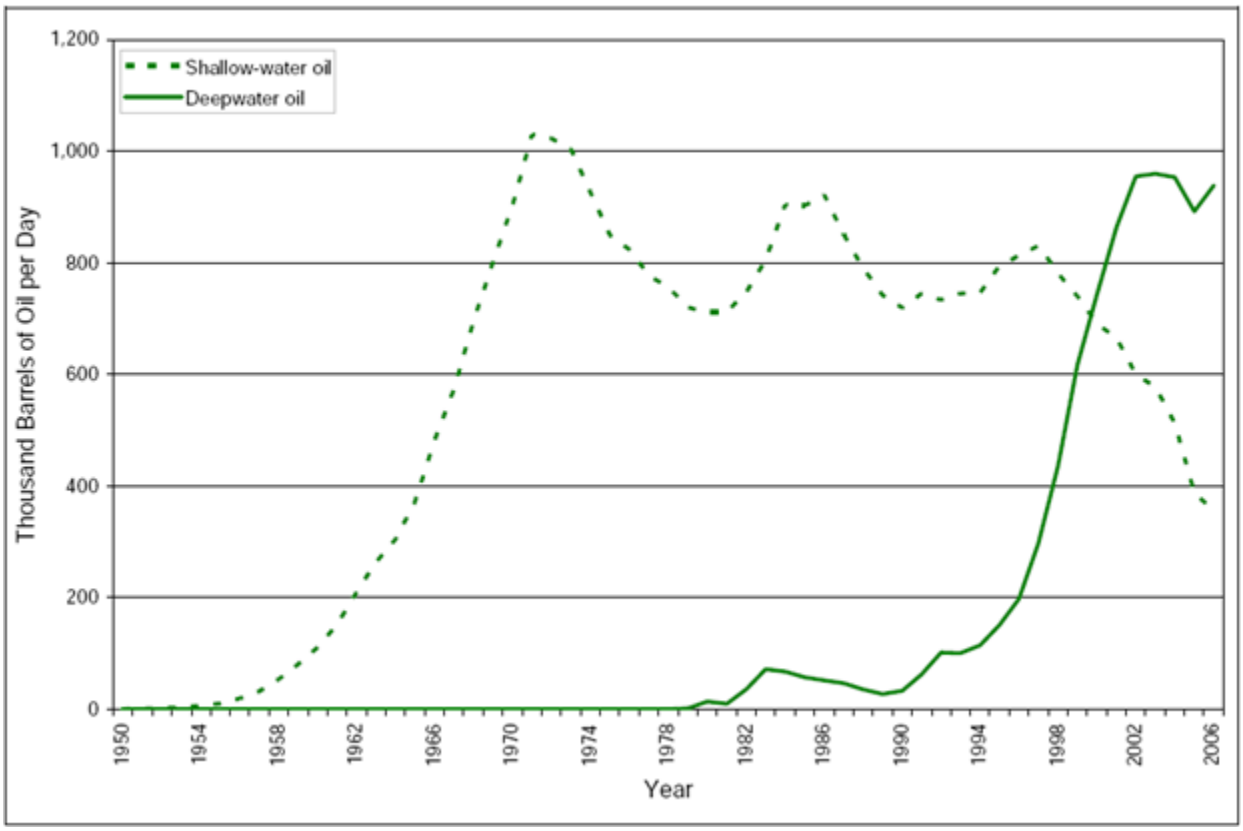


Figure 7: Historical shallow and deepwater Gulf of Mexico oil production (MMS, 2008)

As of 31-Dec-2004, EUR of oil from the deepwater protraction areas was estimated at 9.8 billion bbl – 7.2 billion bbl from proved fields, and 2.6 billion bbl from unproved fields, i.e. fields which have been discovered but not yet brought into production (MMS 2008-034).

For comparison with deepwater production, historically about 2/3 of the production from the Federal waters of the Gulf of Mexico (shelf and deep water combined) has been gas. Cumulative production from the entire GOM (shelf + deep water) as of end-2004 was 14.1 billion bbl oil and 160.7 trillion standard cubic feet gas, for a BOE of about 42.6 billion BOE (MMS report 2008-034).

As production has continued to move into deeper water depths, the percentage of total deepwater production produced from subsea (wet tree) wells has also increased. Another chart from the MMS publication “Deepwater Gulf of Mexico 2008: America’s Offshore Energy Future” shows the increasing importance of subsea technology (Figure 8). The figure shows that approximately 30% of the deepwater oil production in 2007 is coming from wet tree wells tied back to surface facilities through pipelines and riser systems. Subsea technology will have a large influence future improved oil recovery potential.

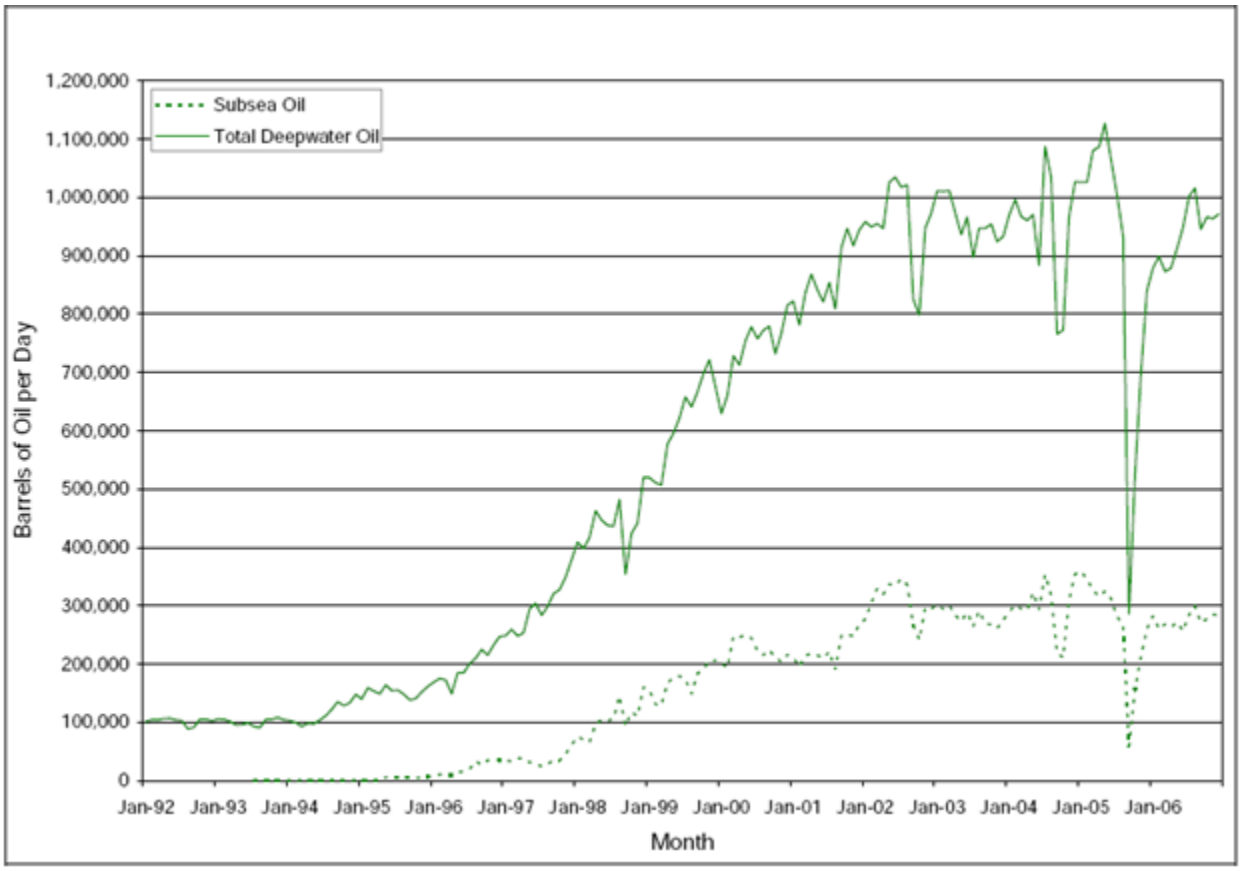


Figure 8: Contribution of deepwater oil production from subsea (wet tree) wells (MMS, 2008)

4.3 *Challenges in Deepwater Gulf of Mexico*

The most obvious challenge with exploration and development in the deeper waters of the Gulf of Mexico is the water depth itself.

Drilling technology has advanced dramatically over the past quarter-century, making exploration drilling possible in ever-deeper waters. The deepest water drilled to date has been Chevron's Toledo prospect (Alaminos Canyon) in 10,011 ft of water, in 2003. This depth is approaching the maximum water depth in the abyssal plain of the GOM at about 12,000 ft.

Such very deepwater depths have required continuous innovation in exploration, drilling, and production practices. In 2008, Shell set a world water depth record by drilling and completing a subsea well in 9,356 ft of water at the Silvertip project (Alaminos Canyon). The GOM is currently one of the major areas in the world for deepwater exploration and development. In 2008, about 29% of the world's ~120 deepwater drilling rigs were active in the US GOM. Other major areas for deepwater drilling are offshore Brazil and offshore West Africa.

A second challenge is that some of the target formations are found at extreme depth. In the central GOM, productive horizons have been found as deep as ~ 28,000 ft subsea. The deepest well drilled to date was Chevron/Unocal's Knotty Head (Green Canyon) discovery in 2005, which reached a total vertical depth of 34,158 ft. Such wells encounter extreme high pressure and high temperature (HP/HT) conditions, with formation pressures and temperatures exceeding 20,000 psi and 275 deg. F respectively.

A third challenge in the deep waters of the GOM is the presence over much of the area of a layer of allochthonous salt, which forms a subterranean canopy as much as 7,000 to 20,000 ft thick over potentially hydrocarbon-bearing clastic horizons. The southern edge of this salt canopy is expressed at the sea floor as the Sigsbee escarpment, an underwater cliff about 200 miles south of the US coastline. As well as presenting yet another drilling challenge, the allochthonous salt layer makes it very difficult to get seismic images of the formations below the salt. Seismic technology is advancing, but exploration below the salt remains challenging and risky.

4.4 *IOR in Onshore and Offshore Gulf of Mexico*

Onshore exploitation in the Gulf has steadily progressed towards development and maturation of fields located in the inboard petroleum province. Success in drilling and recovery operations can be attributed to ease of access to leases, well-developed commercial service sectors, extensive supply chains, and reliable procurement of utilities and materials. Economic viability is enhanced both by proximity to product-service markets and by accelerated project-to-project technology transfer. While application of advanced IOR methods continues to be a difficult and costly option for onshore reservoirs, many basic improvement strategies have been proven at the field-scale. Technical and business de-risking is invariably entwined in commercialization hence IOR depends on substantiating the process.

Offshore IOR activities in the Gulf have also moved forward but not nearly at the pace of land-based developments. Outboard IOR potential is governed by many subsurface and operational factors including complicated geologies, reservoir size, displacement mechanisms, drive energy, initial reservoir conditions, well depth, distance to nearest production facility, service and supply logistics, and fit-for-purpose technology. Deepwater IOR projects typically demand huge cost structures that fail to return a minimum acceptable profitability. Original-oil-in-place and more importantly, recoverable reserves is a key driver in outboard project feasibility. A large resource base is required to offset a huge development expense thereby reducing the unit capital cost of doing business in the offshore arena. On the operations side, a joint venture or tie-back to a host facility can achieve a similar reduction in unit cost. However, certain business alliances carry inherent risk such as in the event of host abandonment and forced cessation of satellite operations when alternate infrastructure does not exist.

Complex geologies and heterogeneous formations add to the difficulty of implementing an IOR process. Deepwater oil plays are affected by an extensive salt canopy and localized salt domes. The presence of salt, particularly salt canopies, limits the ability to image the reservoir using 3D seismic which is critical offshore where well spacing is large. Reservoirs commonly occur as a series of stacked sand bodies separated by long, non-productive intervals. Specialized well completions and conformance control are enabling technologies for improved oil recovery.

Deeper reservoir targets correspond to increased wellbore length which in turn translates to additional drilling costs associated with offshore rig rates. To achieve minimum well counts, extended reach and multi-lateral trajectories are cost saving options. Deep offshore plays have an IOR advantage over shallower onshore counterparts in that extra depth usually provides in-situ pressures exceeding the minimum miscibility pressure for gas injection.

Gas-based EOR techniques depend on a reliable and inexpensive supply of hydrocarbon gas, nitrogen, carbon dioxide, or a combination of these injectants. As produced gas may not meet own-use utilization rates for hydrocarbon flooding, a make-up stream from an outside source must be secured. Neighboring deepwater gas pools in the Gulf are an ideal choice for sourcing these IOR project needs. Potential benefits of gas deliverability from offshore fields would then

be shared between supplier and consumer with expected transmission savings compared to onshore supply alternatives. Depending on the suitability of hydrocarbon gas injection for individual reservoirs and the aggregate volume required by injection projects across the Gulf, the call for gas might well be a stimulus for both producing entities and undeveloped plays that would otherwise be stranded.

A summary of key differences between conducting IOR onshore versus offshore specific to the deepwater Gulf of Mexico are described in table xx.

Table 5: Comparison of onshore and offshore deepwater GoM IOR

Item	Onshore	Offshore GoM
Pressure	Normal / Low	Over-pressured / high
Reservoir Depth	Typically < 10,000 ft	Primarily > 15,000 ft
Well Spacing	Close (< 100's ft)	Wide (>1000's ft)
Well Cost	Typically < $10 million	> $50 million
Number of Wells	Not limited	Limited by platform and subsea infrastructure
CAPEX / OPEX	High	Significantly higher than onshore
Well Injection / Production Rates	Typically < 5000 bbl/d	High, much > 5000 bbl/d
Response Time	Typically < 6 months	Long, > 1 year
Pilot Testing	Easy to implement	Difficult and costly and often need to commit to full project
Availability of Injectant	Good but costly	Challenges to supply due to distance and cost

4.4.1 Recovery Technology: The Onshore-to-Offshore Transition

Extrapolating reservoir-based IOR technology from a proven onshore application to an offshore prospect should be straightforward given comparable subsurface conditions. Constancy in reservoir principle as premised in the field analog method suggests simple technology transfer. Development experience though, has not followed this line of reasoning as surface factors dominate almost every aspect of field conceptualization. In-situ processes are impacted as well at the operational interface. An escalated degree of difficulty coupled with sometimes unprecedented harsh reservoir conditions critically alter how the recovery scenario will unfold and these differences become the basis for adapting an onshore depletion model for offshore exploitation.

An onshore example used for illustration is the Weeks Island Field located in New Iberia Parish, Louisiana (Johnston, 1988; Holtz et al., 2008). The Weeks Island oil play is structurally complex and trapping mechanisms are associated with salt tectonics. A gravity-stable CO2 pilot test (1978-1980) was carried out on Reservoir B, a Miocene-age sandstone. The B sand is at a depth of 12,800 feet. Like most Gulf Coast sandstone reservoirs, the producing formation is underlain by a strong natural water drive. Net pay is 21 feet. Initial reservoir pressure and temperature are 6,013 psi and 225 °F, respectively. Crude oil is of a high quality with an API

gravity of 33° and 0.6 cp viscosity. As the minimum miscibility pressure for CO2 is 3,528 psi, oil production was obtained by miscible displacement. Incremental recovery from injecting CO2 gas amounted to 15% of the OOIP.

Similar performance can be expected from CO2-EOR offshore projects. The present state of gas injection and CO2 reject facilities is amenable to deepwater operations provided infrastructure is customized to the offshore environment. Availability of equipment is not the major issue rather it is the manner in which CO2 is supplied to the project. In the Weeks Island trial, carbon dioxide was sourced directly from an ammonia plant. Paleogene fields, on the other hand, would require a subsea CO2 pipeline system of 150 miles or more to transport the injectant from Gulf Coast suppliers to the offshore facility. Despite field-verified improvements from CO2 injection over other gas-based EOR methods, deliverability issues prevent serious consideration of carbon dioxide flooding in offshore reservoirs.

4.4.2 Production Technology: The Onshore-to-Offshore Transition

Production equipment, reservoir treatments, and drilling completion technology play an important role in the success of any development project. Whether onshore or offshore, production-oriented applications and procedures are vital to primary depletion and enable IOR processes which may extend the life of a producing property.

Horizontal well technology is widely acknowledged as a production-based IOR process. Productivity gain from horizontal wells is demonstrated at the Olla Field, central Louisiana (Hansen et al., 1992). Located in La Salle Parish, Olla has fourteen producing zones ranging from 3 to 120 feet in thickness. The target formation is the Cruse sand, a shallow, medium to fine grained Wilcox sandstone at 2,100 feet. Initial reservoir pressure is 1,000 psi. Permeability averages 525 md and porosities are in the 27-38% range. Relative performance indicated an improvement of 500% in the productivity and actual production for a horizontal well over an adjacent vertical well.

Drilling and completion practices for inboard horizontal wells have been adapted for outboard reservoirs and effectively repeated in the deepwater Gulf at the Europa and Ram Powell fields (Colodette et al., 2008). In the Campos Basin, offshore Brazil, much advancement in drilling complex well geometries have narrowed the gap between onshore and offshore technology although operability in high pressure-high temperature conditions is still problematic.

5 Overview of Geology

5.1 *Gulf of Mexico Morphology and Structure*

5.1.1 Geomorphology, Gulf of Mexico Basin

The Gulf of Mexico is connected to the Atlantic Ocean through the narrow Florida Straits and to the Caribbean Sea by the Yucatan Channel. Away from these two silled oceanic connections, it is a nearly land-locked basin (Figure 9). It contains three wide continental shelves, West Florida Shelf, Texas-Louisiana Shelf and the Campeche Platform and a narrow Mexican Shelf at the west side of the Gulf. The deep central part of the Gulf is called the Sigsbee Deep or Sigsbee Abyssal Plain.

The Sigsbee Abyssal Plain is separated from the Texas-Louisiana Shelf by the broad Texas-Louisiana Slope, underlain by salt structures and affected by downslope salt movement. The bathymetry of this slope is marked by numerous salt mini-basins, salt canopies and salt diapirs. The southern edge of the Texas-Louisiana Slope is the Sigsbee scarp, a prominent submarine cliff that trends roughly east-west and then turns to the northeast towards the Mississippi delta. In addition to the distinctive Texas-Louisiana Slope, the large Mississippi Fan dominates the central Gulf west of the West Florida Shelf.

Several submarine canyons incise the Texas-Louisiana Slope and West Florida Shelf. From east to west they are: De Soto Canyon, Mississippi Canyon, Keathley Canyon and Alaminos Canyon. Smaller canyons include Green Canyon and Bryant Canyon.

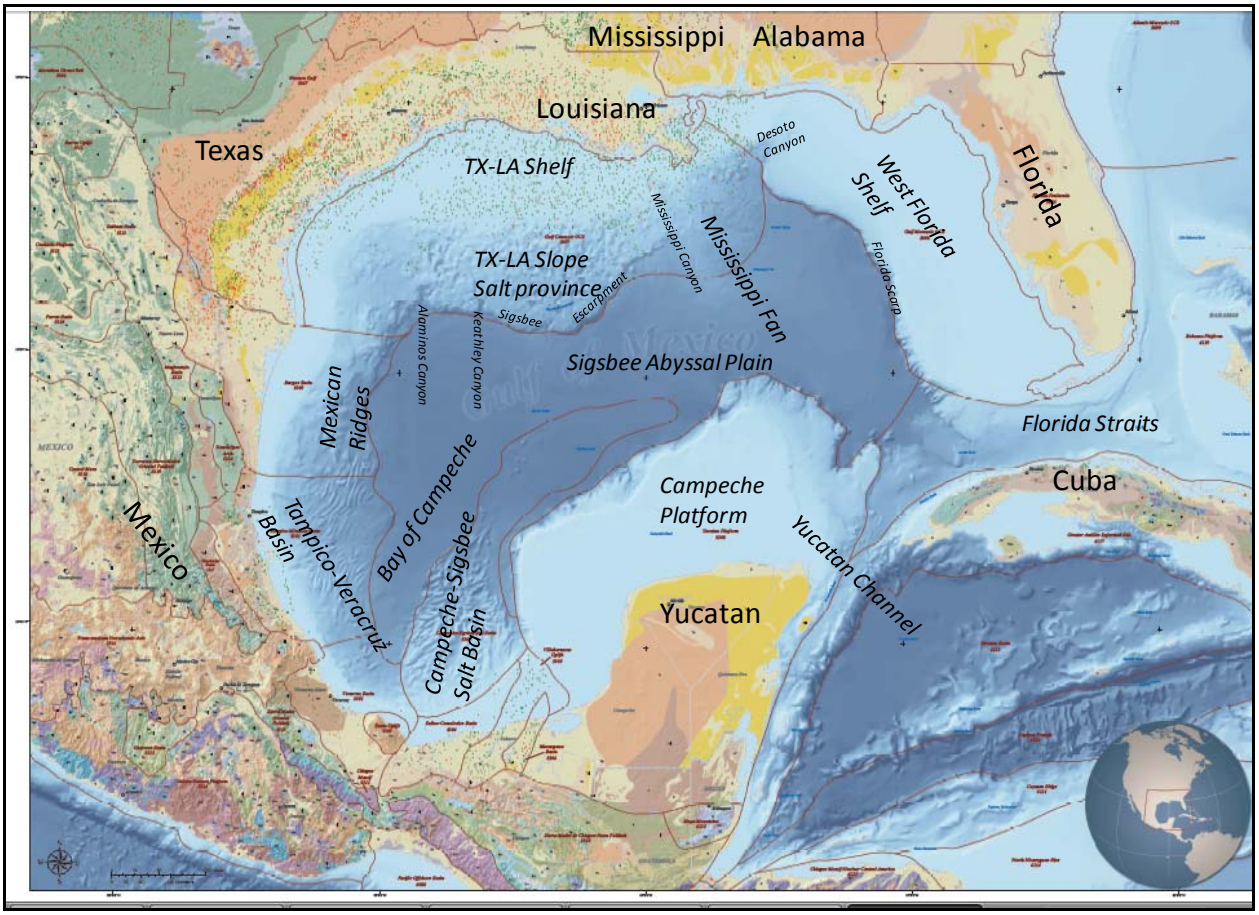


Figure 9: Major geomorphic features of the Gulf of Mexico (map from USGS with annotations)

5.1.2 Formation of the Gulf of Mexico Basin

The early tectonic history of the Gulf of Mexico basin is difficult to determine due to several factors:

- Early rifting involved several continental blocks
- High northern Gulf sedimentation rates buried and obscured early structures, and
- Extensive salt tectonics distorts and obscures seismic reflection data.

Nearly all recent models involve plate tectonics, with the Yucatán block having a prominent role. The model proposed by Pindell (1993), (Figure 10) shows early rifting between North America and Europe, and between North America and South America, resulting in separation of the Yucatán Block from North America. Counter-clockwise rotation of this block results in formation of oceanic crust that underlies the deep central Gulf of Mexico.

Based on crustal models and seismic refraction studies, oceanic crust is interpreted beneath the Texas/Louisiana slope and Sigsbee Abyssal Plain. This central basin oceanic crust trend swings southward into the Bay of Campeche and trends parallel to the Yucatán slope. The formation of oceanic crust resulted when the Yucatán Block rotated counter-clockwise away from North America during early rifting.

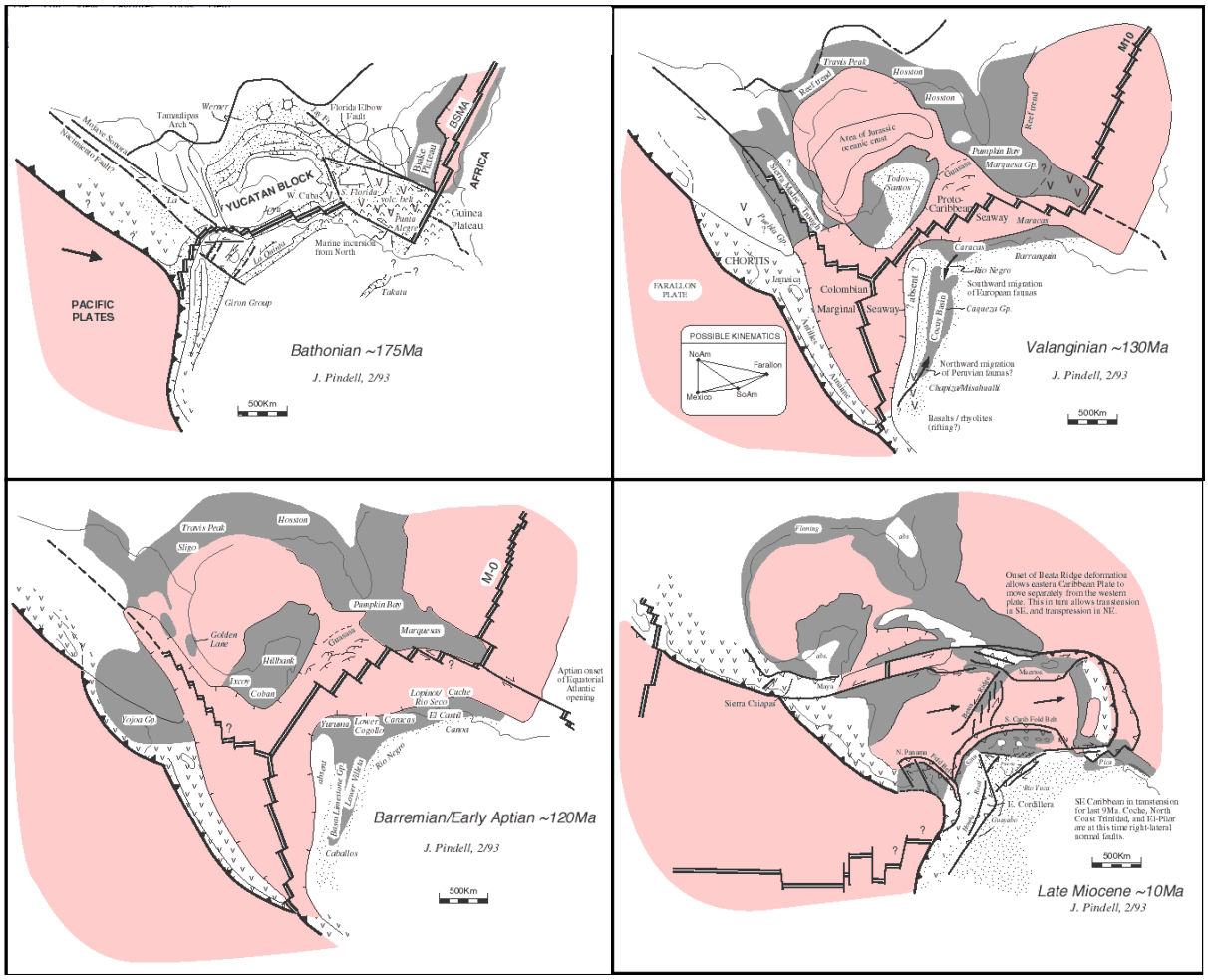


Figure 10: Origin of the Gulf of Mexico and Caribbean (Pindell, 1993)

5.1.3 Gulf of Mexico Structure and Salt Techtonics

The structural and depositional setting of the deepwater Gulf of Mexico is dominated by salt tectonics. The movement of salt controls the location, geometry and timing of slope basins, and thick salt canopies have a significant impact on seismic resolution of sub-salt plays (Figure 11).

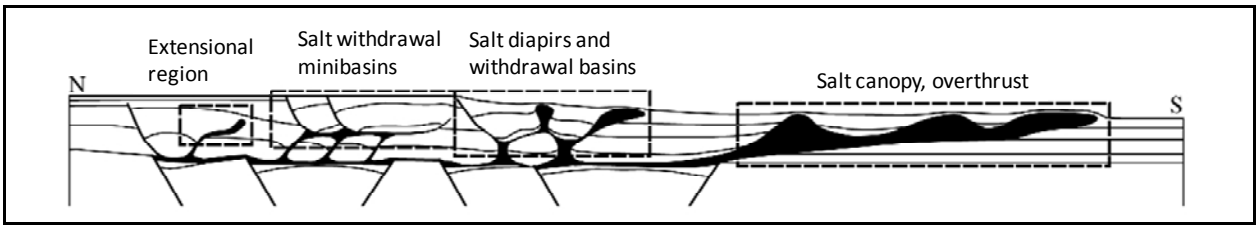


Figure 11: Salt structural features, summary (Rowan, 1999)

5.1.3.1 *Salt Movements: Overview*

Salt is mobile when differentially loaded by sediment. This loading causes the salt to flow away from the greatest sedimentary load and upward into thinner sedimentary sections. The upward

motion of the salt is due to two factors: 1. Salt is a weak rock with fluid properties similar to glacial ice, and 2. Salt is less dense than most compacted sediments.

The lateral and upward motion of the salt has several consequences. Areas where the salt withdraws become sedimentary basins. When enough salt withdraws, the sedimentary rocks above the salt meet the sedimentary rocks below and a salt weld results (Figure 12). Once the rocks are “welded”, the salt-withdrawal subsidence ceases. The upward motion of the salt results in circular or tabular diapirs. These are common on the northern Gulf of Mexico shelf and upper slope where they control much of the structures where oil and gas are found. Further down slope, the moving salt can coalesce into a thick, over-thrust salt canopy. The seaward limit of this remobilized salt canopy is the Sigsbee escarpment (Figure 13).

The salt canopies act like an over-thrust sheet and can be composed of individual salt sheets. These sheets can stack up to thicknesses of thousands of feet. At Tiber field, the salt canopy is up to 15,000 ft thick. This thick salt canopy is moving and may contain over-pressured shale bodies. The combination of mobile salt and these over-pressured shale intervals create drilling hazards in deep water.

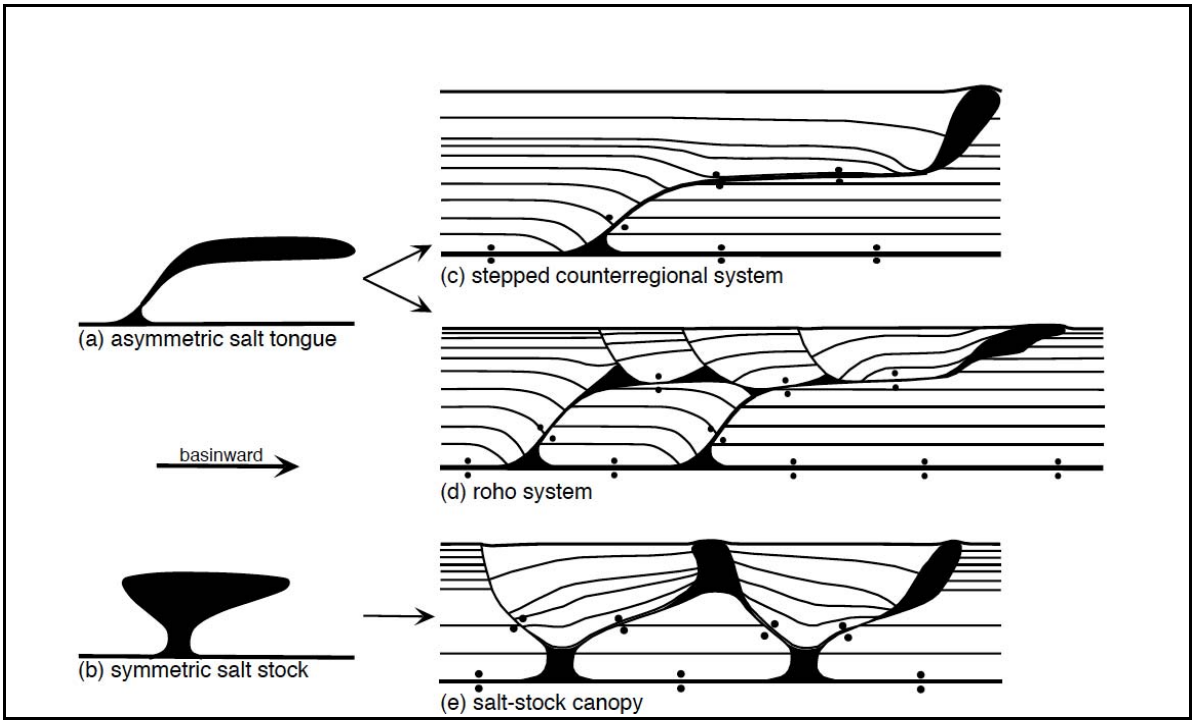


Figure 12: Salt structural geometries. Salt shown in black, welds shown by dots (Rowan, 2001)

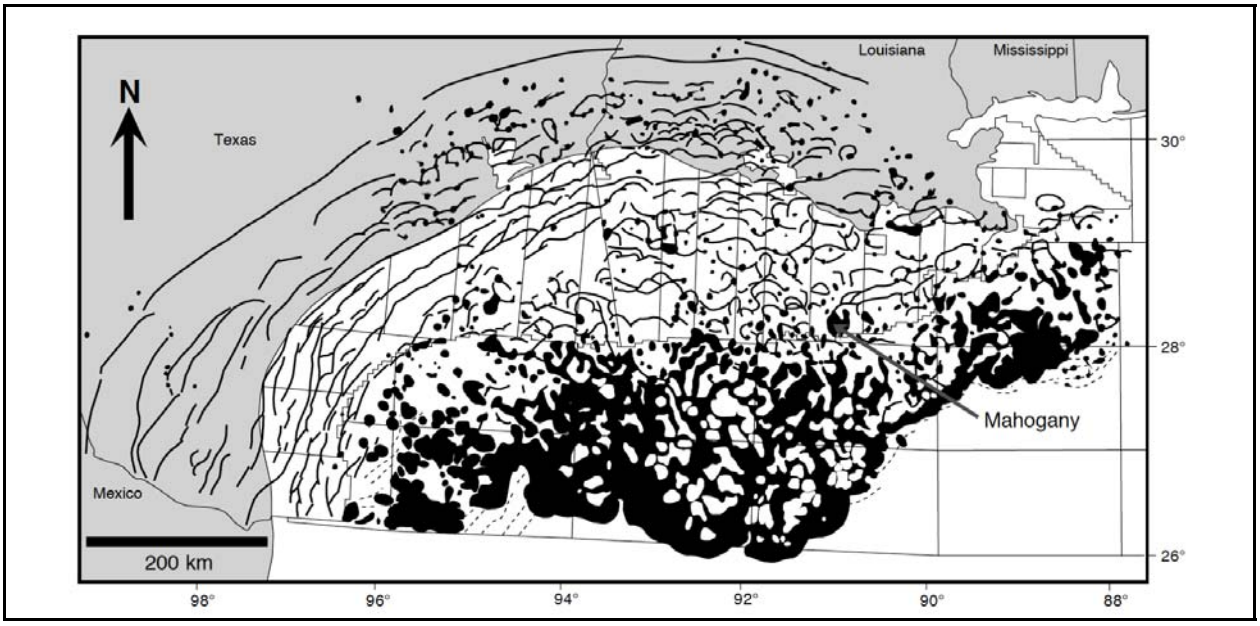


Figure 13: Salt distribution, northern Gulf of Mexico, with salt canopies and individual diapirs (Rowan, 2001)

5.1.3.2 ***Salt Movements and Structural Styles: Autochthonous and Allochthonous Salt***

The structural style of the mobile salt results in a classification into two types of salt masses. Autochthonous salt is where the salt is in the original stratigraphic position and rests on older sedimentary rocks. Allochthonous salt is overthrust and rests on younger rocks. In areas of allochthonous salt, there can be two levels of salt: the shallow overthrust allochthonous salt and the older autochthonous salt. The allochthonous salt region is generally the middle to lower northern Gulf of Mexico slope.

A series of seismic profiles illustrate the structural styles associated with salt movement and withdrawal. In updip regions, there can be normal growth faults associated with salt withdrawal and formation of salt welds (Figure 14). At the same time, the downdip portion of a moving sedimentary block on salt can have high-angle reverse faults (Figure 15). Near the base of slope, salt-cored anticlines appear, many with an array of normal crestal faults (Figure 16). In the western portion of the northern Gulf of Mexico, tectonic compression during the middle Tertiary has results in the formation of compression folds bounded by high-angle reverse faults in the Alaminos Canyon area (Figure 17). The orientation of these faults differs from the downslope motion of other salt-cored compressive structures. The Alaminos Canyon structures generally trend NE-SW and follow regional compression, whereas most downslope compressive structures trend ENE-WSW or even EW.

A series of block diagrams illustrates the variety of structure possible in several tectonic settings (Figure 18). Figure 18a shows an extensional system where salt withdrawal has resulted in growth-fault bounded basins. Figure 18b shows rotated blocks over a salt detachment with extensional faults updip from reverse faults downdip. Figure 18c shows major withdrawal basins and intervening diapiric structures. Figure 18d shows an overthrust region with a salt canopy. In addition, small minibasins occur on top of the salt canopy.

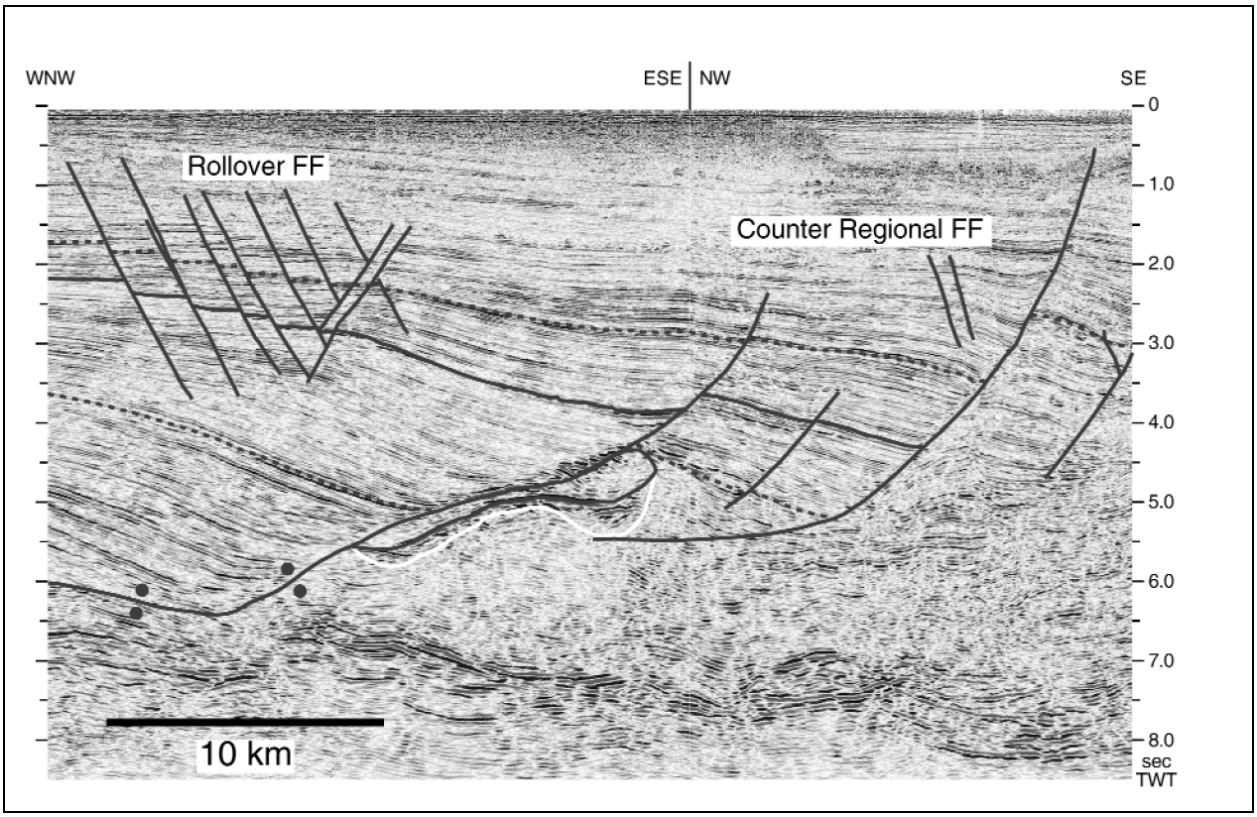


Figure 14: Extensional faults and salt weld, northern Gulf of Mexico (Rowan, 2001)

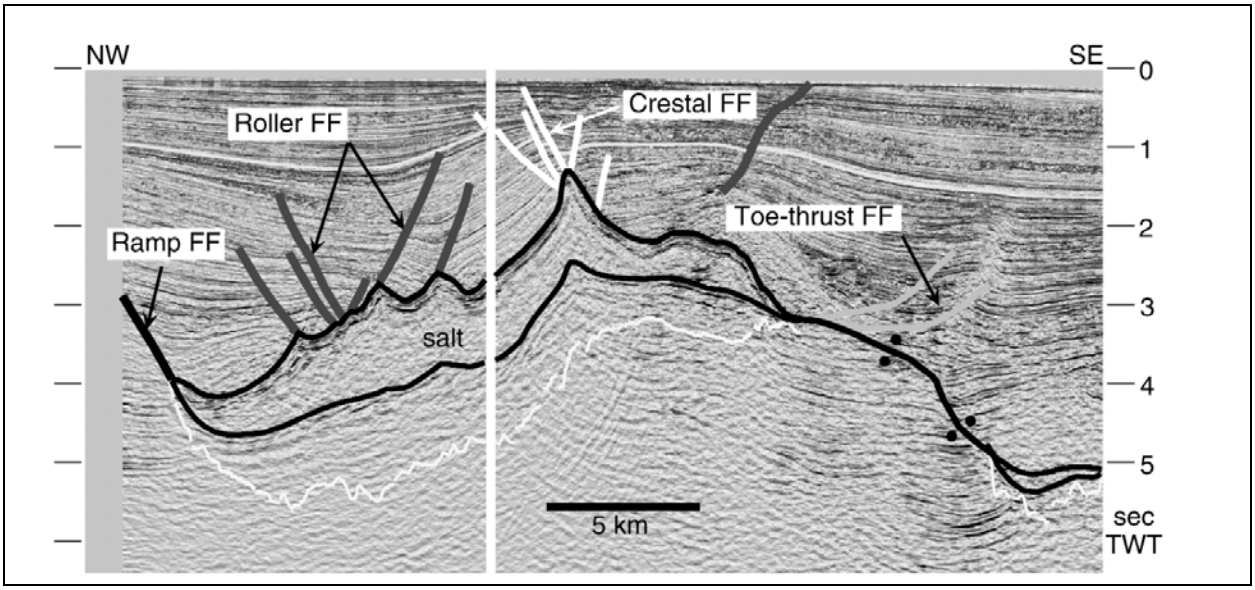


Figure 15: Normal and reverse faults associated with salt movement and withdrawal (Rowan, 1999)

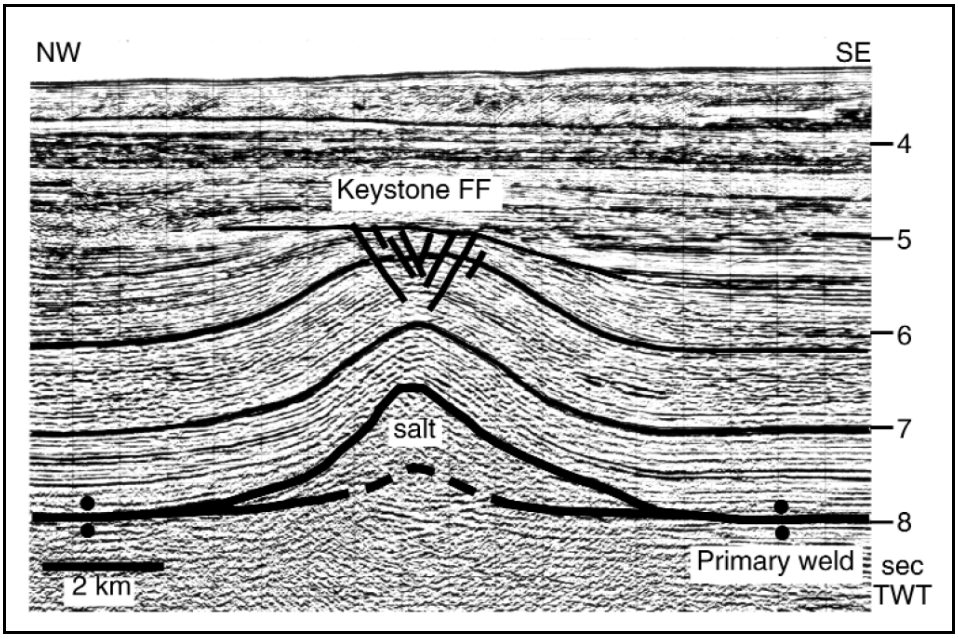


Figure 16: Base of slope compressional anticline over salt remnant (Rowan, 1999)

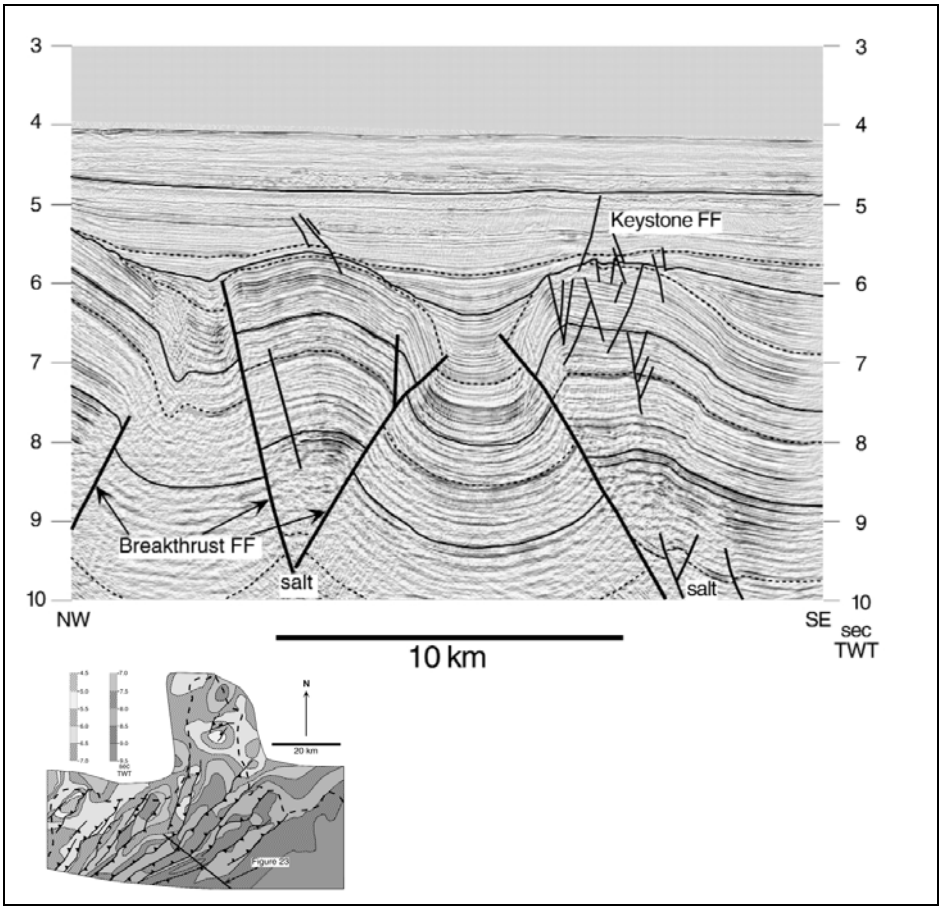


Figure 17: Alaminos Canyon compressional folds and reverse faults (Rowan, 1999)

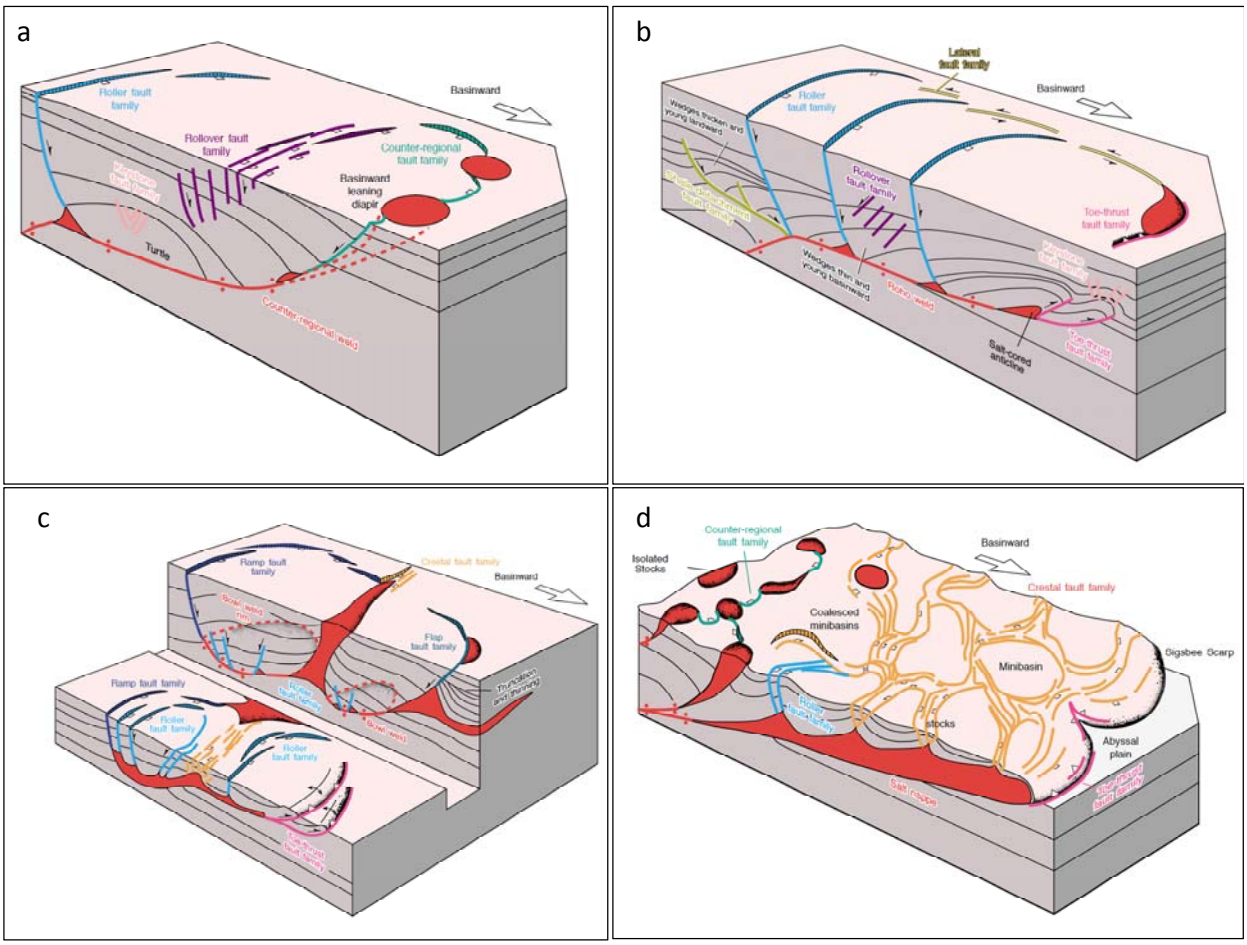


Figure 18: Block diagrams illustrating different salt-deformation structural styles (Rowan, 1999)

5.1.3.3 *Formation of Minibasins*

The movement and withdrawal of salt results in the formation of slope basins, referred to as mini-basins in the northern Gulf of Mexico. These basins affect the Neogene stratigraphic section more than the Paleogene.

Figure 19 illustrates the development of the Mahogany Salt Body (Rowan, et al., 2001) and associated minibasins. This example is typical of many mid and upper slope basins. The complex geologic history starts with early subsidence due to salt withdrawal. One basin is translated laterally as the underlying salt moves and then is fixed in place as a weld develops at the base of the minibasin. A top view of some of these minibasins is shown in Figure 20.

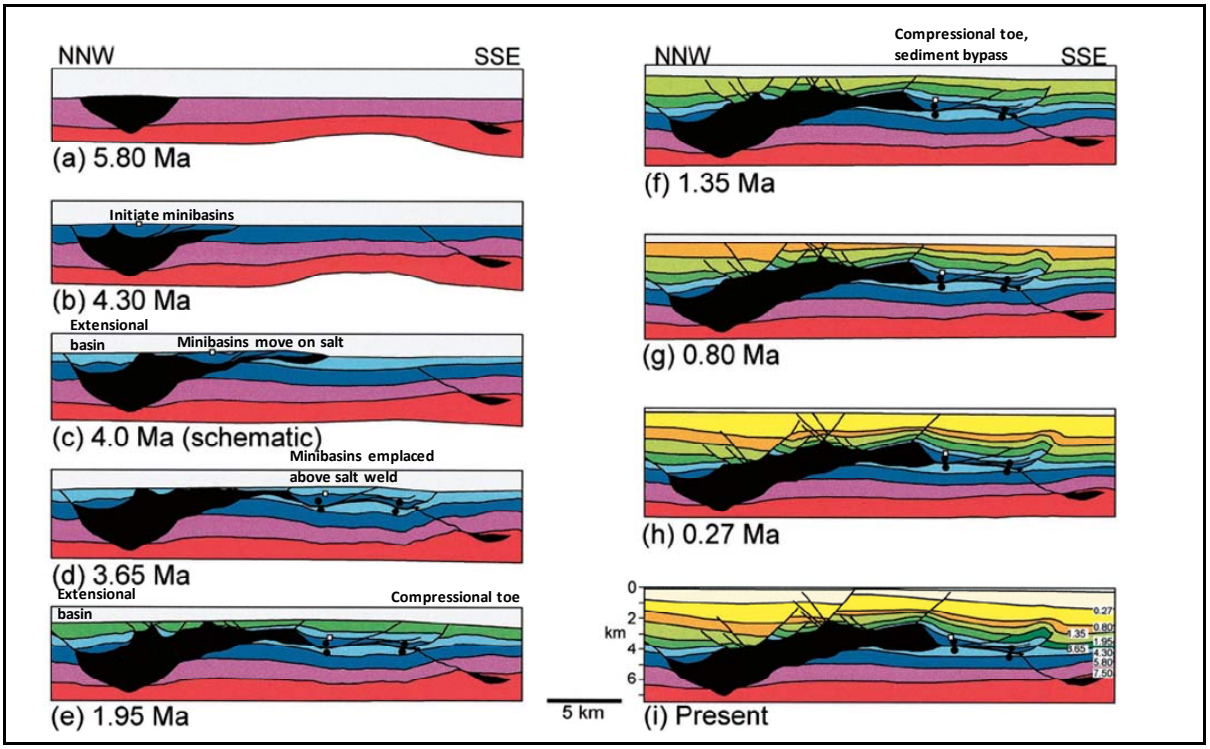


Figure 19: Mahogany Salt Tongue and associated minibasin history (Rowan, 2001)

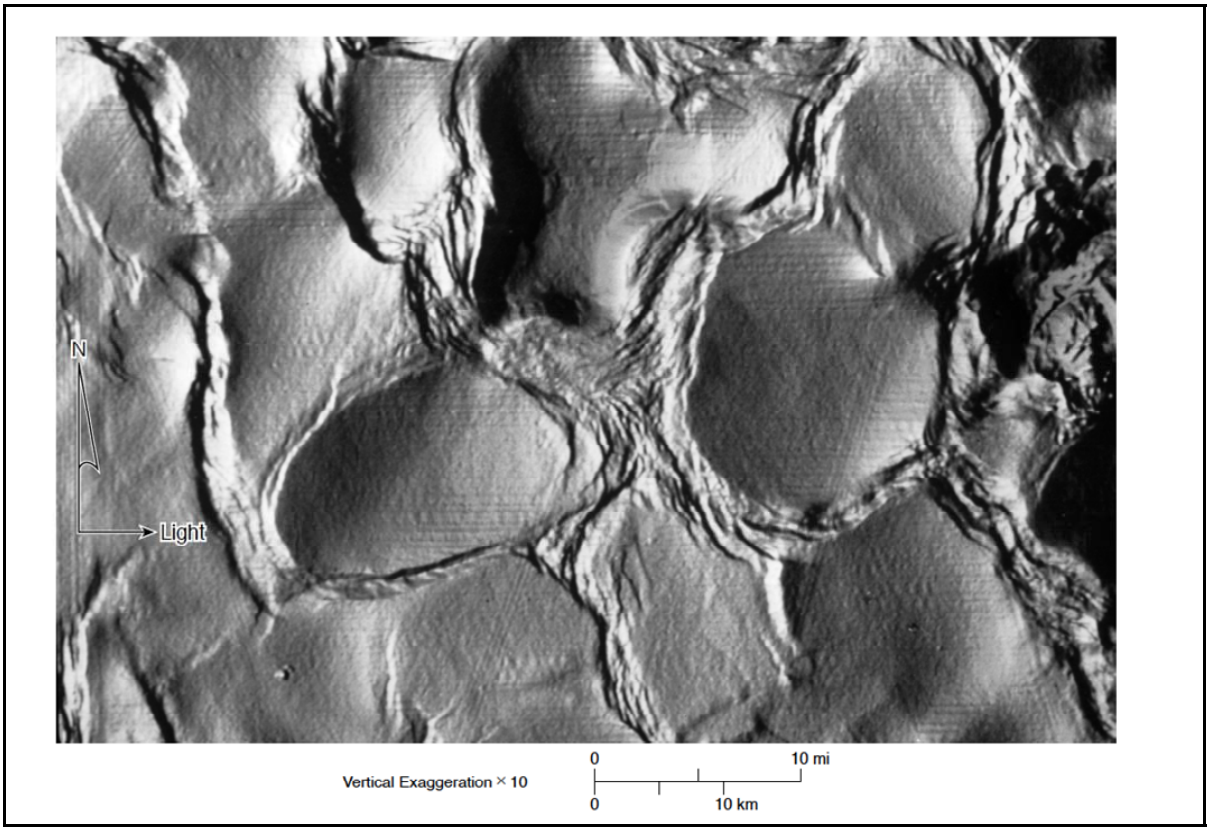


Figure 20: Example of mid-slope minibasins, northern Gulf of Mexico (Rowan, 1999)

5.1.4 Salt Canopies, Subsalt Structure and Sigsbee Scarp Play

A significant part of understanding Paleogene reservoirs in the deepwater Gulf of Mexico is based on knowledge of the salt canopies and their impact on deposition and diagenetic history. The salt canopies form in an area extending from mid-slope to the Sigsbee escarpment at the base of slope. From a feeder stock originating in the deep autochthonous salt, individual canopies spread laterally extending over the base of slope (Figure 21). Each canopy can be composed of one or more individual salt thrust sheets and total thickness of the canopies can exceed 20,000 feet.

The long seismic profile shown in Figure 22 shows that a large canopy in the western Gulf of Mexico starts near Red Hawk field and extends southward past Jack and St. Malo fields. Maximum thickness here is about 5,000 ft and the canopy thins as it approaches the Sigsbee escarpment. A seismic profile over Jack field (Figure 23) shows that it is mostly covered by thick salt, but that the southern edge of salt occurs nearby and part of the structure is uncovered.

The thick salt acts like a thermal-conductive blanket on the underlying sedimentary rocks. In some cases, this thick blanket of salt can conduct heat away from the reservoir rocks and result in formation temperatures that are lower than would be expected for a particular depth.

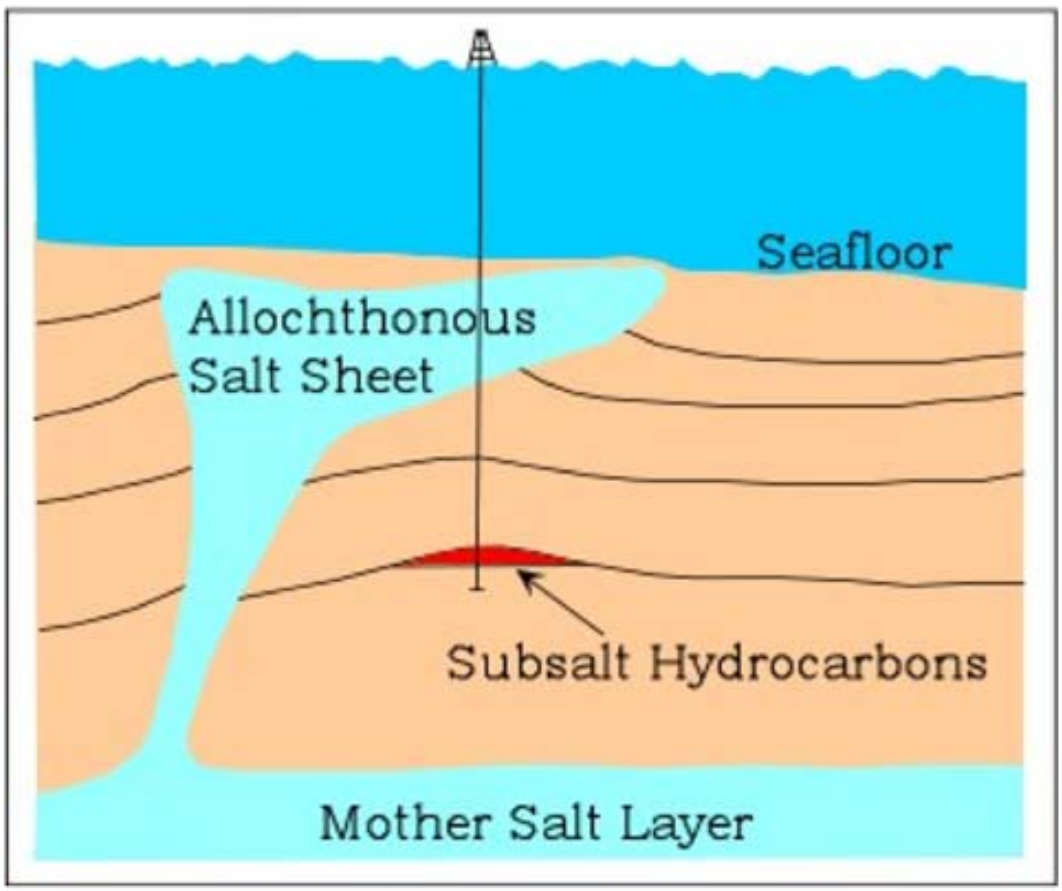


Figure 21: Conceptual salt sheet canopy and underlying hydrocarbon accumulations (MMS)

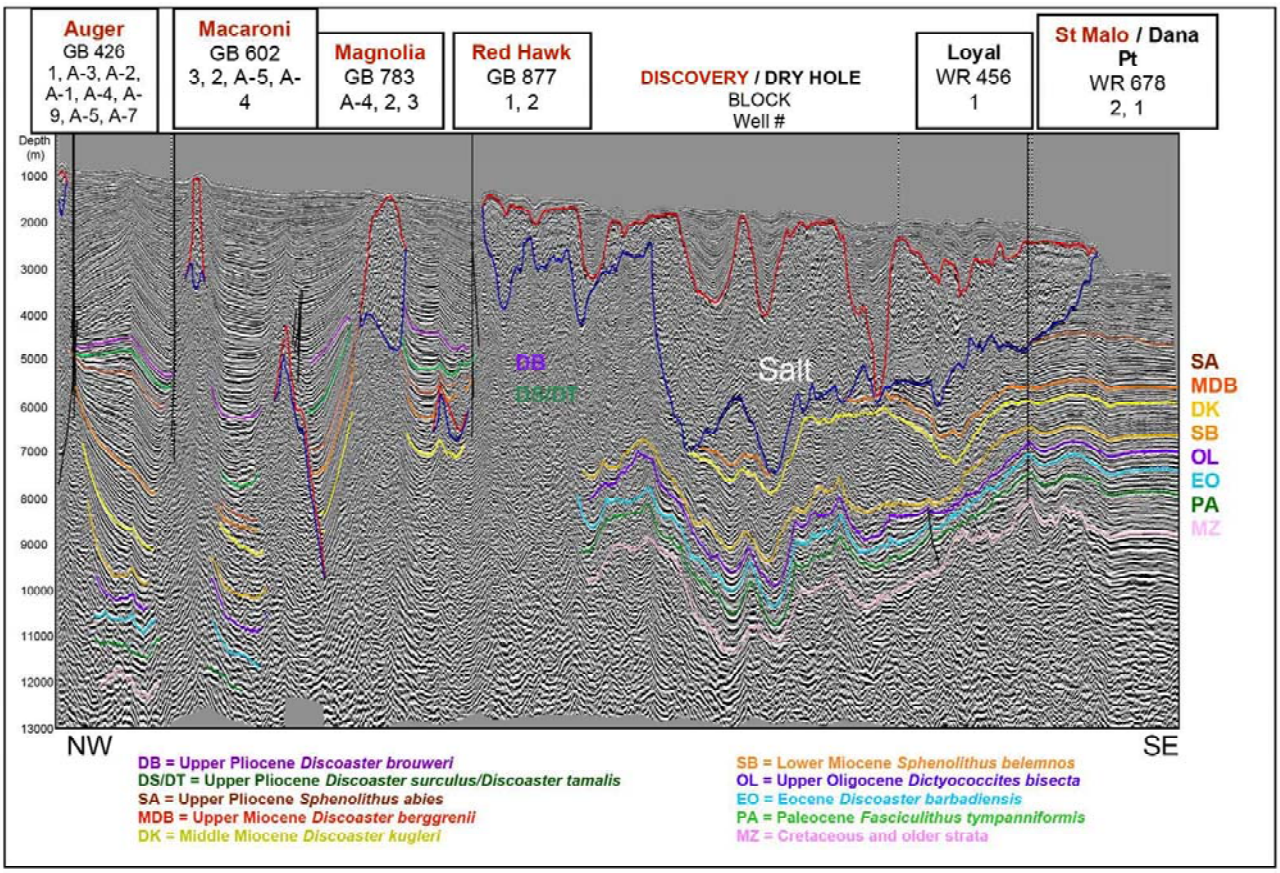


Figure 22: Regional seismic profile showing salt canopy and major hydrocarbon discoveries (Chowdury and Borton, 2007)

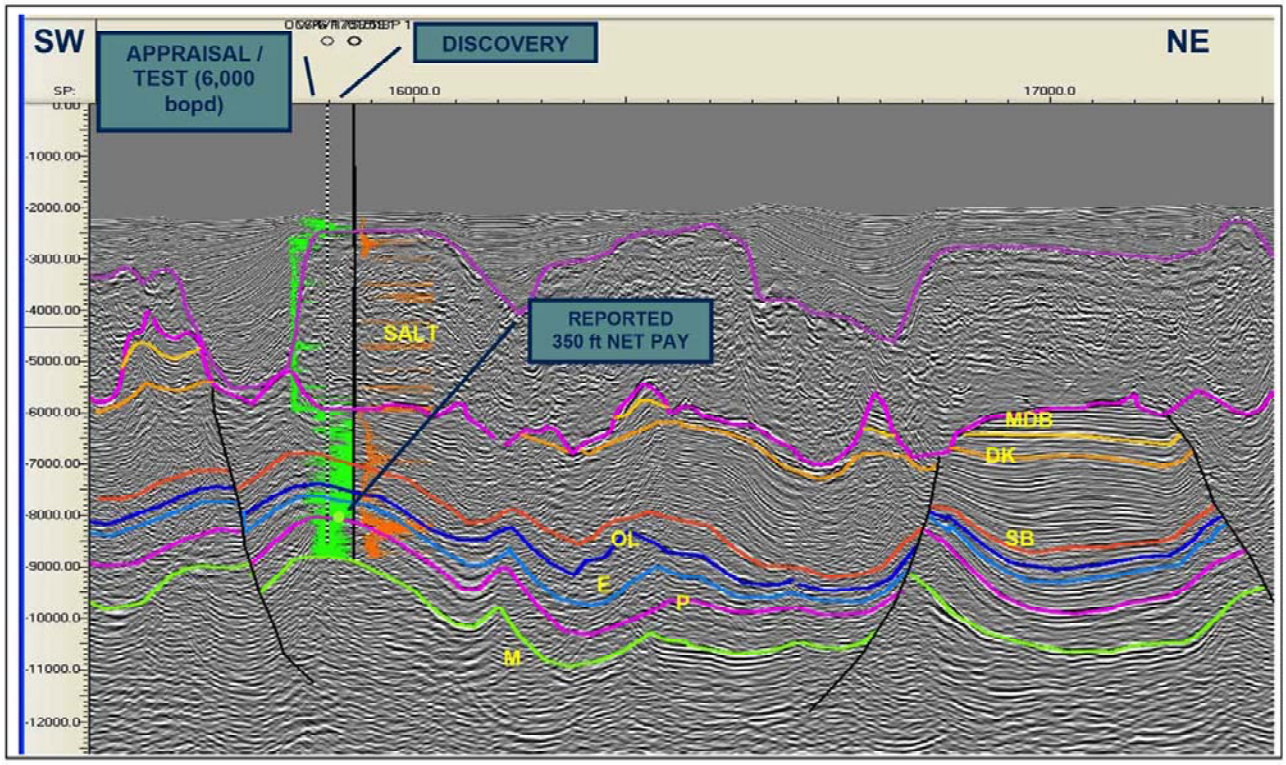


Figure 23: Thick salt canopy at the Paleogene Jack discovery (Chowdury and Borton, 2007)

5.2 *Gulf of Mexico Stratigraphy and Deposition*

5.2.1 Gulf of Mexico Stratigraphy Summary

The stratigraphy of the deepwater Gulf of Mexico can be divided into three main groups: Neogene, Paleogene and Mesozoic (Figure 24). Of these three divisions, most oil and gas have been discovered in the Neogene. This interval normally comprises the Miocene and Pliocene but for this report the Pleistocene has been added. There are a few hydrocarbon fields, e.g. Bass Lite, in the Pleistocene and since the same depositional and structural setting apply to these fields as to the regular Neogene, it seems reasonable to include them with the Neogene.

The Paleogene includes the Oligocene, Eocene and Paleocene and consists mostly of sandstone and shale. Reservoir intervals include the Frio (Oligocene) in the Alaminos Canyon area, the Upper Wilcox (Eocene) in the same area and the Lower Wilcox throughout the Alaminos Canyon, Keathley Canyon and Walker Ridge blocks. The development of these reservoirs is in a much less mature state than the Neogene reservoirs.

The Mesozoic section includes the Cretaceous and Jurassic. These rocks comprise the main source rock intervals (Jurassic and mid-Cretaceous) as well as the salt (Jurassic) that controls the structural style of the Gulf of Mexico. There have also been a few hydrocarbon discoveries in the Mesozoic, namely Shiloh field in the northeastern Gulf of Mexico.

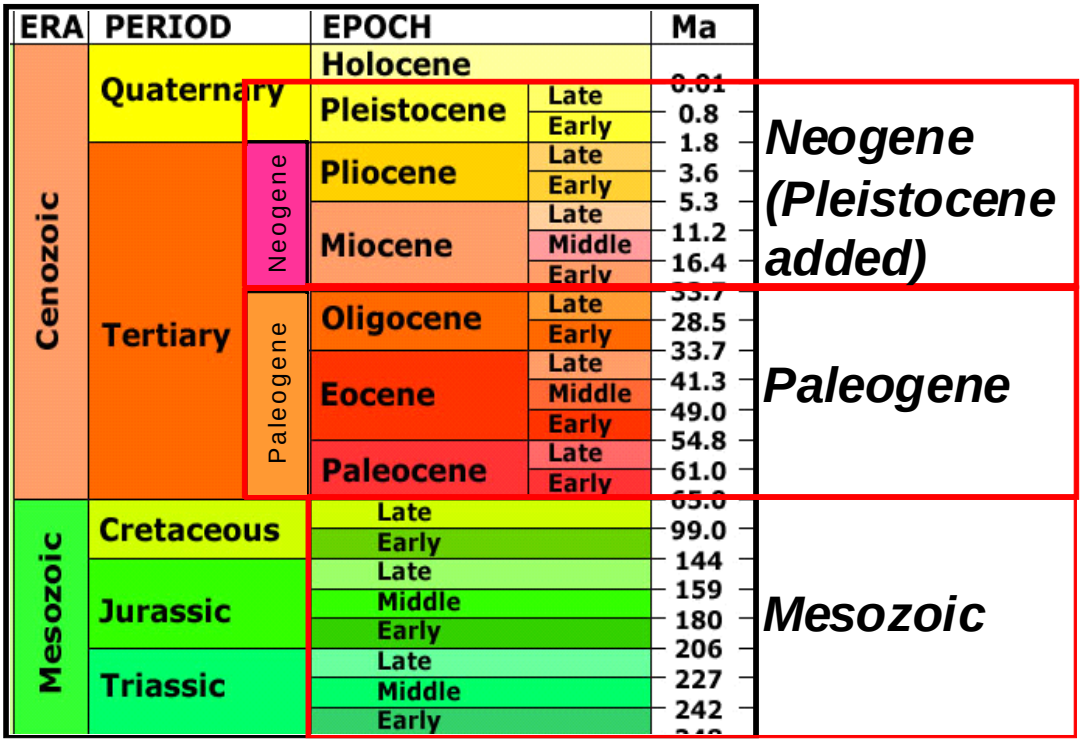


Figure 24: Major stratigraphic divisions, Gulf of Mexico

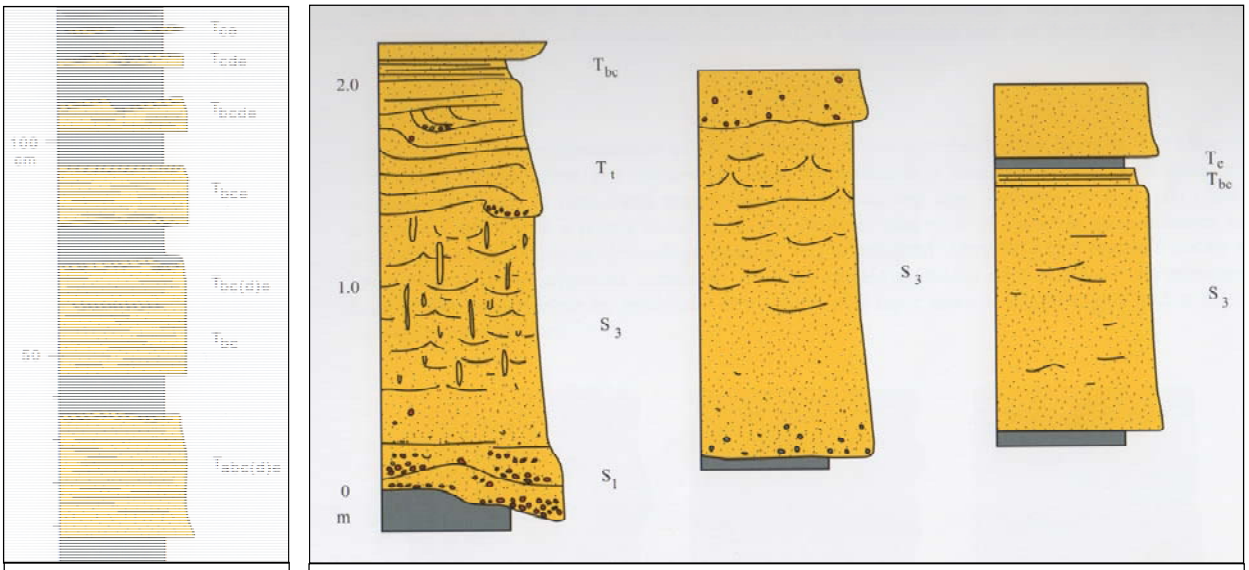
5.2.2 Depositional Models

5.2.2.1 *Turbidite Elements*

Deepwater depositional processes mostly consist of density-driven, downslope processes. These include sediment-gravity flows, including turbidites, and mass transport processes. For the purposes of this report, sediment-gravity flows are referred to as turbidites. Mass transport processes can form reservoirs but these are unusual and not considered in this overview report.

Turbidites can be classified as low-density or high-density and this refers to the density of the turbid fluid that transports sediment into deep water (Figure 25). Low-density flows have a muddy matrix and form turbidites having a classical appearance with typical Bouma sequences of sedimentary structures. High-density flows are sand rich and deposited very rapidly. The rapid burial and trapping of interstitial water results in dewatering structures, such as dish structures and vertical dewatering pipes. Due to the high energy of these flows, gravels or large clay clasts are often transported as well as sand.

The energy transporting sediment by these flows is expressed in reservoir properties. Low-density flows are generally finer grained; in addition, the transporting flow us mud-rich. Therefore, the reservoir will contain finer-grained sand and silt with a clay matrix. High-density flows will be coarser grained and cleaner, with little or no clay matrix. These types of flows make the best hydrocarbon reservoirs.



Low-density Turbidites:
Levee or distal sheet/ Lobe facies

High-density turbidites, channels, proximal sheets and lobes

Figure 25: Turbidite classification: low-density and high-density turbidites (Lowe, 2004)

5.2.2.2 *Depositional Environments*

The turbidite elements occur in specific depositional environments and similar flows can occur in different environments. For purposes of this report, deepwater environments are kept simple and consist of channel/levee complexes, proximal lobes and sheets, distal lobes and sheets and mass-transport complexes (Figure 26).

In general, levee and distal deposits consist of low-density flows and proximal environments and channels will consist of high-density flows. The predominance of high-density type flows in proximal sheet, lobe and channel facies results in better initial reservoir properties in these environments.

Channel/levee complexes consist of paired levees with interbedded sandstone and shale flanking channel facies (Figure 27). The channels can consist of bypass channels that are shale-filled, or the channels can be sand filled at the same time the levees are constructed.

Depositional lobes and sheets can grade from one to the other; the lobes are often the proximal expression of basin-floor sheet sands (Figure 28). Lobes may have a thickening-upward depositional pattern whereas sheet sands are often thick, blocky and clean sand accumulations.

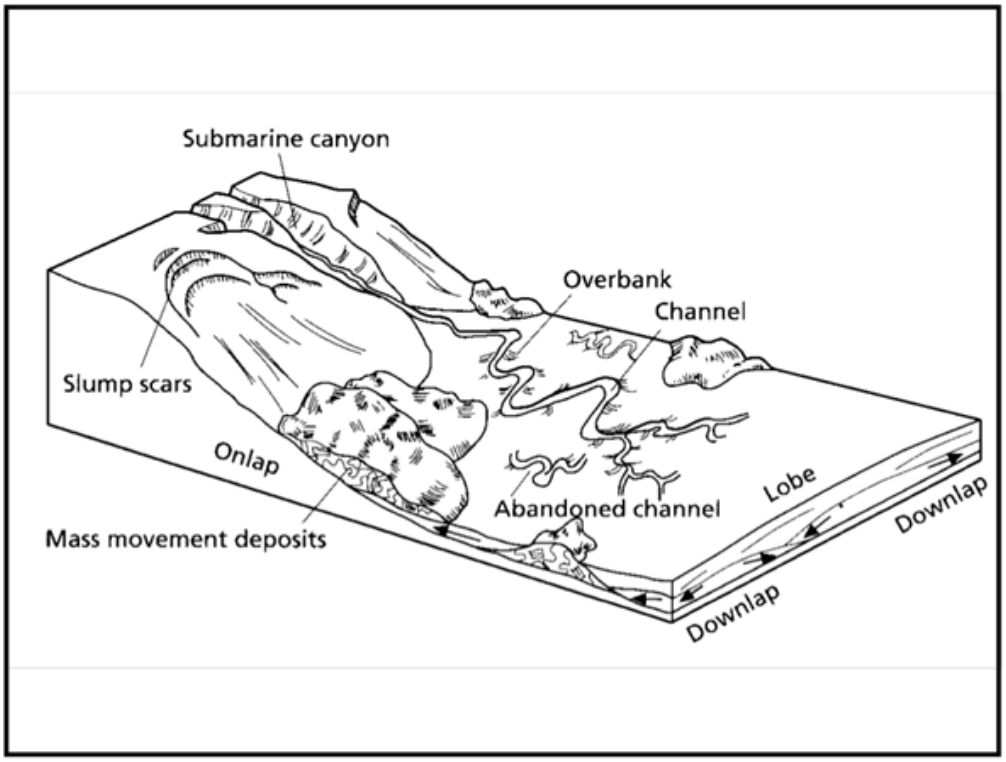


Figure 26: Depositional elements, deepwater Gulf of Mexico

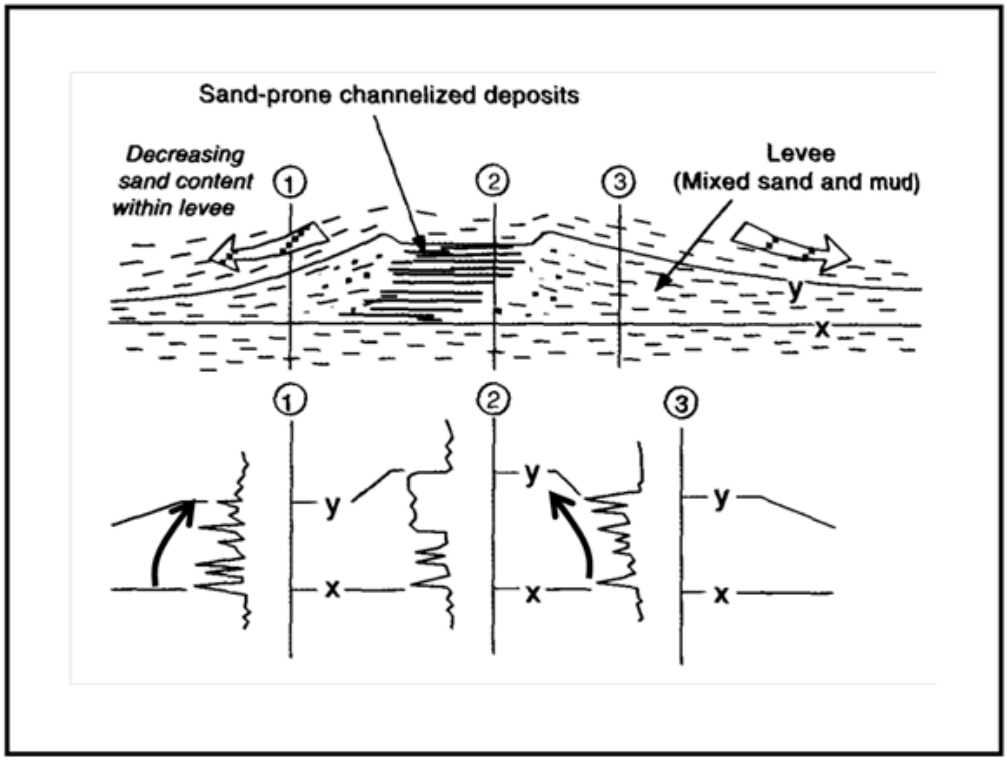
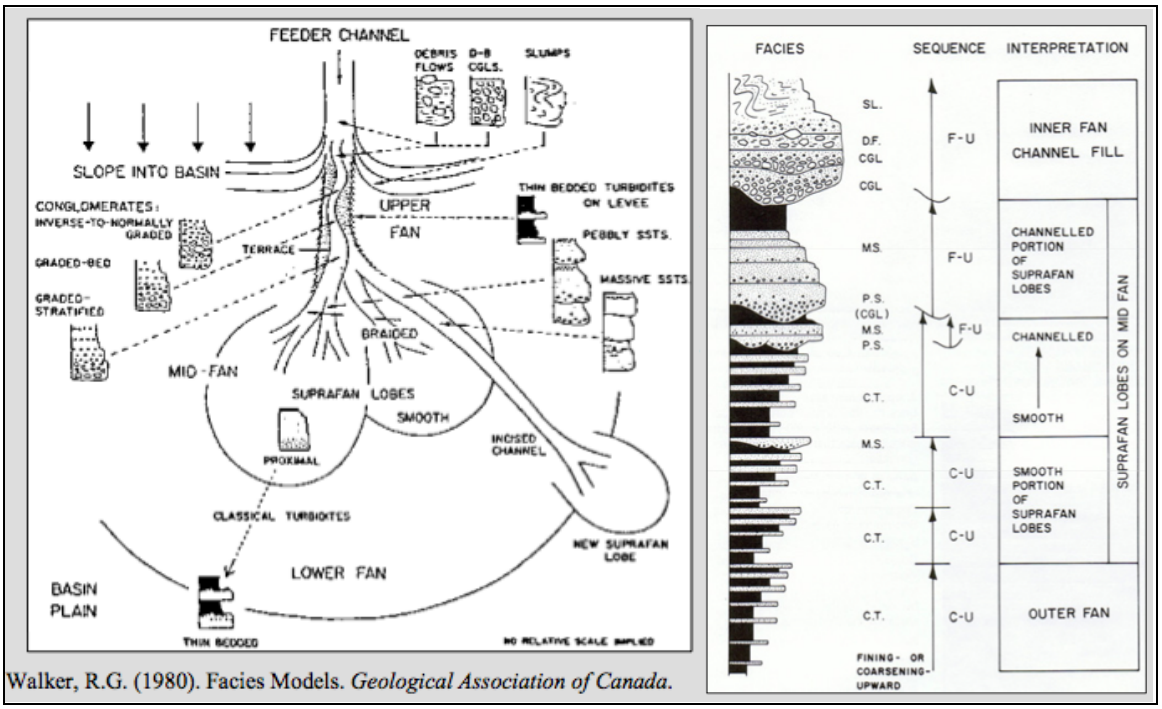


Figure 27: Channel/levee depositional model



Walker, R.G. (1980). Facies Models. *Geological Association of Canada.*

Figure 28: Depositional lobes and sheets on a simple submarine fan model (Walker, 1980)

5.2.2.3 ***Depositional Systems***

Depositional systems are the final classification of deposits. The geometry and location of deposition of these systems is controlled by salt deformation effects on local structures on the slope (Figure 29). At the base of slope, large submarine fan systems occur that are dominated by thick, blocky sheet sands (Figure 30). Slope minibasins are filled by smaller fans as well as channel/levee complexes. Here, sheet and lobe deposits may be more localized than base of slope systems (Figure 30). Shaley levee facies may also occur in late-stage minibasin fill.

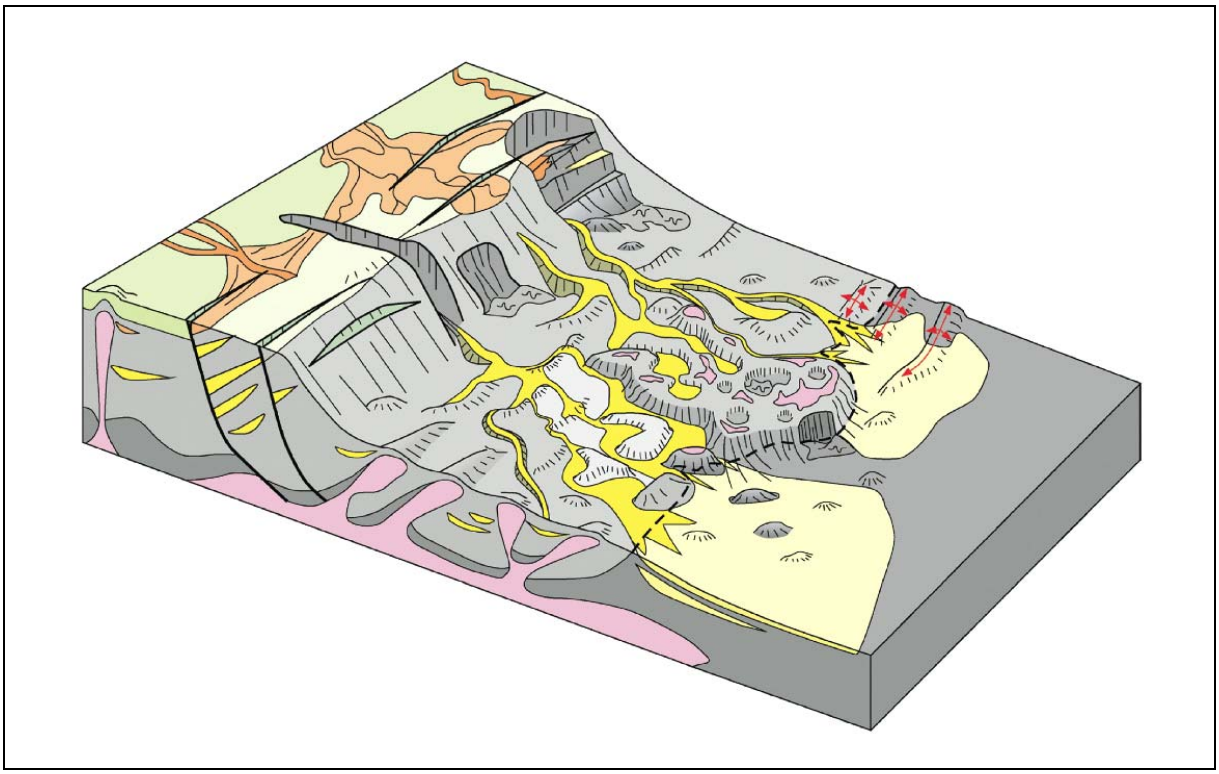


Figure 29: Depositional model for a complex slope setting. Sand deposition shown in yellow (Mayall, et al., 2010)

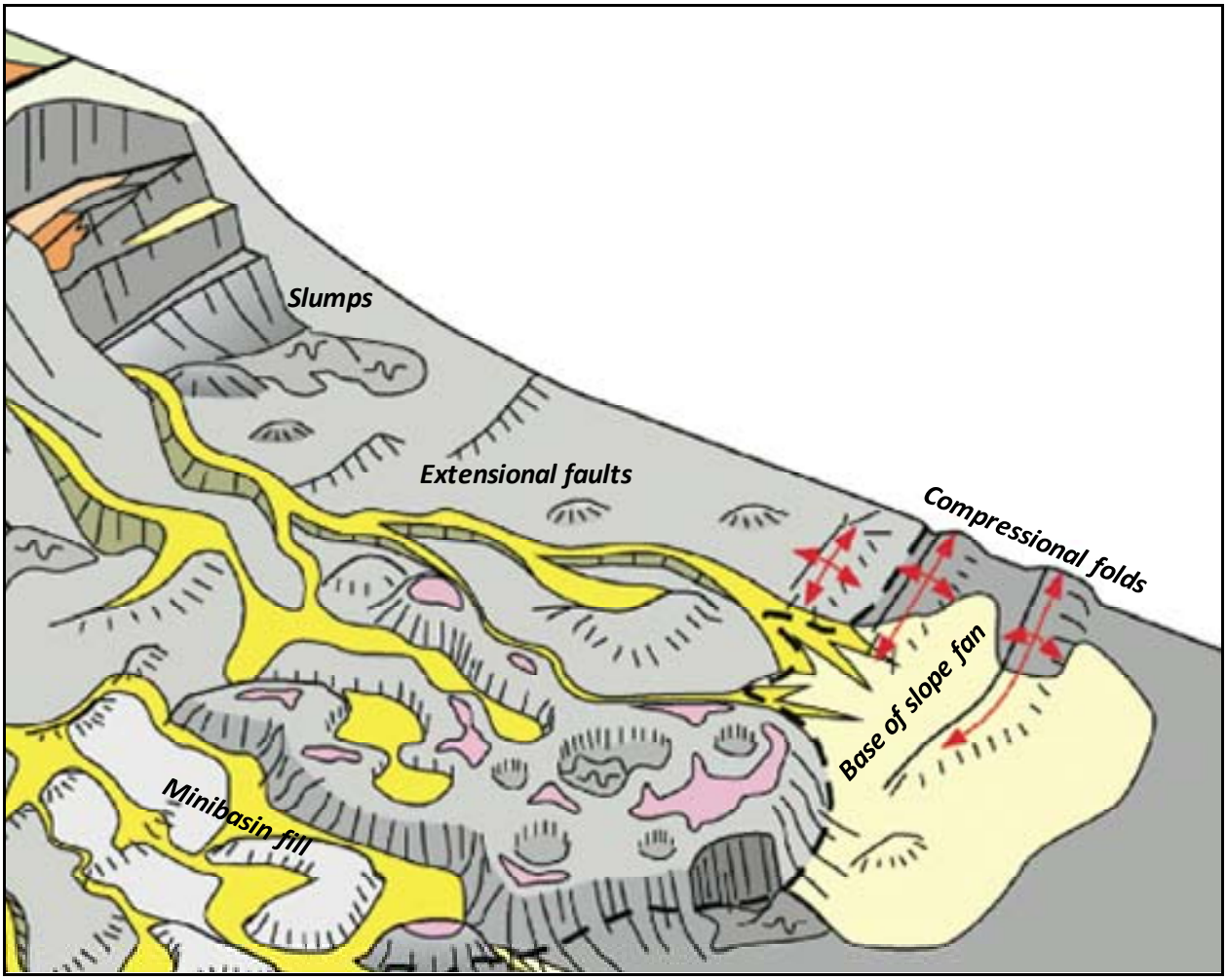


Figure 30: Depositional model details showing sand depositional systems (yellow) in minibasins, and base of slope fans (Mayall et al., 2010)

5.2.3 Neogene Deposition

5.2.3.1 *Structural and Stratigraphic Setting for Play Types*

Neogene deposition in the deepwater Gulf of Mexico is complex. All the depositional environments and systems are present and the deposition is intimately connected with salt tectonics. One way to simplify this picture is to classify fields into categories based on structural style as well as depositional styles. A proposed classification is shown in Figure 31 and groups fields into three main categories: structural, structural/stratigraphic and stratigraphic traps.

The structural traps are compressional folds, structure related to differential compaction (turtle structures) or minibasins cut by normal faults. The turtle and compressional structures mostly contain basin-floor sheet sands whereas the faulted minibasin can contain sheet, channel, or channel/levee deposits.

Structural/stratigraphic traps form on the slope in minibasins. The stratigraphic component of the trap occurs where channel margins change to shale, or where sheets or channels shale out toward lateral highs related to salt movement.

The purely stratigraphic traps are rare and occur adjacent to a shelf margin where onlap of deepwater sands against the margin provides an updip lateral sale seal. These types of traps

are typical where deepwater sands about the older Cretaceous shelf margin in the northeastern Gulf of Mexico.

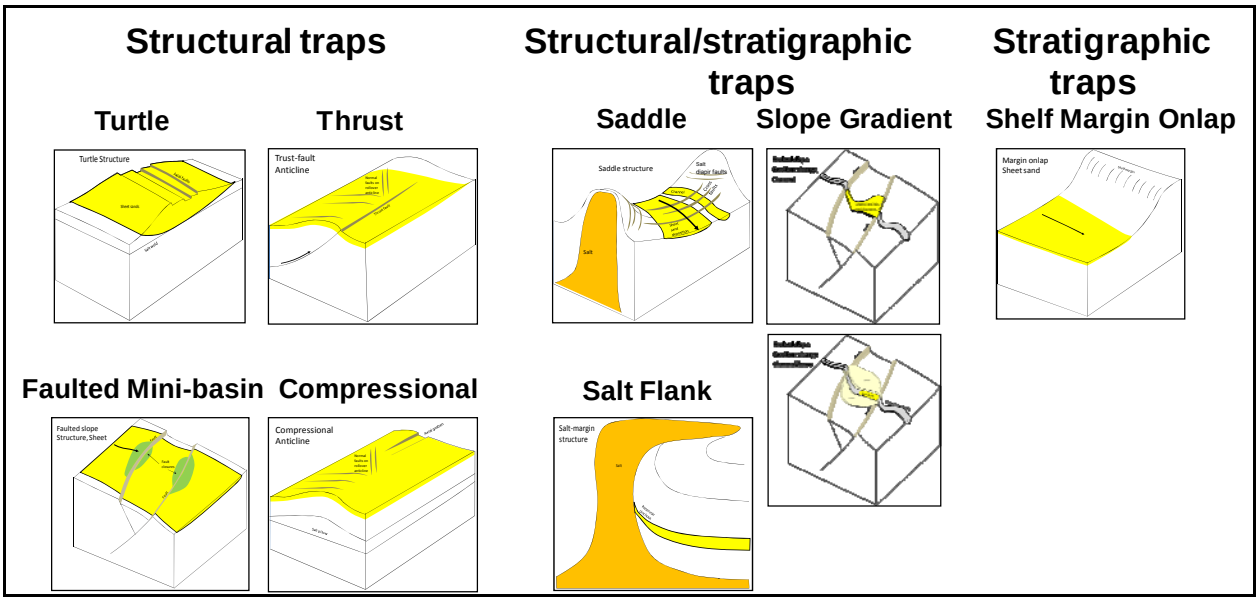


Figure 31: Field classification, deepwater Gulf of Mexico

5.2.4 Paleogene (Wilcox) Deposition

Paleogene deposition is very different from the Neogene systems described above because salt deformation is much less at this time. The deepwater Gulf of Mexico was dominated by larger depositional systems that were contemporaneous with tectonic uplift and erosion in the western US.

In the deepwater Gulf of Mexico, there are three main reservoir targets: Frio (Oligocene) sandstone, Upper Wilcox (Eocene) sandstone and Lower Wilcox (Eocene to Paleocene) sandstone (Figure 32). The Frio and Upper Wilcox only occur in the western Gulf of Mexico whereas the Lower Wilcox occurs throughout the western and central basin.

The three reservoirs occur in Alaminos Canyon fields, but the primary pay sand is the Upper Wilcox (Figure 33). A depositional model for the Wilcox is shown in Figure 34. In this model, the primary sediment input was from the northwest in large Texas deltaic systems. In other models, additional sediment was supplied by the proto-Rio Grande and other rivers from the southwest originating in Mexico. The clastic sediments from these rivers were deposited into a large depocenter that occupied the central and western Gulf of Mexico. These deposits occur as the Lower Wilcox sands in the deeper portion of Alaminos Canyon wells. These tight sands at this depth are a future target for exploitation.

Farther east, these sands can be correlated from Alaminos Canyon to the Jack and St. Malo discoveries in Walker Ridge, nearly 300 miles to the east (Figure 35). This lateral continuity shows the extent and uniformity of the deep-water Paleogene basin.

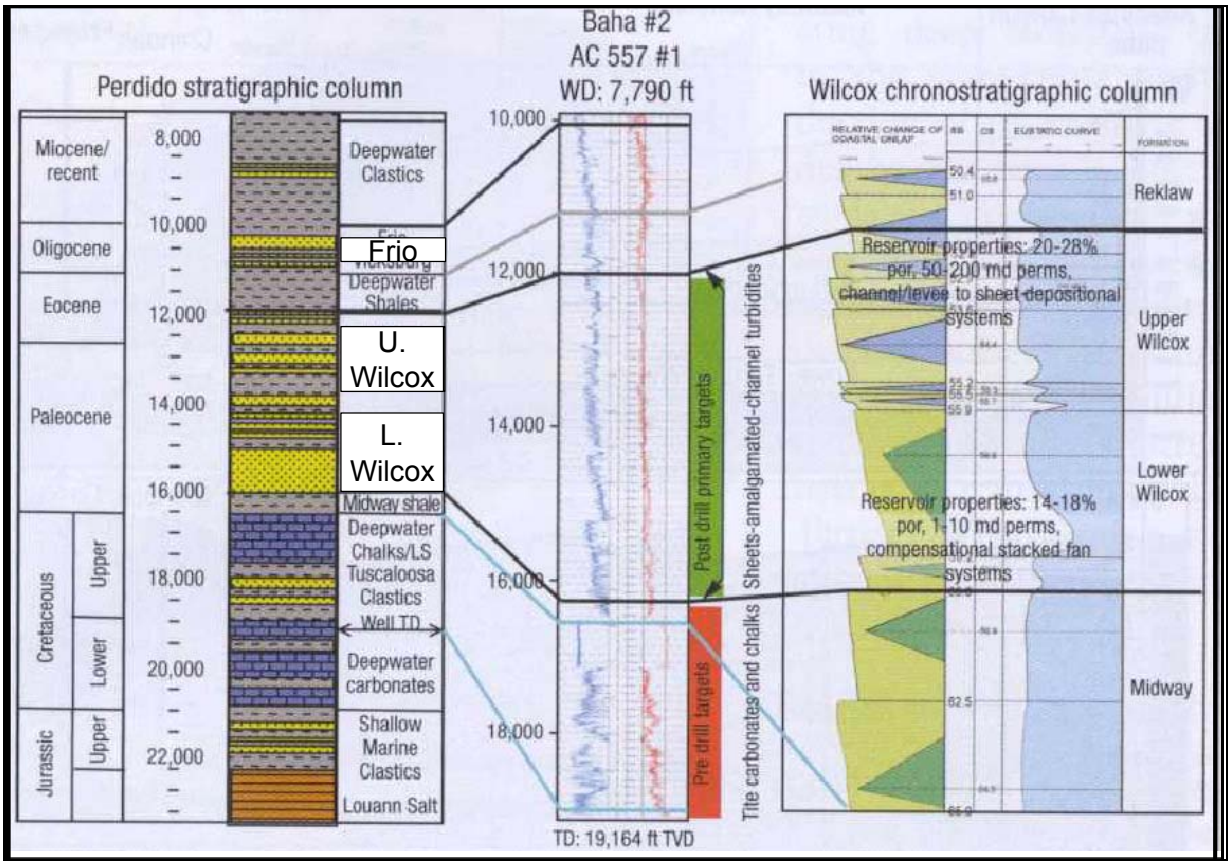


Figure 32: Major Paleogene producing formations, deep-water Gulf of Mexico (Meyer, 2001)

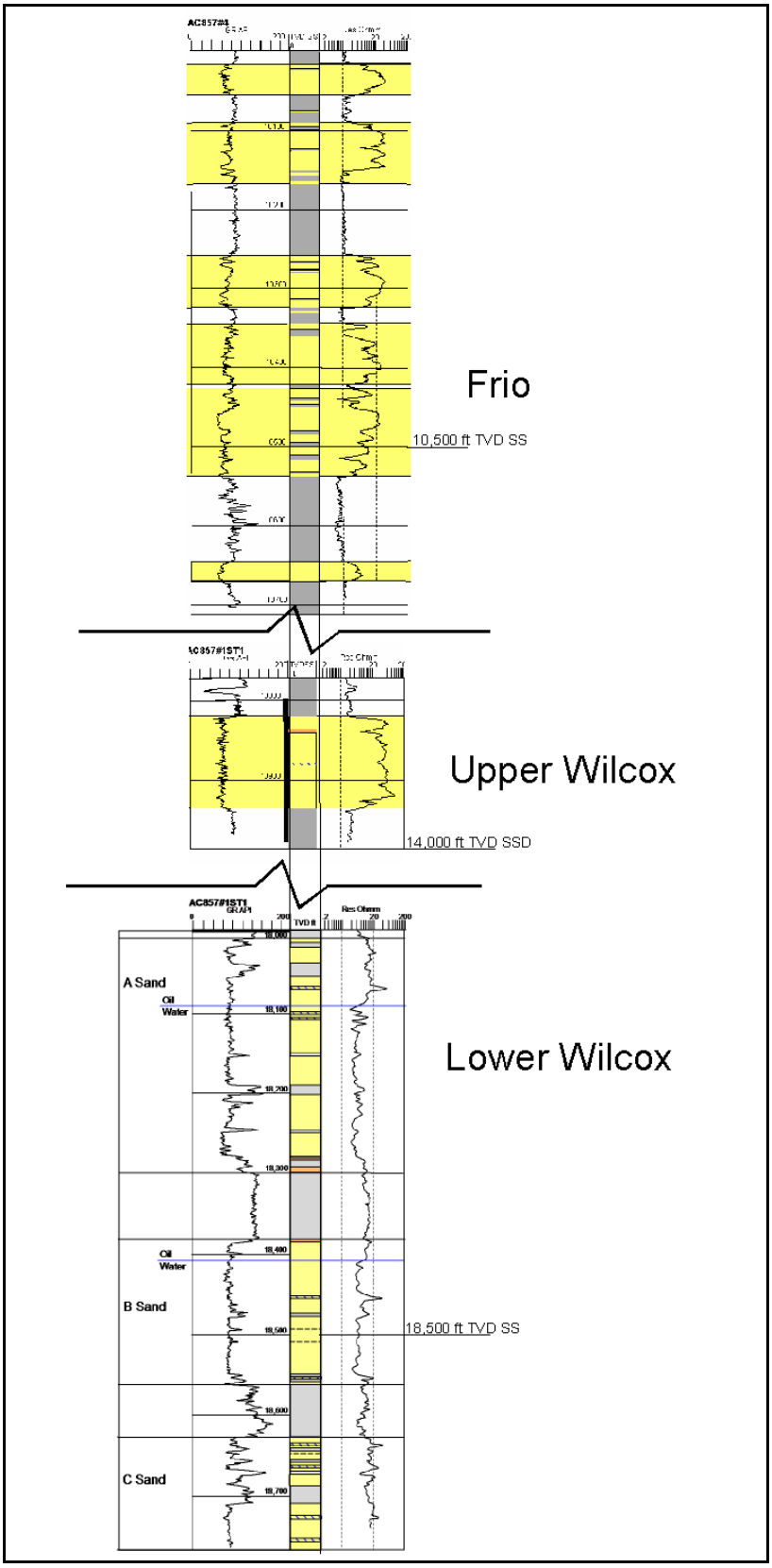


Figure 33: Paleogene reservoirs, Alaminos Canyon; Upper Wilcox is main pay sand

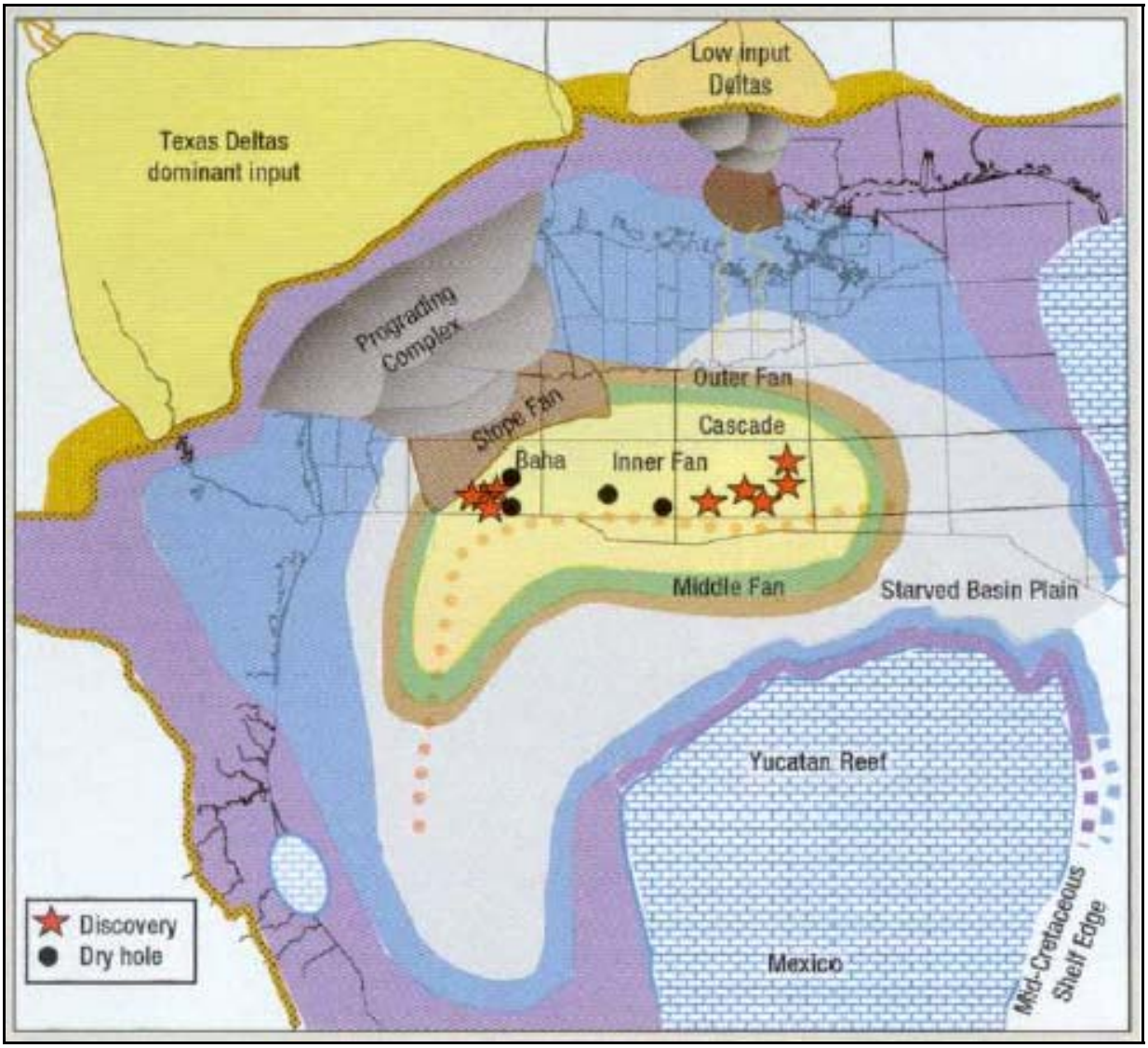


Figure 34: Wilcox depositional model (Meyer, 2001)

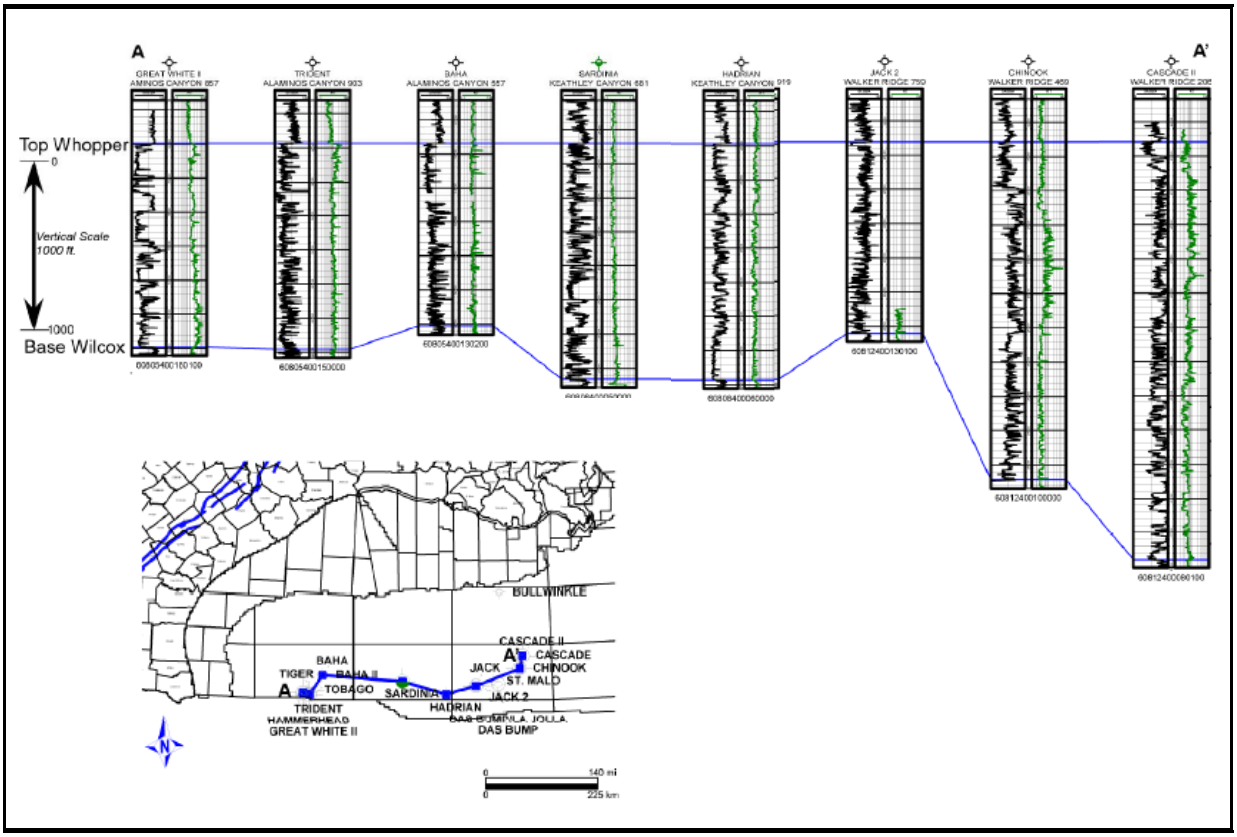


Figure 35: Wilcox stratigraphic cross-section from Alaminos Canyon to Walker Ridge (Berman and Rosenfeld, 2007)

5.3 *Diagenetic Trends and Reservoir Properties*

5.3.1 Neogene Trends

Neogene deposition is characterized by rapid sedimentation in minibasins or at the base of slope. This rapid deposition results in overpressuring and preservation of porosity in clean sand reservoirs. Diagenesis in younger rocks is minor and only becomes a factor in reservoir quality in middle and early Miocene reservoirs. As a result, permeability is strongly controlled by texture and coarse-grained sediments have higher permeability trends than fine grained reservoirs.

5.3.2 Paleogene Trends

Paleogene reservoirs are more complex than Neogene due to a longer and more complex diagenetic history. Several factors control reservoir quality of Paleogene sands:

- Reservoir mineralogy: there are more unstable minerals in these reservoirs than in younger sands. The Frio sands are contemporaneous with West Texas volcanics and have unstable glass shards in the sands. These glasses can break down into clays during diagenesis.
- Heat flow: there can be high heat flow and high temperatures in Paleogene reservoirs. This enhances breakdown of unstable minerals into clay and cement. The presence of salt canopies can lower reservoir temperature because heat is conducted by the salt away from the reservoir.

- Normal versus overpressure: there can be overpressure beneath salt canopies and this can also preserve porosity and permeability and inhibit diagenesis. Some base of slope fields face the open Gulf of Mexico and are not confined on all sides by salt walls so they can have lower reservoir pressure, even if they are beneath salt.
- Early diagenetic minerals: some early cements, such as chlorite rims, inhibit further diagenesis.

A summary of the number of discovered fields, by protraction area, and general average metrics is provided in Table 6.

Table 6: General Paleogene field metrics

Paleogene Field Metrics	West	350 Miles	East
Protraction Areas	**Alaminos Canyon**	**Keathley Canyon**	**Walker Ridge**
Field count	5	2	7
Primary reservoir	Upper Wilcox	Lower Wilcox	Lower Wilcox
Geol. age	Eocene	Paleogene/Eocene	Paleogene/Eocene
OOIP MMSTB	3,500	6,000	15,500
% OOIP	14%	24%	62%
Avg. water depth, ft	9,000 ft	5,000 ft	8,000 ft
Avg. top reservoir, ft	14,000 ft	26,000 ft	26,500 ft

5.4 *Summary of Reservoir Geology*

Geological models presented here for Neogene and Paleogene horizons point to material differences in the character of the two reservoir targets yet these individual interpretations share many of the same elements. Similar paleo-environments, turbidite deposition, and salt tectonics have produced common characteristics across the two oil plays. A generalized geological model for Tertiary reservoirs as a group is given in Table 7. Unique features distinguishing Neogene trends from the older Paleogene deposits are noted in the definition.

Table 7: Generalized geological model for Gulf of Mexico Tertiary reservoirs

Generalized Geological Model for Gulf of Mexico Tertiary Reservoirs	
Characteristic	
Paleo-environment	Deltaic
Depositional model	Submarine fan system
Age of deposits	Neogene - Upper Tertiary Paleogene - Lower Tertiary
Regional controls	Salt canopy
Facies	Channel, sheet, lobe, and levee sands
Architecture	Fold belt, anticline, 3-way closure

Regional orientation	Northeast-southwest trending structures
Petroleum trap	Compressional fold, turtle structure, minibasin, shale transition
Petroleum source rock	Upper Jurassic and Middle Cretaceous organic-rich carbonates
Formation lithology	Interbedded sandstones and shales
Reservoir targets	Neogene - Pleistocene (Quaternary), Pliocene, Miocene Paleogene - Oligocene, Eocene (Upper Wilcox), Paleocene (Lower Wilcox)
Reservoir rock	Turbidite sandstones
Texture	Neogene - coarse to fine grained; friable to consolidated Paleogene - fine-grained; consolidated
Mineralogy	Neogene - clean siliciclastics, some detritus Paleogene - siliciclastics, clay, and cement

6 Deepwater Gulf of Mexico Resource Base

6.1 *Overview of Deepwater Reservoirs*

Mature fields and reservoir in the deepwater Gulf of Mexico cover a broad spectrum of turbidite depositional environment, fluid properties, and production characteristics. Each field in particular will often have a spectrum of stacked reservoirs and fluid types. The Shell operated Auger field is used as an example of a typical field with stacked reservoirs with 3-way structural closure against salt (Figure 36). The Auger field has 6 significant reservoirs including volatile oils and retrograde gas condensates.

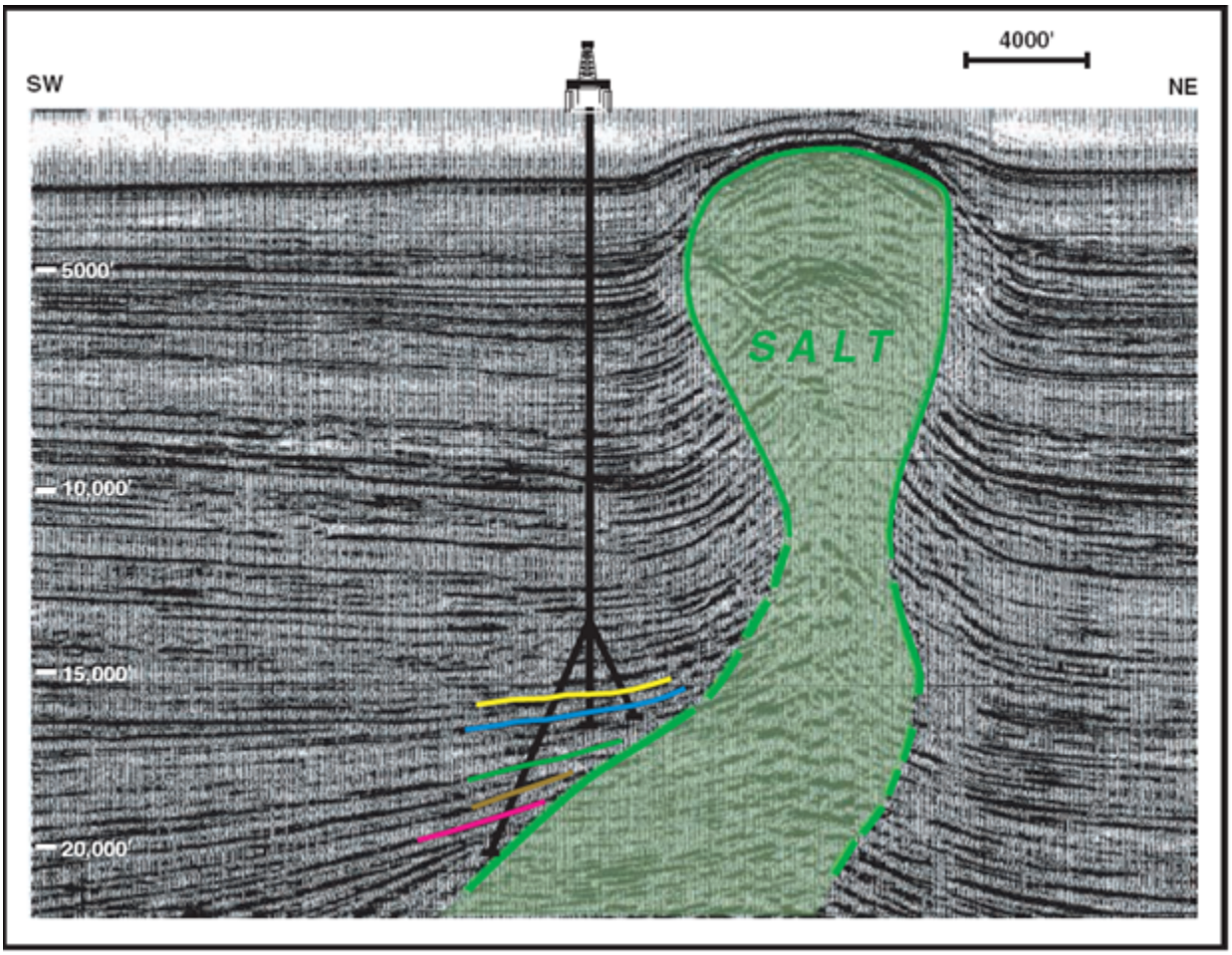


Figure 36: Auger field example of stacked reservoirs trapped against salt (Kendrick, 2000)

One characteristic common through much of the deepwater Gulf of Mexico is the presence of over-pressured reservoirs. “Sedimentation rate often exceeds the ability of sediments to drain in rapidly formed basins. As a result, pore fluid is over-pressured because it supports overlying material and sediment is under-consolidated” (Flemings, et al, 2002). The characteristics of over-pressured and unconsolidated leads to highly compacting reservoirs which provides significant natural reservoir drive energy in addition to fluid expansion and aquifer influx. Only in the Middle Miocene and older reservoirs, which have been the focus of appraisal and development during the past 10 years, is the rock more cemented and less compacting.

Waterflooding has not been common practice in the Upper Miocene and younger reservoirs due to over-pressured and compacting reservoirs. The fields where significant water has been injected from early in the development are Petronius, Lena, Horn Mountain, and Holstein. Several fields have been produced for a long period before implementing injection. These include Mars, Ursa, Princess, and Amberjack. Several other fields have had minor water injected and the projects shut down including the Pompano, Bullwinkle, Morpeth and Ram-Powell fields. For the majority of fields, operators have proceeded with primary production to evaluate drive energy and reservoir performance to determine later if the secondary recovery methods are required.

A map showing discovered and producing fields in deepwater GOM is shown in Figure 37. The Green Canyon and Mississippi Canyon areas are prolific for both number of fields and production. Other deepwater protraction areas with mature production are Vioska Knoll, Ewing Bank, East Breaks and Garden Banks. The first Paleogene or Lower Tertiary production commenced in 2010 with the Shell operated Perdido development in the Alaminos Canyon protraction area. Also, significant gas production has commenced in recent years from the Atwater Valley and eastern areas Lloyd Ridge and De Soto Canyon.

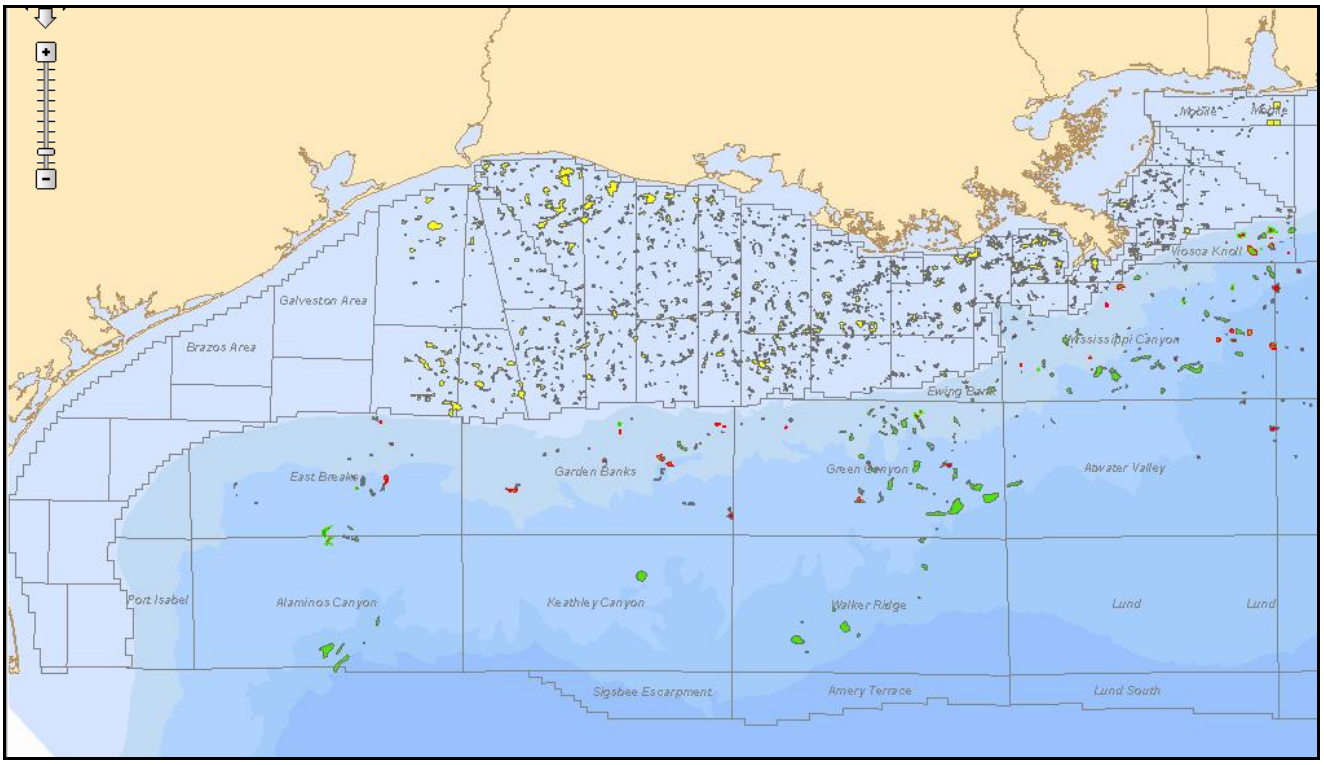


Figure 37: Map of Gulf of Mexico with deepwater fields

6.1.1 Example Reservoirs and Performance

A number of fields and reservoirs have been used to show the variability of properties and reservoir performance. The examples highlight oil recovery and drive mechanisms for mature, deepwater reservoirs and hence provide insight on remaining oil in-place. A summary of 12 reservoirs with key data is shown in Table 8. Categories of reservoir development and performance include: (1) high RF from strong aquifer in good connected sand; (2) moderate RF from highly compacting reservoir with supplemental aquifer influx; (3) low RF in reservoirs with geologic complexity; (4) waterflooded fields from the start of production; and (5) compacted

Middle Miocene reservoir with limited aquifer influx and low drive energy. The reservoirs are discussed in further detail below.

Table 8: Example mature Neogene reservoirs and oil recovery mechanisms

Class	Field	Reservoir	Primary Depositional Facies	OOIP (MMSTB)	Oil RF	API Gravity	GOR (SCF/STB)	ϕ / K (frac/md)
High RF, strong aquifer	Troika	S10	Sheet sand	254	60%	38	1660	0.30/1700
	Auger	S	Sheet sand	189	45%	37	1950	0.29/1100
	Bullwinkle	J	Sheet sand	209	45%	27	1000	0.30/1200
Moderate RF, high compaction and mod. aquifer	Genesis	N3L	Channel sand	93	37%	28	1027	0.29/300
	Pompano	M83C-85A	Channel sand	196	47%	34	1000	0.30/1130
	Medusa	T1B	Channel sand	111	40%	30	900	0.28/1290
Depositional and structural complexity	Ram Powell	N	Channel sand	84	20%	35	1400	0.29/825
	Front Runner	FR-46D	Sheet sand	100	23%	28	815	0.26/870
	Marco Polo	M10-M60	Channel sand	31	25%	32	800	0.30/600
Waterflood from start	Petronius	J1	Sheet sand	92	52%	31	700	0.29/490
	Horn Mountain	M	Channel sand	279	40%	33	800	0.28/300
Middle Miocene with limited drive energy	K2	M20	Sheet sand	374	20%	30	600	0.21/700

6.1.1.1 *High Oil Recovery from Strong Aquifer Drive*

The Troika S10, Auger S and Bullwinkle J reservoirs have good connectivity over a large volume of OOIP and strong natural aquifer influx. The S10 and S reservoirs also have volatile oils with high GOR and low oil viscosity. Thus, the aquifer has provided a near piston-like displacement and wells watered out quickly once the water level reached the well.

The Troika field (Figure 38) is particularly unique with very high oil recovery of 60% in a subsea development tied back 14 miles to the host platform. The S10 reservoir was developed with 5 wells, each of which achieved high oil rates and the reservoir was depleted after only six years.

The J sand is the largest reservoir in Bullwinkle field. Water injection equipment was included in the development, and injection commenced after 2.5 years. The injection was stopped after less than 4 years since it was concluded that the natural aquifer influx and rock compaction drive was providing better recovery performance.

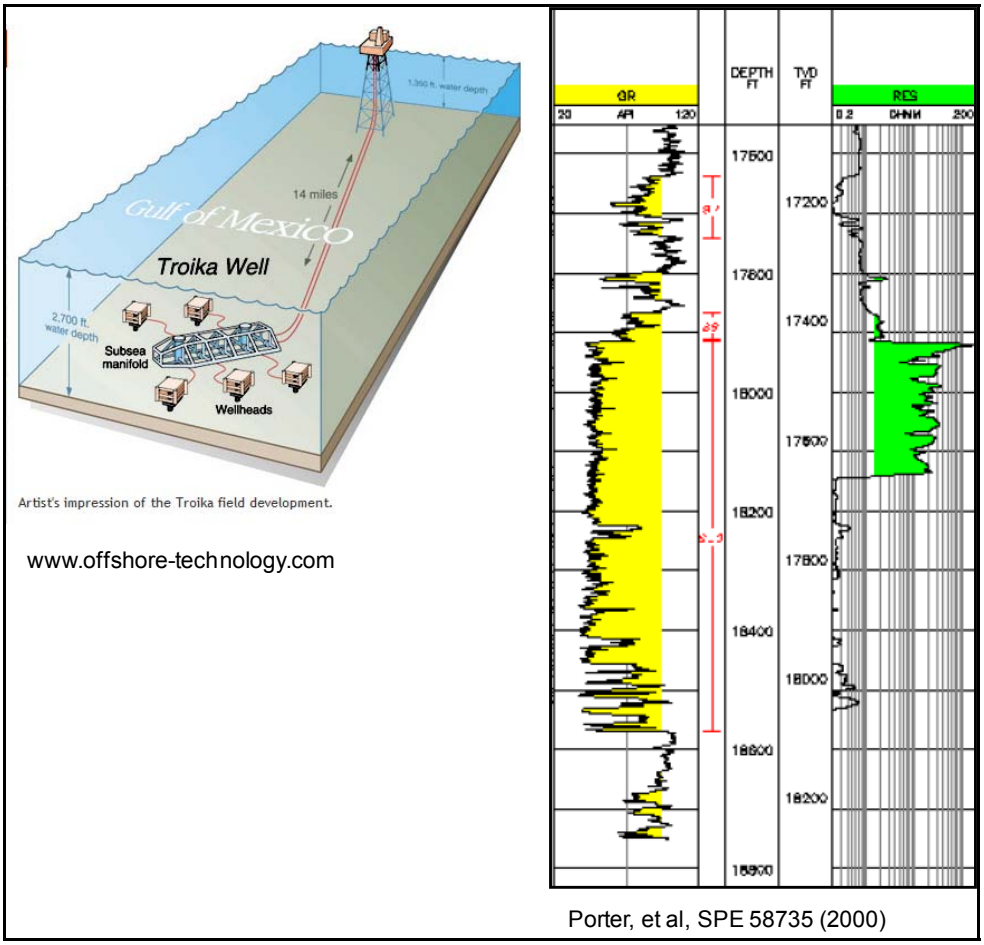


Figure 38: Troika field subsea development and type log

6.1.1.2 *Moderate Oil Recovery in Highly Compacting Reservoirs with Supplemental Aquifer/Water Drive*

The Genesis N3L, Pompano M83C-85A, and Medusa T1B reservoirs are examples with moderate to high oil recovery due to mixed rock compaction and aquifer influx. The three examples are channel-levee depositional complexes with the majority of reserves in high quality channel sand.

The N3L reservoir performance has been described in detail by Pourciau, et al (2003) and Sweet and Sumpter (2007). In general, the N3L reservoir in reasonably connected and most wells are supported by the aquifer. The reservoir is highly compacting and has exhibited extreme permeability reduction with falling reservoir pressure (Figure 39). The reservoir pressure, on average, has only fallen 25% of original value and has stabilized with aquifer influx. A combination of stratigraphic heterogeneity and faulting has limited oil recovery to a forecast 37% of OOIP.

The Pompano M83C-85A has included water injection for 4 years to supplement natural drive energy. The resulting forecast of oil RF is 47% of OOIP.

The Medusa field, T1B reservoir has separate east and west accumulations which are not in communication. The reservoir is both highly compacting and contains a reasonable size aquifer. Producing water cut is in excess of 50% and the forecast RF is 40%.

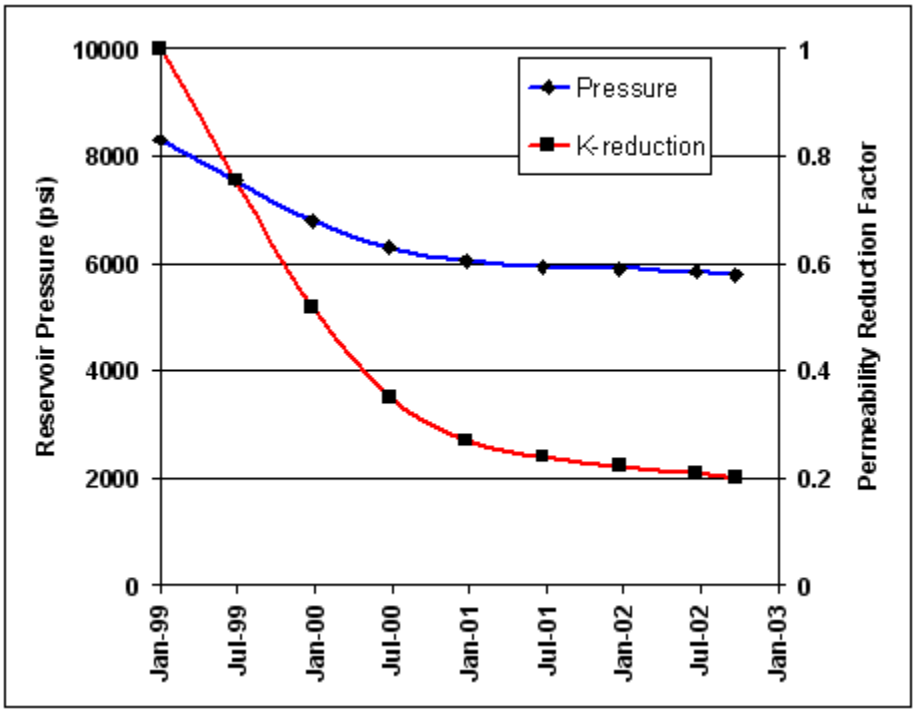


Figure 39: Genesis, N3L pressure and permeability decline

6.1.1.3 ***Low Oil Recovery in Complex Depositional and Structural Geology***

The Ram Powell N, Front Runner FR-46D, and Marco Polo M10-M60 reservoirs have all experienced a rapid decrease of oil rate due to reservoir complexity. The N sand has been described (Kendrick, 2000) as a channelized reservoir where development well drilling penetrated "perched" water at structurally high locations (Figure 40). Subsequent drilling of the A-5 horizontal well, in an attempt to avoid the perched water and connect up multiple channels sand members (Bramlett and Craig, 2002) showed the stratigraphic complexity of a stacked channel complex. Current oil recovery is only 20% of OOIP.

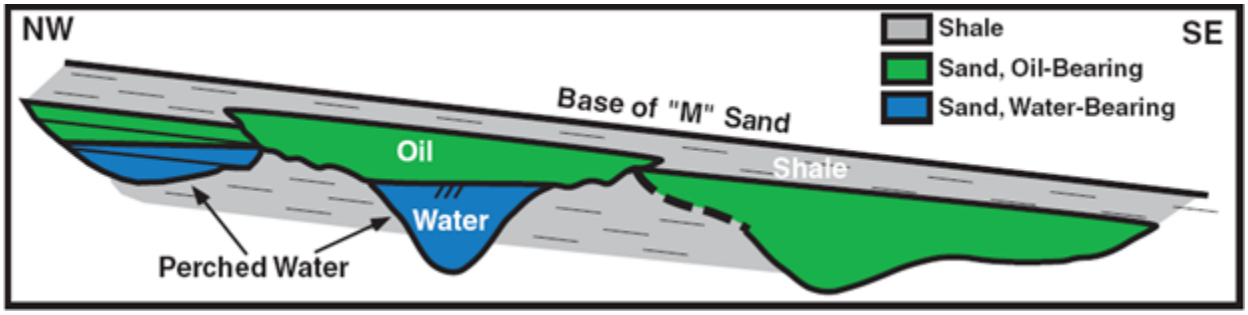


Figure 40: Perched water in channel sand, Ram Powell N reservoir (Kendrick, 2000)

The Front Runner FR-46D reservoir was penetrated by multiple wells during appraisal drilling and was interpreted as thick and laterally extensive sheet sand. Production from two wells declined quickly demonstrating poorer connectivity of oil in-place due either to sub-seismic faulting or depositional complexity. The forecast oil RF is 23% of OOIP.

Production in the Marco Polo development declined rapidly due to poorly connected channels sands and vertical heterogeneity. The stacked channel sands are poorly amalgamated, and additional baffles to lateral flow appear to be present. The forecast of oil RF is 25% of OOIP.

6.1.1.4 *Moderate to High Recovery Factor in Waterflooded Fields*

Water injection was implemented from near the start of production in the Petronius and Horn Mountain fields. The Petronius J sand had an initial gas cap and the oil was saturated at initial conditions. Also, the J sand, and other reservoirs in the Viosca Knoll area only moderately over-pressured, hence injection was planned to supplement the expected solution gas drive. The J sand is laterally extensive sheet sand and has responded well to down dip, peripheral water injection. The waterflood in Petronius has been very successful with forecast RF of 52% of OOIP.

It is worth noting that all fields with significant water injection, thus far, have dry tree facility solutions. One subsea water injection project was engineered in the ENI operated Morpeth field (Shumbera, 2003), but injection was halted after 5 months due to reservoir reasons.

There is a detailed description of the Horn Mountain, M sand waterflood project by Milkov, et al, 2007. Seven producers are supported by two peripheral water injectors. Time-lapse geochemistry has provided insight on the complexity of fluid movement between injector and producers in a channel-overbank depositional environment. The lower forecast RF of 40% is indicative of this complexity. It was also noted by subsequent presentations made by operator BP (SPE Delta Section Deepwater Symposium, 2009) that the aquifer is providing >80% of the water drive energy and water injection is only providing supplemental support.\

6.1.1.5 *Low Oil Recovery Factor in Middle Miocene with Limited Drive Energy*

The K2 field is used as an example of recent development in a deep (25,000 ft), Middle Miocene reservoir with low rock compressibility. The reservoir is moderately over-pressured with initial average pressure of 14,500 psi and a gradient to mean sea level of 0.58 psi/ft.

The reservoir trap is a 3-way closure against salt dipping at 25˚ with a thick (12,000 ft) allochthonous salt layer above the formation (Figure 41). Reservoir sands were deposited as sheet-like turbidites in a basin floor fan setting. Production from six development wells showed rapid pressure and oil rate decline, and a low oil recovery was forecasted due to the lack of natural drive energy. The forecast of oil RF is 20% of OOIP.

Operator Anadarko and its partners immediately put in place an EOR/IOR task force (Lim, 2008). Initial screening concluded that water or nitrogen injection were the most technically viable IOR solutions for the K2 field. Laboratory studies were used to characterize the phase behavior of the K2 oils, and the work reported by Lim, et al (2008) reports results for the shallower M14 zone. Of significance in the evaluation of gas injection IOR processes the following were observed:

- The M14 reservoir oil contains 10% by weight asphaltene and an asphaltene onset pressure (AOP) of 4400 psi. There is an increase in asphaltene instability with the addition of gas and increasing GOR. Where hydrocarbon gas is added and GOR increases from 624 to 900 SCF/STB, the AOP increases to 15,000 causing concern of deposition in the reservoir. For the addition of N2 and a similar GOR increase, the AOP increases to only around 5600 psi.
- The nitrogen minimum miscibility pressure (MMP) was experimentally measured to be no greater than 6000 psi. Thus, nitrogen flooding would be a miscible process if used at K2.

- Laboratory analysis and reservoir modeling showed the importance of controlling viscous instability by using reduced injection rates and for implementing gravity stable top-down flooding.

The review of IOR potential at K2 field demonstrated the significant cost and technical challenges in engineering a major injection project for a field 175 miles south of New Orleans, in 4400 feet water depth, and with wet trees tied back 6 miles to the Marco Polo floating production facility. The K2 field partners have drilled recent downdip wells (Figure 38) to further develop the field and better characterize the reservoirs, and the IOR evaluation continues.

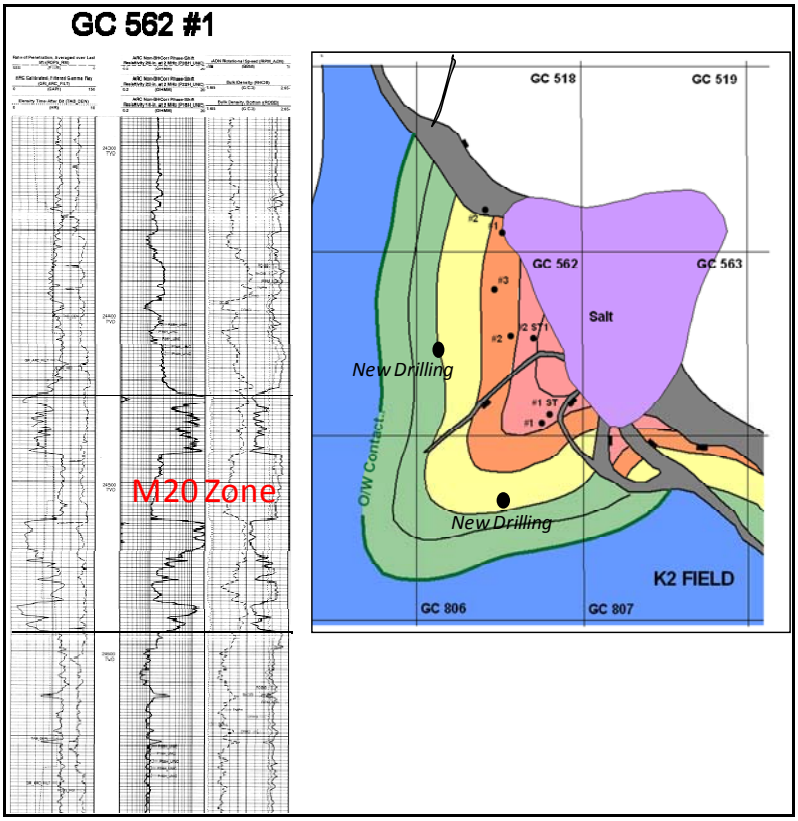


Figure 41: K2 field, M20 reservoir map and type log

6.2 *Pleistocene and Neogene Resource Base*

Production volumes and various other data from discovered fields on the Federal Outer Continental Shelf (OCS) are reported by the field operators to the Minerals Management Service (MMS), which ultimately releases the data to the public. Knowledge Reservoir, LLC has built a knowledge base accessible by subscription, ReservoirKB©, in which publicly-available data from MMS and many other sources have been systematically compiled, organized, and analyzed. Much of the information presented in this report comes from ReservoirKB.

The most recent published GOM-wide figures for estimated ultimate recovery (EUR) come from MMS Report 2008-034. Although released in 2008, this report presented estimated volumes as of 31-Dec-2004. The EUR of both oil and gas from the entire Federal OCS GOM (shelf + deepwater) was projected to be 50.6 billion barrels oil equivalent (BOE), of which 19.0 billion bbl (37%) was oil. Of this 19.0 billion bbl oil EUR from the entire GOM, 14.1 billion bbl had been produced as of end-2004, and about 4.8 billion bbl oil remained as reserves (i.e., still to be

produced). An additional 2.8 billion bbl oil EUR was projected to come from unproved fields (i.e., fields which have been discovered but not yet developed).

Deep water production to date has come mainly from reservoirs in the Miocene and Pliocene (collectively Neogene) formations of the Upper Tertiary, with some contributions from Pleistocene reservoirs in the Quaternary.

Because the Lower Tertiary trend was in its early days as of end-2004, the reported proved volumes in MMS Report 2008-034 exclude most Paleogene discoveries. The MMS report does not break out the EUR for deepwater fields using the current definition (i.e. water depths greater than 1,000 ft). However, the report does provide data sorted by protraction area. Making the reasonable assumption that essentially all of the reserves and production in certain protraction areas came from deep water, the EUR of oil from proved fields was 7.2 billion bbl (of which 3.0 billion bbl had been produced as of 31-Dec-2004). Another 2.6 billion bbl of estimated recoverable oil was predicted to come from unproved fields. Thus, the total EUR of oil from discovered fields in DW GOM was 9.8 billion bbl as of end-2004

On the Federal OCS, including both shelf and deepwater, MMS report 2008-034 identifies a total of 1,379 fields (1,172 proved, 58 unproved, and another 149 discoveries which are either still being evaluated or have been relinquished without being developed).

6.2.1 Neogene Field and Reservoir Database

ReservoirKB was used to compile properties and statistics on a field and reservoir basis which includes forecasts of ultimate recovery and remaining oil in place (ROIP). In this work we refer to the ROIP as the “Size of the Prize” or target for IOR projects.

Only oil fields are included in the database. A list of mature deepwater GOM oil fields, where production commenced between 1979 and 1999 is provided in Table 9. A list of newer fields which started production between years 2000 and 2009 is given in Table 10. The database includes a total original oil in-place of 25.3 billion bbl and forecast EUR of 7.3 billion bbl oil and 10.3 TCF gas. As mentioned above, the MMS discovered oil total EUR is 9.8 billion bbl which includes discovered but undeveloped fields.

The average oil RF has been determined for Neogene/Pleistocene reservoir using a statistical average rather than the volume weighted average. The volume weighted average shown above (7.3 B bbl divided by 25.3 billion bbl) is 28.9%. For the purposes of this report we have used the statistical average oil recovery factor of 31.6% the distribution of which is shown in Figure 42. The statistical average recovery factor is based on the analysis of 343 reservoirs where the P90 to P10 range of RF is 16% to 48%.

The average oil RF of 31.6% is applied to the MMS estimated EUR of 9.8 MMSTB to estimate the OOIP of 31 billion bbl for discovered Neogene and Pleistocene age reservoirs. Therefore, the remaining size of prize or ROIP forecast for Neogene reservoirs is 21 billion bbl. The forecast of ROIP for the largest 45 developed fields with Neogene/Pleistocene age reservoirs is shown in Figure 43. The figure also shows the forecast of oil EUR for the fields.

Table 9: Mature oil fields (1979 – 1999) with OOIP and forecast EUR and ROIP

Field	First Production Year	Number of Significant Reservoirs	OOIP (MMSTB)	RF	Oil EUR (MMSTB)	Gas EUR (BSCF)	Well Count[1]	Total EUR (MMBOE)	Recovery/ Well[2]	Remaining (MMBOE)
Cognac	1979	5	395	16.8%	66	557	46	162	4	2
Lena	1988	6	212	20.7%	44	212	43	80	2	2
Bullwinkle	1989	5	340	39.1%	133	170	19	162	9	26
Jolliet	1989	11	265	13.7%	36	136	20	60	3	4
Amberjack	1991	6	264	28.6%	75	70	38	88	2	8
Pompano	1994	6	448	32.0%	143	251	39	186	5	21
Auger	1994	5	288	47.9%	138	324	20	194	10	0
Prince	1994	0	49	18.1%	9	9	5	10	2	3
Cooper	1995	7	183	1.0%	2	5	4	3	1	0
Mars	1996	16	3391	29.8%	1011	1096	23	1200	52	584
Ursa	1996	3	1326	29.8%	395	634	11	504	46	154
Llano	1996	6	360	8.6%	31	73	2	44	22	5
Manatee	1996	2	47	27.7%	13	9	2	15	7	4
Rocky	1996	0	10	45.3%	5	7	1	6	6	0
Ram-Powell	1997	4	404	32.7%	132	966	17	299	18	82
Troika	1997	2	292	56.2%	164	326	7	220	31	3
Neptune	1997	4	137	42.5%	58	107	17	77	5	5
Salsa	1998	6	196	32.0%	63	254	5	106	21	16
Baldpate	1998	5	189	49.7%	94	244	9	136	15	14
Morpeth	1998	3	110	35.3%	39	36	4	45	11	17
Arnold	1998	2	71	27.6%	20	17	3	23	8	1
Genesis	1999	10	437	30.9%	135	186	15	167	11	42
Macaroni	1999	7	181	8.3%	15	28	3	20	7	4
Manta Ray	1999	4	120	19.5%	23	18	2	27	13	22
Allegheny	1999	4	110	40.2%	44	81	4	58	15	8
Angus	1999	1	68	56.5%	38	57	3	48	16	3

Notes:

1. Oil and gas producers are counted.
2. Total EUR is applied for calculation.
3. There are three wells counted in Mars which have been converted to injectors.

Table 10: New oil fields (2000 – 2009) with OOIP and forecast EUR and ROIP

Field	First Production Year	Number of Significant Reservoirs	OOIP (MMSTB)	RF	Oil EUR (MMSTB)	Gas EUR (BSCF)	Well Count	Total EUR (MMBOE)	Recovery/ Well	Remaining (MMBOE)
Europa	2000	6	305	29.3%	89	126	7	111	16	53
Petronius	2000	3	233	57.2%	133	192	15	166	11	23
Hoover	2000	1	141	45.4%	64	76	6	77	13	10
King764	2000	2	50	24.7%	12	15	1	15	15	3
Black Widow	2000	1	21	52.5%	11	10	1	13	13	1
Brutus	2001	6	369	38.0%	140	188	8	173	22	69
Crosby	2001	6	197	19.1%	38	50	3	46	15	2
Oregano	2001	2	58	39.8%	23	35	3	29	10	5
J.Bellis	2001	2	40	15.4%	6	5	4	7	2	0
Typhoon	2001	2	68	40.2%	27	38	4	34	9	0
Ladybug	2001	2	32	32.1%	10	11	2	12	6	2
Marshall	2001	1	24	34.4%	8	7	2	9	5	2
Horn Mountain	2002	2	320	34.7%	111	103	8	129	16	36
Nansen	2002	4	152	45.8%	70	416	12	141	12	29
Aspen	2002	6	150	19.3%	29	29	4	34	8	2
King	2002	2	135	54.2%	73	100	3	90	30	15
Boomvang North	2002	2	72	48.6%	35	50	5	44	9	4
Hack Wilson	2002	1	35	29.7%	10	14	1	13	13	4
Drysdale	2002	1	30	26.7%	8	11	2	10	5	6
Lou Gerhig	2002	1	30	26.5%	8	8	1	9	9	2
Madison	2002	1	26	38.1%	10	7	1	11	11	0
Medusa	2003	6	370	12.2%	45	48	8	53	7	12
Princess	2003	2	295	26.6%	79	130	3	101	34	52
Gunnison	2003	5	137	17.7%	24	177	13	55	4	7
Matterhorn	2003	3	77	16.8%	13	22	7	17	2	0
Habanero	2003	2	75	23.5%	18	32	2	23	12	1
Herschel	2003	2	75	24.2%	18	22	1	22	22	10
Boris	2003	2	42	28.1%	12	19	2	15	8	0
Zia	2003	1	30	23.3%	7	5	1	8	8	2
Holstein	2004	8	526	45.1%	237	243	13	279	21	229
Front Runner	2004	9	385	8.6%	33	33	5	39	8	18
Kepler	2004	2	184	71.7%	132	149	2	158	79	81
Magnolia	2004	3	162	18.7%	30	96	8	47	6	17
Devils Tower	2004	3	110	28.8%	32	30	9	37	4	7
Ariel	2004	5	94	64.9%	61	82	3	75	25	35
Triton	2004	2	85	25.9%	22	15	2	25	12	7
Glider	2004	2	50	23.6%	12	9	2	13	7	5
Marco Polo	2004	1	31	31.9%	10	13	6	12	2	2
Dawson	2004	1	15	10.0%	2	4	1	2	2	1
Mad Dog	2005	2	937	27.2%	255	139	8	279	35	229
K2	2005	3	450	16.4%	74	59	3	84	28	55
Swordfish	2005	1	50	39.0%	20	73	1	32	32	13
Lorien	2005	1	36	30.6%	11	11	2	13	6	3
Constitution	2006	6	275	11.1%	31	46	6	39	6	23
Gomez	2006	1	49	36.9%	18	57	3	28	9	13
Ticonderoga	2006	2	35	24.8%	9	8	3	10	3	1
Sw Horseshoe	2006	1	20	11.9%	2	3	1	3	3	1
Shenzi	2007	3	2006	15.0%	300	120	10	321	32	305
Atlantis	2007	5	1385	40.3%	558	361	8	620	78	603
Neptune (At)	2007	2	535	23.4%	125	25	6	129	22	128
Deimos	2007	7	428	30.0%	128	105	3	147	49	138
Cottonwood	2007	1	15	64.1%	10	43	2	17	9	14
Thunder Horse	2008	8	1895	34.5%	653	518	9	742	82	741
Blind Faith	2008	5	610	11.5%	70	50	4	79	20	79
Power Play	2008	1	10	3.9%	0	4	1	1	1	0
Tahiti	2009	4	1384	28.9%	400	160	5	428	86	428

Note:

1. Some fields are will drill new wells in the future, such as Thunder Horse and Atlantis.
The values of recovery/well are current approximations.

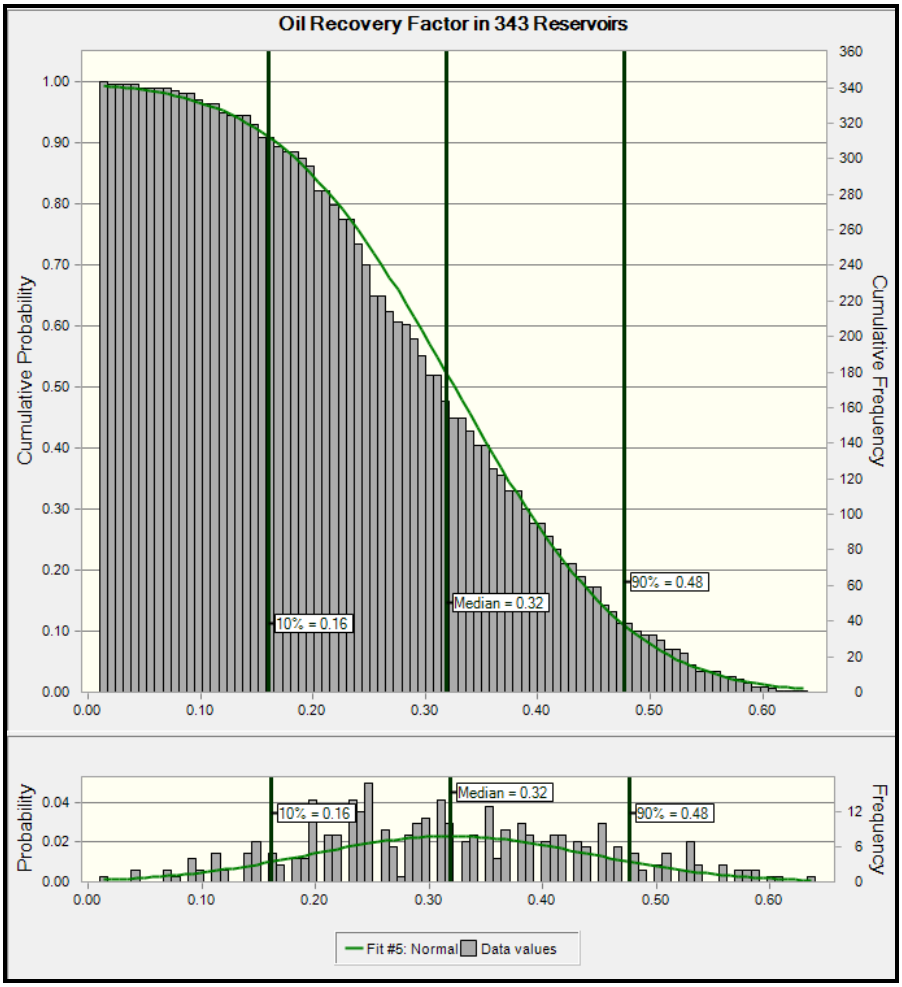


Figure 42: Oil recovery factor statistics, 343 deepwater GOM reservoirs

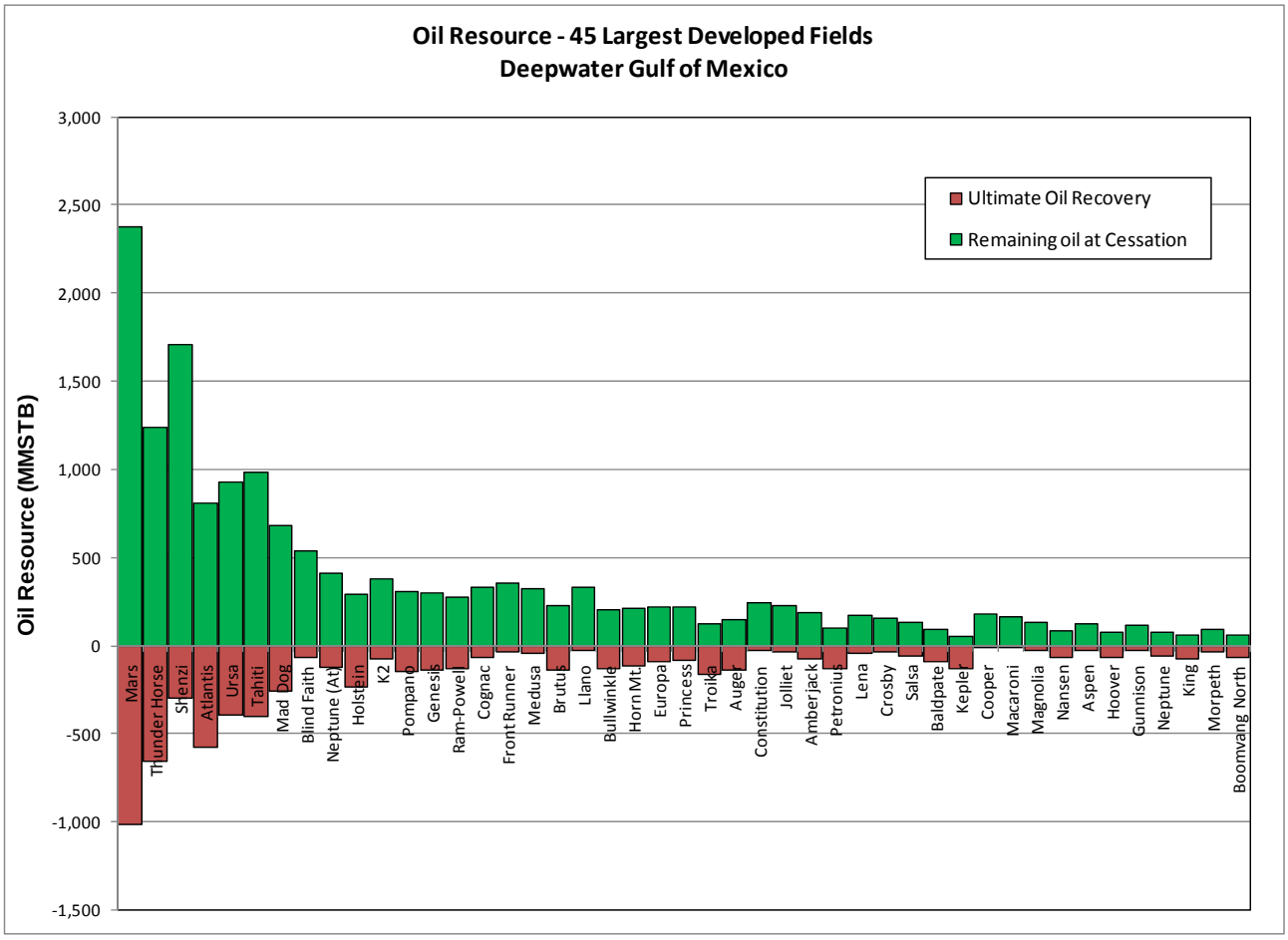


Figure 43: Forecast ROIP at cessation of production for 45 largest developed Neogene fields

Approximately 450 reservoirs in 80 fields which are predominantly oil (black oil, volatile oil, or saturated oil with gas cap) were collectively reviewed for reservoir size statistics. The number of reservoirs per field ranges from 1 - 28, with an average of 5.9 reservoirs per oil field. The total discovered OOIP in the database by field and reservoir is 25.3 billion bbl.

Figure 44 shows the frequency distribution of reservoir size or OOIP. The distribution is highly skewed towards small reservoirs, with 365 out of 464 oil reservoirs (57%) having an OOIP of 50 Million Bbl (MMB) or less. The mean reservoir OOIP volume is 50.1 MMB.

As well as the number of reservoirs in each 50 MMB bin range increment, Figure 44 also shows the total OOIP per bin range. Although the 0-50 MMB range has 57% of the reservoirs, it holds only 19% of the total OOIP for the entire set. At the other end of the scale, while there are only a relatively small number of larger reservoirs, they hold a substantial proportion of the total OOIP. Figure 45 shows that the size distribution of those oil reservoirs follows nearly perfectly the well known 80/20 rule where 80% of the total OOIP is in 20% of the reservoirs. Another significant observation on the size distribution is that the 25 largest reservoirs hold half the total OOIP.

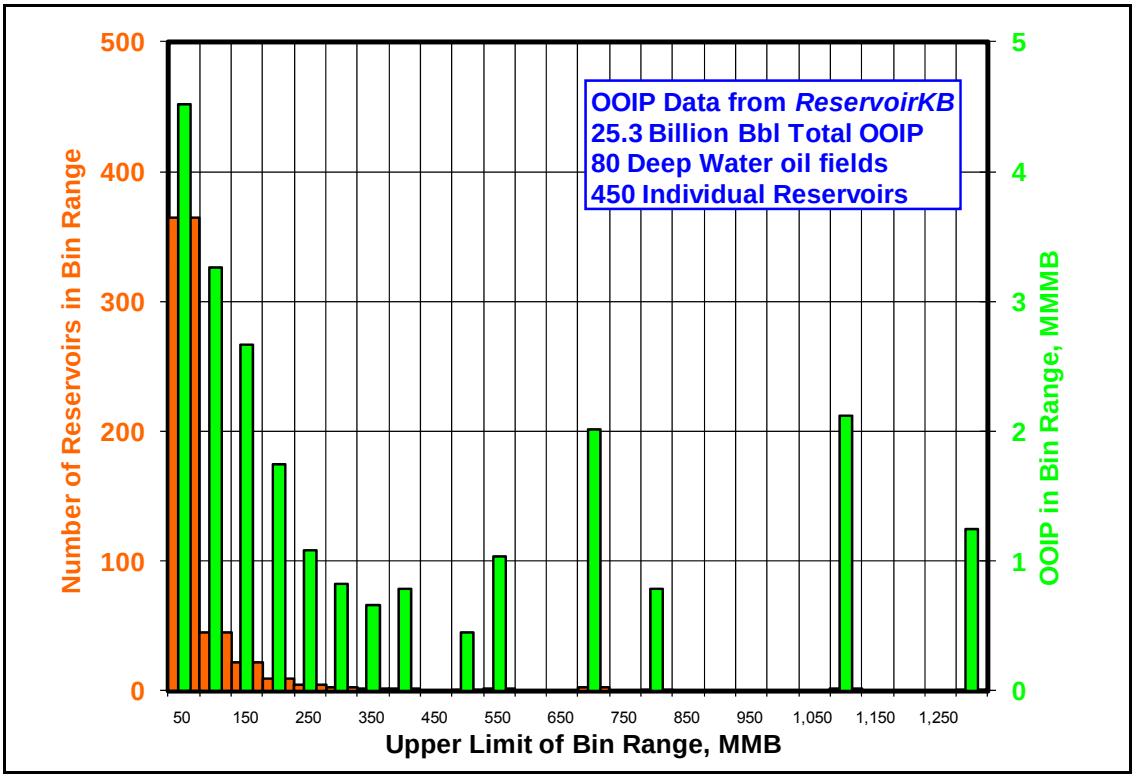


Figure 44: OOIP size distribution for Neogene

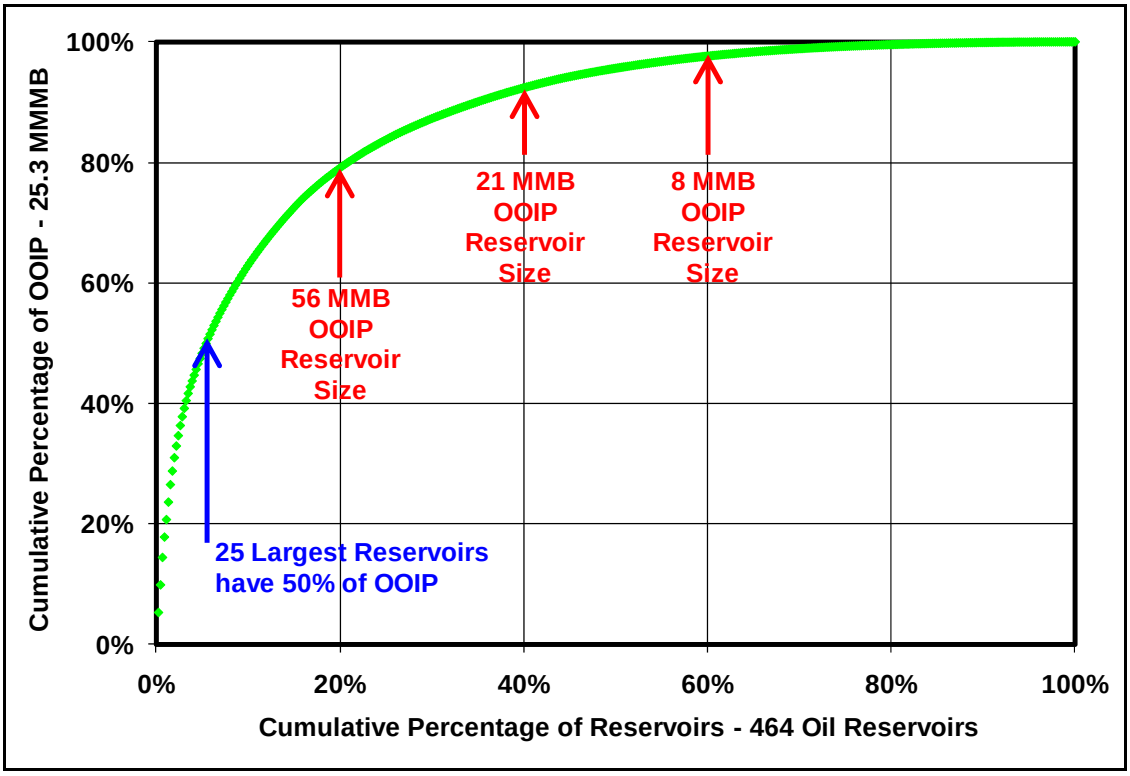


Figure 45: Cumulative OOIP distribution, Neogene reservoirs

This distribution of reservoir sizes presents a real challenge for IOR in the DW GOM. Development costs in deep water are very high where individual wells can cost $120 Million to drill, complete, and tie back to a production facility. Small reservoir size and high well costs make it difficult to economically justify incremental development projects. Therefore, improved oil recovery methods will tend to be focused on the more significant reservoirs. More optimistically, a large proportion of the DW GOM oil resource base in concentrated in a small number of larger reservoirs where IOR processes may be more feasible.

Figure 46 shows the OOIP size distribution of the 80 oil fields. It shows that 90% of the total OOIP is in 50% of the fields, and these fields have greater than 150 MMB of OOIP. Also, the 8 largest fields hold about half the total OOIP, with each having more than 610 MMB OOIP. As with the reservoir size distribution, there is a clear concentration of the OOIP into a relatively small number of larger fields. These would be expected to provide the prime targets for IOR, because their larger volumes could provide a bigger base over which to amortize the fixed costs of wells and equipment. IOR is expected to be very challenging in smaller fields in the high-cost development environment of the DW GOM.

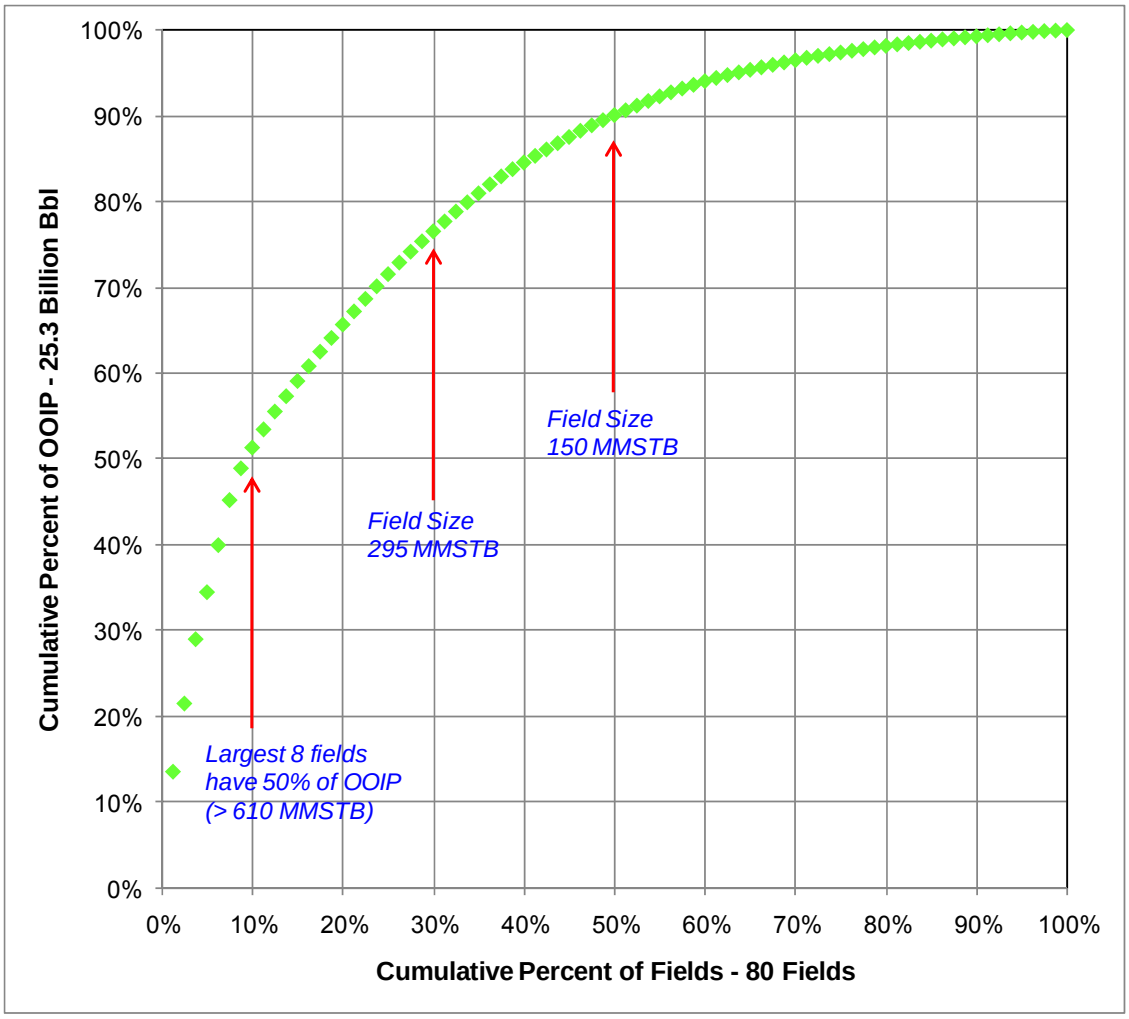


Figure 46: Total field OOIP distribution

6.3 *Discovered Paleogene Resource Base*

6.3.1 Paleogene Trend and Reservoir Description

The target horizon in the DW GOM Paleogene trend is the Paleocene/Eocene Wilcox formation, which has been an important onshore gas producing trend since the late 1920s. Top Wilcox ranges from about 12,000 ft SS in the western GOM (Perdido fold belt in Alaminos Canyon) to more than 30,000 ft SS in the central GOM (Walker Ridge). Much of the deepwater Wilcox trend is located under modern allocthonous salt canopies ranging from 7,000 to 20,000 feet thick.

First discovery in the deepwater Paleocene was the Trident prospect in Alaminos Canyon in 2001. A number of follow-up discoveries were made in Alaminos Canyon and in Walker Ridge to the east in 2002 and 2003. The only production to date has been a 23-day test on the Jack #2 well in 2006, where Chevron announced a sustained flow rate of over 6,000 BOPD, and the recent start up of the Perdido development over the Great White field. Operator Petrobras is scheduled to start production from the Cascade/Chinook development in Walker Ridge in late 2010 with a ship-shaped floating production storage and offloading (FPSO) vessel.

A summary of the Paleogene discoveries can be found in Table 11. Paleogene hydrocarbons have been characterized as 22 - 41 API, 1 - 3% sulfur, 300 - 2,400 GOR (Landrum, 2007).

Table 11: List of Paleogene discoveries

Field / Area	Operator	Year of Discovery	Water Depth (ft)	Reservoir Depth (ft)	Initial Pressure (psi)	Temperature (F)
Trident (AC903)	Unocal	2001	9,721	16,097	8,675	132
Great White (AC857)	Shell	2002	8,072	14,518	7,028	165
Cascade (WR206)	Petrobras	2002	8,152	25,358	18,273	169
St Malo (WR678)	Unocal	2003	6,991	27,154	19,023	225
Chinook (WR469)	Petrobras	2003	8,831	25,600	18,447	166
Jack (WR759)	Chevron	2004	6,962	27,000	19,374	224
Tiger (AC818)	Chevron	2004	9,004	12,747	6,503	102
Silver Tip (AC818)	Chevron	2004	9,493	13,338	6,537	111
Tobago (AC859)	Shell	2004	9,493	17,348	9,487	109
Stones (WR508)	ENI	2005	9,571	26,826	19,196	199
Kaskida (KC292)	BP	2006	5,900	26,600	--	--
Julia (WR627)	ExxonMobil	2007	6,562	24,606	--	--
Hal (WR848)	Statoil	2008	7,657	--	--	--
Tiber (KC102)	BP	2009	4,155	30,900	--	--

6.3.2 Paleogene OOIP and Recoverable Oil

Chevron has stated: "This high-cost, high-potential, deep-water Wilcox trend has a potential ultimate reserve range of 3 to 15 BBOE …" (Lewis et al in "The Paleogene of the Gulf of Mexico and Caribbean Basins").

In mid-2007, Chevron made a presentation at the AAPG on the Lower Tertiary trend in which they stated that approximately 2.5 Billion BOE had then been found in the trend in 14 discoveries. They again gave the ultimate EUR for the trend as potentially 3 - 15 Billion BOE.

The low end of that trend suggests there may be few further discoveries, while the high end implies that future exploration would be highly productive. Chevron also stated that the industry had found 2 - 5 billion barrels of OOIP per discovery (Rains et al., 2007).

In 2008, the MMS estimated the discovered volume in the Lower Tertiary trend to be 2.8 billion bbl of producible hydrocarbons (MMS 2008-013, p. 8).

In the absence of much publicly available data for the Paleogene, an Ultimate Recovery Factor (URF) range can be estimated from various public statements: Chevron's estimate of 2-5 billion bbl OOIP per discovery; the Chevron/MMS trend EUR of 2.5 billion bbl Oil Equivalent; and the assumption that most of the recoverable volume of hydrocarbons will be oil, due to the relatively low reported GOR. That implied Ultimate Recovery Factor range is 4-9%.

A second approach to estimating a recovery factor for Paleogene discoveries is to apply the Arps correlation for reservoirs producing under a solution gas drive mechanism (Arps, 1968). This correlation was based on an extensive survey of fields reported by the American Petroleum Institute in 1967. Making some reasonable guesses at parameters for a "typical" Paleogene discovery, the Ultimate Recovery Factor calculated from the correlation is 8.9%.

Table 12: Arps correlation URF for hypothetical Paleogene field

Assumed Parameters for Paleogene	
Porosity (fraction)	0.2
Water saturation (fraction)	0.35
Oil formation volume factor (RB/STB)	1.5
Permeability (Darcies)	0.02
Reservoir oil viscosity (cP)	10
Bubble point pressure (psig)	3,500
Abandonment pressure (psig)	10,000
Correlation recovery efficiency (%)	8.9%

The minimum of the range of solution gas drive URFs in the data set reported by the API was 9.5%, showing that the low value calculated above was just below the bounds of industry experience.

A third approach is to estimate the recovery factor from the expected reservoir development process. It is unlikely that a Paleogene-type reservoir will produce below the bubble point by regular production, as shown in Figure 47. This implies the only energy for fluid production will come from fluid expansion and pore volume compressibility, which implies a low recovery factor. Using the Paleogene assumptions shown in Table 13, the estimate oil RF is 10% of OOIP.

The sector model of Paleogene was run to predict rate and recovery for primary production (Appendix A). The oil recovery prediction is 12% of OOIP. The oil rate quickly declines without production plateau (Figure 89). The simulation result shows that the peak oil rate is high but with large pressure draw-down (about 8,000 psi) because the initial PI is as low as about 1 STB/d/psi due to poor reservoir properties. The dominated drive mechanism is oil expansion.

Based on the three lines of enquiry – published statements, industry correlation, and expansion calculation and sector model simulation – we estimate a 10% recovery factor for the "Size of the Prize". The implied OOIP in discovered Paleogene fields in the DW GOM is 25 billion bbl, estimate recoverable oil 2.5 billion bbl, and ROIP 22.5 billion bbl.

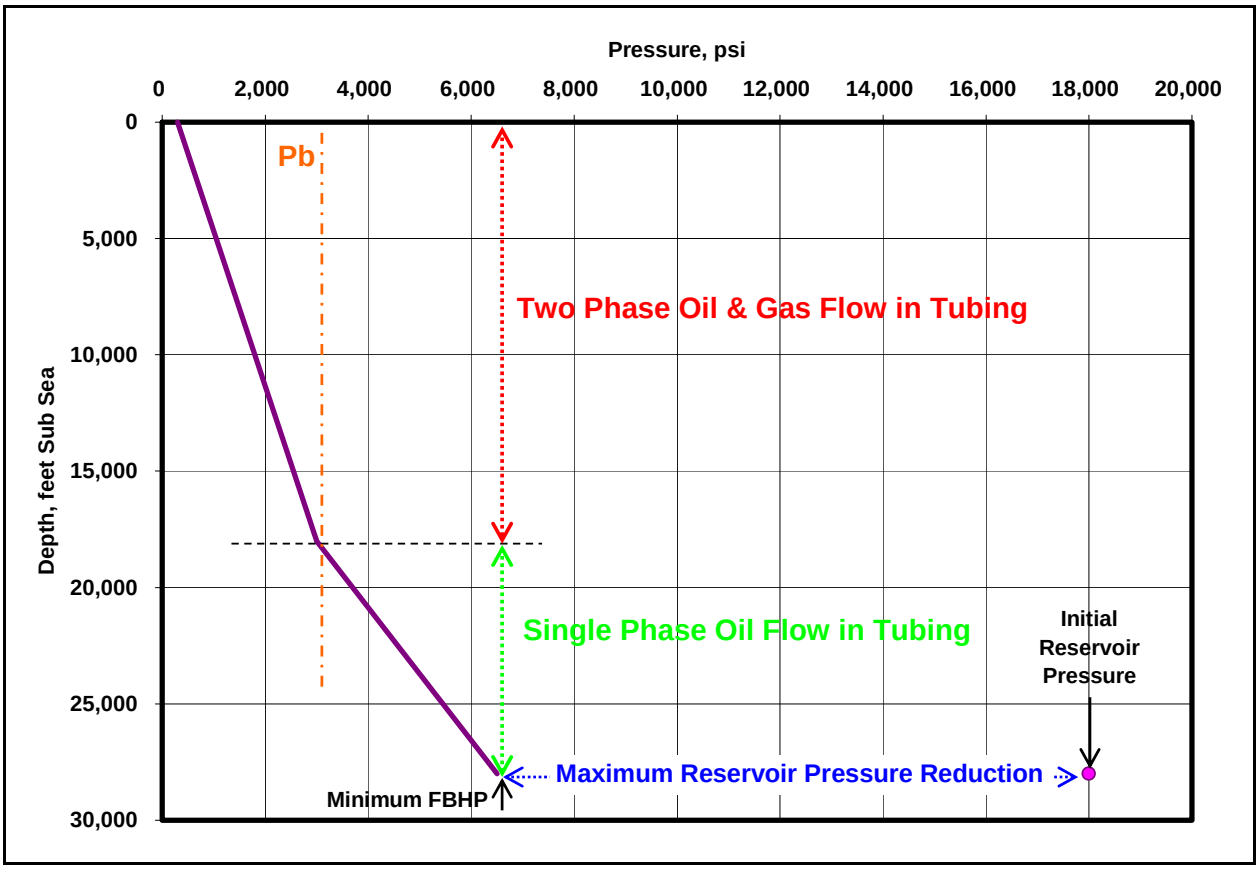


Figure 47: Hypothetical approximate Paleogene well pressure traverse

Table 13: Hypothetical Paleogene recovery by expansion

Assumed Parameters for Paleogene Production by Expansion	
Initial reservoir pressure (psi)	18,000
Minimum flowing bottomhole pressure (psi)	6,500
Maximum pressure drawdown (psi)	11,500
Average reservoir pressure drawdown (psi)	5,750
Reservoir oil compressibility (per psi)	15 E-06
Pore volume compressibility (per psi)	10 E-06

Water compressibility (per psi)	3 E-06
Average pressure system water saturation (%)	40%
Expansion recovery efficiency (%)	10%

6.4 *Summary of Discovered Oil "Size of the Prize"*

A summary of the OOIP, forecast ultimate oil recovery under current operating practices and ROIP target for improved oil recovery is shown in Table 14. The total discovered OOIP is 56 billion bbl, projected oil EUR is 12.3 billion bbl, and the remaining oil in-place target is 44 billion bbl.

Table 14: Summary of discovered OOIP, oil EUR and ROIP

	Neogene	Paleogene	Discovered Total
OOIP (billion STB)	31	25	56
Oil EUR (billion STB)	9.8	2.5	12.3
RF	31.6%	10%	
Remaining OOIP (billion (STB)	21	23	44

6.5 *Estimated Undiscovered Potential*

The MMS issued a National Assessment Brochure in 2006, incorporating data available as of 1 Jan 2003, in which they estimated a mean resource of 85.9 billion bbl of undiscovered technically recoverable oil in the Federal Outer Continental Shelf (MMS NAB). 44.92 billion bbl of this estimated undiscovered resource was in the GOM OCS region. All of the estimated undiscovered technically recoverable volume in the GOM was in water depths greater than 656 ft; thus, practically all of it was projected to be in deep water or ultra-deep water as defined in this study.

Out of the 44.92 billion bbl undiscovered oil which was assessed to be technically recoverable (i.e., regardless of economics), about 34 billion bbl was estimated to be the Undiscovered Economically Recoverable Resource (UERR) at an oil price of $40/Bbl.

There is obviously great uncertainty in the quantification of undiscovered volumes. The MMS did not reveal much about the methodology they had employed, stating only that:

"This assessment … considers recent geophysical, geological, technological, and economic information and utilizes a probabilistic play-based approach to estimate the undiscovered technically recoverable resources (UTRR) of oil and gas for individual plays. …. After estimation, individual play results are aggregated to larger areas such as basins and regions."

For comparison, the MMS estimated ultimate recovery (EUR) for the entire GOM Federal Outer Continental Shelf (shelf and deepwater) is 21.7 billion bbl oil in discovered fields ("proved" and "unproved"). The deepwater component of that discovered EUR was 9.8 billion bbl oil, of which 6.7 billion bbl oil remained to be produced at end-2004.

In the time since the MMS undiscovered resource estimate was made, about 2.5 billion bbl of recoverable Paleogene oil has arguably been added to the discovered volume, giving a DW

GOM discovered EUR of 12.3 billion bbl. By the same token, that 2.5 billion bbl of Paleogene discoveries should be deducted from MMS's 34 billion undiscovered resource, leaving 31.5 billion bbl still to be discovered.

Thus, the estimated 31.5 billion bbl recoverable oil in undiscovered deepwater fields should be compared with the 12.3 billion bbl recoverable oil in now-discovered deepwater fields. The MMS assessment thus implies that 2 ½ times as much recoverable conventional oil remains to be found in DW GOM as has already been discovered.

7 Trapped Oil Mechanisms

Prior to determining improved oil recovery processes it is important to understand the trapping mechanisms by which oil is being left behind. This will permit the screening of EOR/IOR processes into a prioritize list of those specific to the needs of the deepwater Gulf of Mexico. Separate trapped oil summaries are provided for the Neogene/Pleistocene and Paleogene groups of reservoirs.

As discussed in the prior chapter, the estimated average oil recovery for the Neogene and Paleogene are 31.6% and 10% respectively. Oil can be left behind in a reservoir due to a number of factors between the wellhead and the point of sale (i.e. premature abandonment of pipelines or facilities). However, in this work the trapped or remaining oil is evaluated only for reservoir mechanisms. The trapped oil mechanisms defined in this work are as follows:

- Non-communicating reservoir volumes
- Capillary bound or residual oil
- High abandonment pressure or low abandonment water cut
- Limited drive energy
- Poor sweep efficiency

7.1 *ROIP Distribution in Neogene Reservoirs*

7.1.1 Non-communicating Reservoir Volumes

Oil can be left behind in reservoirs because of compartmentalization due to faults or stratigraphic barriers. Oil in isolated compartments without a well has no pathway to the surface.

In a paper on Genesis field, authors from ExxonMobil pointed out there can be “dynamic” compartments as well as “static” compartments (Sweet, 2007). Static compartments have boundaries that were barriers to fluid flow over geologic time. Dynamic compartments have boundaries that were not barriers over geologic time, but impede flow sufficiently to have a significant impact on fluid contact movement or pressure depletion during production.

A “quick-look” exercise was made to estimate OOIP in areas not connected to wells. The study included 13 mature fields where detailed maps and logs were available. The specifics of the non-connected OOIP study are summarized as follows:

- The pilot study included 13 fields containing a total OOIP of 2.9 billion bbl
- The fields included 94 total fault blocks of which 41 fault blocks did not contain a well
- OOIP estimated in fault blocks without wells was 15% of the total
- All faults were assumed to be sealing – non-sealing faults and stratigraphic “dynamic compartments” within fault blocks were assumed to roughly offset each other
- It is assumed that the 13 fields reviewed are a good representation of the total OOIP for the Neogene/Pleistocene group of fields.

The average OOIP in an undrilled fault block in the 13 fields is estimated to be about 13 Million STB. It is difficult to justify targeting a $100 Million well at such a limited OOIP volume. Draining these smaller undrilled fault blocks will require innovations to provide much lower-cost reservoir penetrations.

Based on the 15% of OOIP estimate, the volume of ROIP in non-communicating reservoir is estimated to be 4.6 billion bbl.

7.1.2 Capillary-bound Residual Oil

One of the key mechanisms by which oil gets left behind in reservoirs is trapping due to interfacial tension forces between fluids and pore surfaces in reservoirs. This gives rise to the residual oil saturation (Sor) left behind in rock which has been thoroughly swept by a displacing fluid.

This irreducible residual oil saturation can be recovered in two ways:

- Further reduction in reservoir pressure. This will result in additional expulsion of oil from the pores due to fluid expansion and pore compression. The residual oil saturation will remain the same, but it will represent a smaller volume of the stock tank oil.
- Changing the interfacial tensions which hold residual oil in the pores. This requires displacing the oil with a different fluid, such as a slug of miscible hydrocarbons or injected water which has been enhanced with surfactants.

Based on proprietary data available to Knowledge Reservoir, the average value for residual oil saturation following displacement with water (Sorw) used in this study is 20% of reservoir pore volume. Using a typical average initial water saturation value for Neogene oil reservoirs, this corresponds to a capillary-bound residual oil of 25% of OOIP.

Table 15: Neogene residual oil as a percent of OOIP

Fluid and Reference Volume	Percent
Residual oil saturation as a percent of reservoir pore volume	20.0%
Average initial water saturation as a percent of reservoir pore volume	20.0%
Consequent initial oil saturation as a percent of reservoir pore volume	80.0 %
Neogene residual oil as a percent of initial oil saturation	25.0%

The 25% ROIP due to capillary bound fluid is corrected to apply to the portion connected to wells (85% of OOIP). It is also corrected for the recovery of residual oil which is recovered due to fluid expansion during reservoir depletions. Therefore, the forecast of remaining capillary bound oil connected to wells is [(0.25 x 0.85) – (0.25 0.85 x 0.067)] or 19.8% of connect OOIP.

Applying this value to the OOIP of 31 billion bbl, the total volume of capillary-bound residual oil in discovered Neogene DW GOM fields is estimated at about 6.1 billion bbl.

7.1.3 High Abandonment Pressure

The development of many Neogene reservoirs has not included artificial lift. Wells are projected to reach their economic limit with a relatively high bottomhole flowing pressure (BHFP). This is a

particular issue with subsea developments, where tubing head pressure (THP) may have to be several thousand psi to drive produced fluids for miles from the subsea wellhead to the receiving facility.

Reducing BHFP would lower the average reservoir pressure at abandonment, and thereby increase ultimate recovery. However, as a matter of good engineering practice, BHFP would normally be kept above the bubble point to prevent two phase flow of oil and gas in the near-wellbore region, which can significantly reduce a well's productivity index.

A very approximate estimate of the ultimate recovery factor (URF) benefit of applying a suitable form or artificial lift or THP reduction can be made from the simplified material balance compressibility equation:

Ct is the total system compressibility, and Δp is the incremental decline in average reservoir pressure from applying the artificial lift method. The possible value of Δp varies extensively from field to field. It could range from quite low values for some platform developments to ~4,000 psi for some subsea wells with high THPs. To be conservative, an average Δp of 1,600 psi is assumed for this GOM-wide exercise. Using a typical Neogene value for Ct suggests a reasonable target for incremental recovery of around 3% of communicating OOIP.

Table 16: Incremental recovery from artificial lift

Parameter	Value
Total compressibility (10-6 per psi) – fluid expansion and pore compaction	20
Incremental pressure drawdown, Δp (psi)	1600
Incremental ultimate recovery factor (% of OOIP)	3.2 %

Because artificial lift would have no effect on the reservoir pressure of isolated oil in non-communicating reservoirs, incremental recovery can come only from reservoir volumes which communicate with wells. Since 15% of the OOIP is estimated to be non-communicating, oil potentially recoverable through artificial lift is estimated at 2.7% of total OOIP.

ROIP in communicating reservoirs due to high abandonment pressures is thus estimated at about 1 billion bbl.

7.1.4 Limited Drive Energy and Poor Sweep Efficiency

A significant physical mechanism responsible for oil being left behind in the reservoir at abandonment is the absence of sufficient natural reservoir energy to drive oil from distant pores into the wells.

The natural reservoir energy in Neogene formations comes from rock compaction, aquifer influx and fluid expansion. There are two major mechanisms responsible for this potentially-displaceable communicating oil being left behind:

- Inadequate or absent fluid displacement drive mechanism or engineered fluid displacement.
- Poor volumetric sweep conformance where there is a fluid drive displacement mechanism.

The relative importance of those two trapping mechanisms clearly will vary substantially from reservoir to reservoir. To get a semi-quantitative estimate of the share of ROIP which might be left behind due to these mechanisms, a subset of DW GOM Neogene fields was selected.

These were oil fields for which sufficient data was available to provide an estimate of the projected ROIP at abandonment and of the cumulative water/oil ratio (WOR) as of April 2008. 49 oil fields were found with adequate data, with a combined 11.8 billion STB OOIP. This data is plotted in Figure 48.

Figure 48: ROIP in fields with no natural drive mechanism

Fields with a cumulative WOR of less than 0.1 were deemed to have no effective natural drive mechanism, i.e. natural aquifer influx was absent or inadequate. These fields are projected to hold about 57% of the ROIP of the set. Two-thirds of the fields fall in this category.

The remainder of the potentially-displaceable communicating ROIP volume was then ascribed to the poor volumetric sweep conformance mechanism. This trapped oil mechanism is caused by a variety of physical processes.

- Vertical bypassing
  - DW GOM fields tend to have complex geology, including multiple stacked sands with intervening non-reservoir intervals. Interconnections between the sands can be complicated. In addition, the individual sand bodies can have significantly different permeabilities. A classic example of vertical bypassing is the high permeability “thief zone” which takes all injection or natural influx water and causes the production wells to water out, leaving significant bypassed ROIP in less permeable sands.
- Areal bypassing
  - In a similar fashion to vertical bypassing, inject fluid or natural water drive tends to move along continuous higher permeability pathways, such as channel sands. This can leave significant parts of the reservoir unswept. Operator BP observed this phenomenon while injecting water into Horn Mountain field (Dixon, 2009).
- Well placement
  - Even where a relatively homogeneous reservoir benefits from a strong natural water drive or from water injection, the efficiency of areal sweep depends on well placement. In the course of field development, well locations must be chosen based on then-current incomplete knowledge of the reservoir. These locations may later turn out to be sub-optimal.

The particular causes for incomplete sweep are obviously highly specific to fields and reservoirs. Within the limitations of the data available, it is not practical to sub-divide the estimate of ROIP left due to incomplete sweep into the sub-categories noted above.

It should be noted that not all displaceable oil will in fact be displaced. Even where a volume of reservoir is thoroughly swept by an effective fluid displacement fluid mechanism, the physical process within the interconnected pores of a reservoir is not a perfect piston-like displacement. The displacing fluid breaks through into the production wells while a substantial amount of displaceable oil is still behind the flood front. This trailing oil can continue to be produced for as long as it is economic to produce a declining fraction of oil in the combined stream of oil and displacing fluid. The proportion of the displaceable oil left behind at the economic limit is a function of the reservoir fluid and rock properties.

7.2 *Summary of Neogene Trapped Oil*

In summary, the volumes of percentages of produced and trapped oil by the described mechanisms is shown in Table 17. The trapped and produced oil as a percentage of the discovered Neogene OOIP is shown in Figure 49.

Table 17: Summary of Neogene trapped in oil volume and percentage

	Oil (Billion STB)	% of OOIP
Total Neogene Discovered OOIP	31.0	100.0%
Forecast oil EUR	9.8	31.6%
Non-connected to wells	4.7	15.0%
High abandonment pressure	0.8	2.7%
Communicating capillary bound	6.1	19.8%
Limited displacement drive energy	5.5	17.6%
Poor sweep efficiency	4.1	13.3%

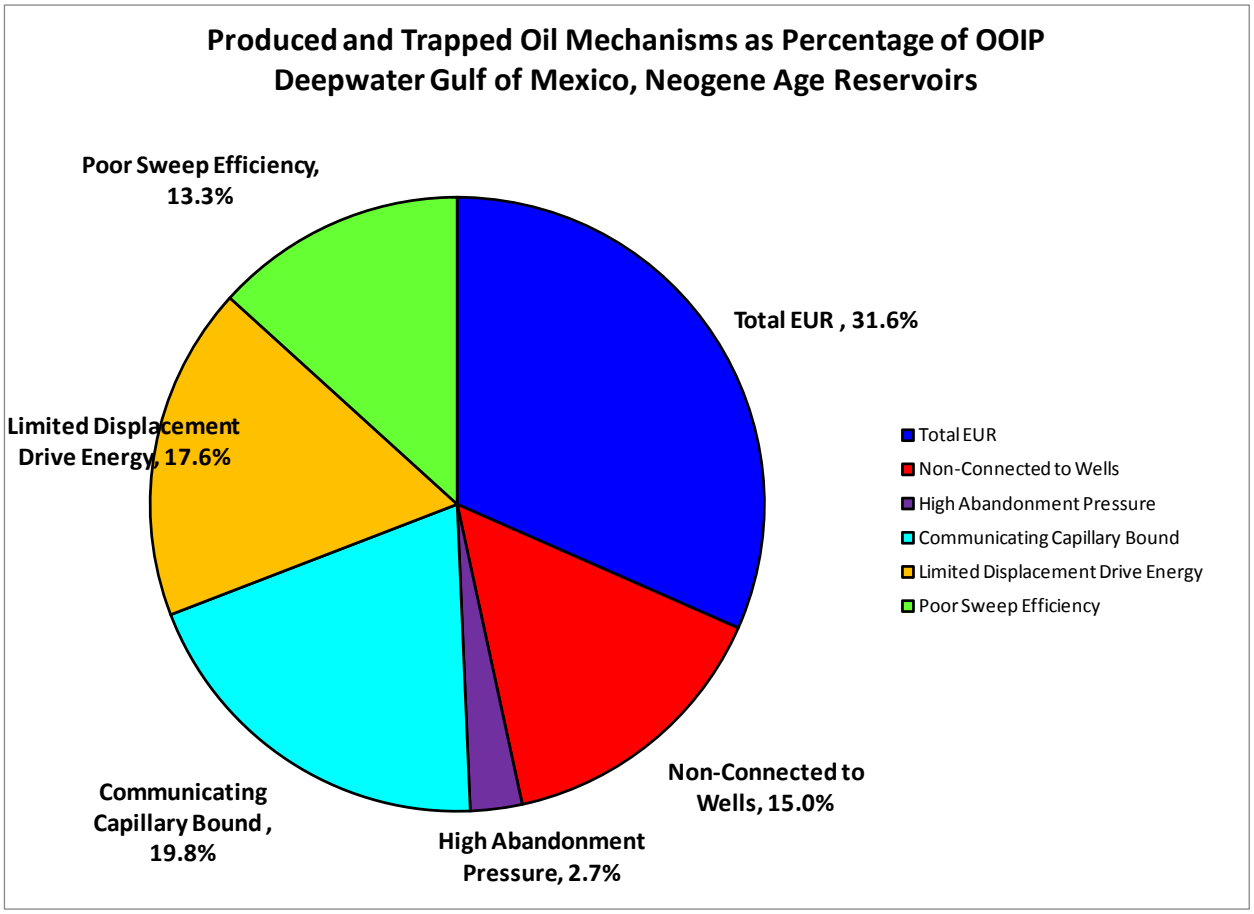


Figure 49: Neogene trapped oil pie chart, % of OOIP

7.3 *Paleogene Trapped Oil Summary*

A similar workflow was used to describe the expected trapped oil mechanisms for the Paleogene even though there is no producing experience and limited reservoir data is available. Below is a summary of the assumptions used for the estimation of produced and ROIP by category of trapping mechanism.

- Forecast oil EUR
  - As discussed in the “size of the prize” chapter, the estimated recoverable oil is 10% of OOIP assuming primary production and limited natural drive energy. Only primary recovery is assumed now due to the potential difficulties of secondary recovery methods in a low permeability reservoir which is vertically heterogeneous.
- Non-connected OOIP to Wells
  - With the lack of available data, the same volume of oil calculated as non-connected for the Neogene age reservoirs, 15% of OOIP has been used for the Paleogene.
- High abandonment pressure
  - Since the Paleogene is deeper and lower permeability, the potential lost recovery due to high abandonment pressures is more than for the Neogene. The

calculation of trapped oil due to high abandonment pressure is made using the assumptions of 25E-6 psi-1 for total compressibility and 3000 psi as the potential lowering of pressure. With the formula shown in 7.1.3, the calculated remaining oil target for high abandonment is 6% of OOIP.

- Capillary bound fluid
  - Where possible, publicly available data was used to estimate average initial water saturation for Paleogene age reservoirs. For residual oil saturation, the value used for the Neogene age reservoirs (Sor=20%) was scaled up to account for lower permeability and porosity rocks. For calculation of capillary bound ROIP is made using Swi = 24% and Sor = 28%. The resulting capillary bound oil is 36.8% of hydrocarbon pore volume (HCPV). This value is adjusted for the connected OOIP of 85% and for the reduction of residual oil by expansion in reducing abandonment pressure. Hence the capillary bound fluid is 36.8 x 0.85 x (1-0.06) or 29% of OOIP.
- Limited drive energy and poor sweep efficiency
  - The remaining OOIP not accounted for above is trapped due to limited drive energy and poor sweep efficiency. This equates to 100% (OOIP) - 10% (production) - 15% (non-connected) – 6% (high abandonment) – 29% (residual oil) or 40% remaining due to limited drive and poor sweep.
  - Again, data is not available like for the Neogene. Therefore an assumption was made to split 60% / 40% between limited drive and poor sweep. Both drive energy and poor sweep will be huge issues for the Paleogene and potentially the area that can be most affected by common IOR techniques. It is not important that these two be separated but only to recognize that they together represent a large IOR target.

In summary, the volumes of percentages of forecast production and trapped oil by the described mechanisms is shown in Table 18. The trapped and produced oil as a percentage of the discovered Neogene OOIP is shown in Figure 50.

Table 18: Summary of Paleogene trapped in oil volume and percentage

	Oil (Billion STB)	% of OOIP
Total Paleogene Discovered OOIP	25.0	100%
Forecast oil EUR	2.5	10%
Non-connected to wells	3.8	15%
High abandonment pressure	1.5	6%
Communicating capillary bound	7.2	29%
Limited displacement drive energy	6.0	24%
Poor sweep efficiency	4.0	16%

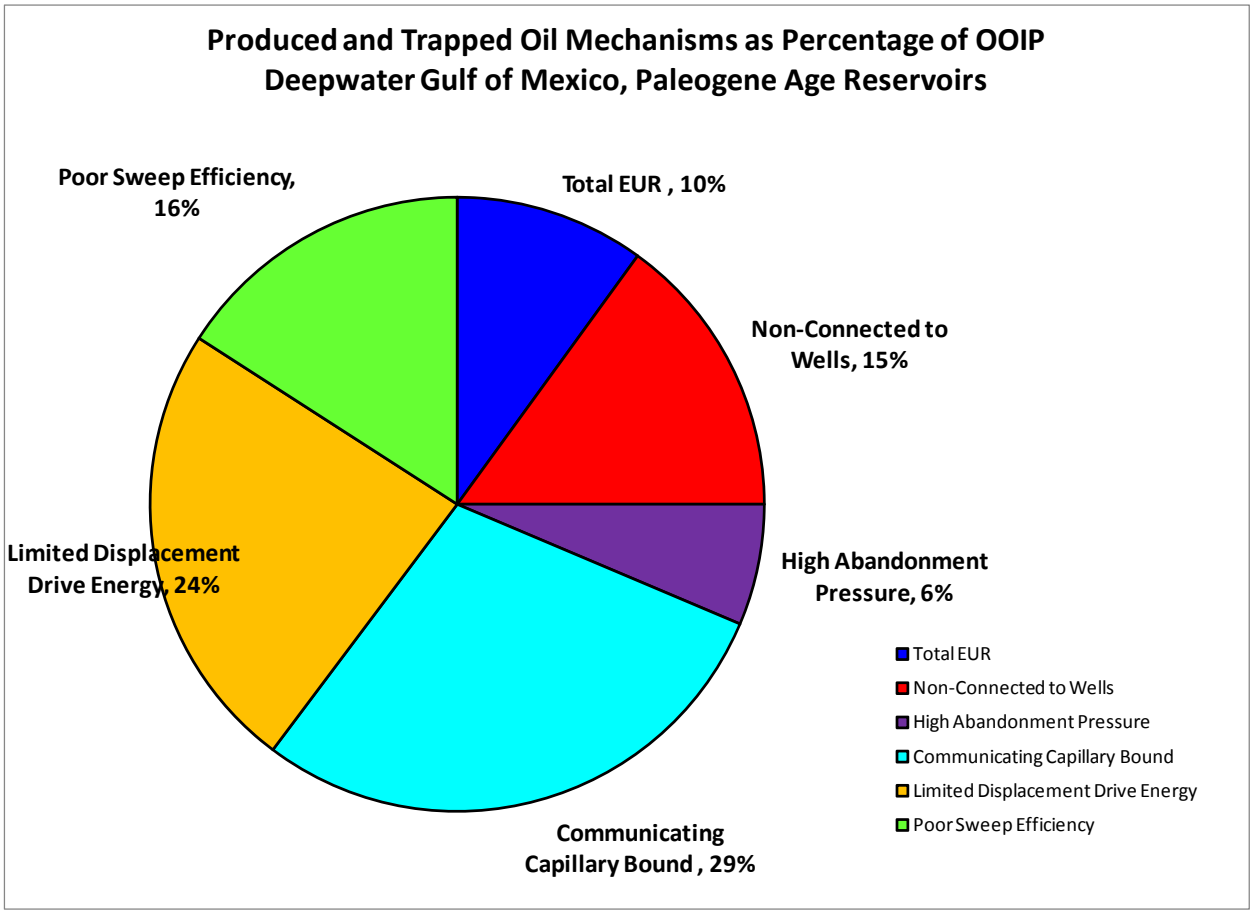


Figure 50: Paleogene trapped oil pie chart, % of OOIP

8 Improved Oil Recovery Concepts

Deepwater fields require the use of advanced technology for primary development, and often fields cannot be developed without the use of new equipment (Serial #1) designs. A good example is the recent startup of the Shell operated Perdido development in Alaminos Canyon which required a number of technological innovations.

The RPSEA 1701 study has a focus on reservoir development and the subsurface aspects of improving recovery since there is an enormous amount of other research currently in progress on wells, facilities, and subsea equipment. However, the wells and facilities are required enabling technologies and are also addressed in this work in terms of incremental recovery potential.

8.1 *Classification of IOR Processes under Consideration*

IOR, in the context of this discussion, signifies improved oil recovery by any means whether it be a field-verified reservoir process or an emerging idea on recovery improvement (Thomas, 2007). Increases in hydrocarbon extraction by mechanical methods and other operational strategies such as multiphase pumping systems, slant well completions, and water shut-off equipment may be thought of as enhancements to the base reservoir application but are nonetheless standard IOR technologies according to definition. Implementation timing is not a qualifying factor as any form of improved oil recovery can be initiated at different stages in the field development program. The deployment schedule, however, will be governed by an orderly execution of IOR operations.

Enhanced oil recovery (EOR) methods constitute a part of the general framework for IOR processes but are specifically distinguished as a subset of reservoir depletion strategies designed to lower residual oil saturation (Sor) below that attained by a conventional waterflooding application. Hence IOR processes targeting the release of capillary-bound oil remaining after a basic water drive are considered both IOR and EOR remedies for trapped oil. Low salinity water injection and, carbon dioxide or nitrogen flooding are classified as water-based and gas-based EOR, respectively.

Traditionally, the industry has interpreted conventional waterflooding as a secondary recovery option along with gas injection methodologies. Pressure maintenance operations utilizing water and gas as injectants are regarded as secondary methods while EOR is typically undertaken as a tertiary step following water and gas flooding applications. Primary depletion is normally tied to first oil shortly after project start-up yet the nature and sequencing of field development phases are not always clearly delineated.

Recovery by primary methods can vary from zero to over 50% depending on the intrinsic drive mechanisms and the hydrocarbon quality of a reservoir (Farouq Ali et al., 1996). Primary depletion methods applied to oil sands would invariably yield a recovery factor of 0%. Since oil sands and other viscous oil deposits show little to no secondary productivity, operators must adopt thermal EOR from project inception. Thermal exploitation of heavy oil, oil sands, and kerogen-bearing shale is one example of EOR efforts in the primary stage of field development rather than after the secondary phase.

IOR tactics are often adopted to support primary depletion where project economics cannot be favorably sustained outside secondary flooding measures. Offshore development plays are disadvantaged by a narrow window of opportunity for improving oil production. Factors contributing to deteriorating economics are the limited operating life of a platform and a recovery

process largely constrained by installed infrastructure, platform space, and logistics (Farouq Ali et al., 2000).

The cache of IOR methods has grown from a few root approaches to a complex catalog of modified standards and hybrid processes. An organization scheme for IOR methods is shown in Figure 51, an abbreviated version for the numerous, well-known recovery concepts. The three general classes of improved oil recovery are thermal applications, non-thermal methods, and production technology. Thermal techniques are dedicated to heavy oils of 15° API or less with viscosities of 1,200 cP or more. The principal categories of non-thermal methods are water drives, miscible displacement, chemical floods, immiscible gas drives, and advanced treatments such as microbial EOR (MEOR) and foam-assisted flooding. Oil production technology is a comprehensive set of mechanical methods for optimizing a given reservoir-based IOR process. Optimization techniques range from seismic imaging and conformance control to infill drilling and stimulation treatment. Production technologies relevant to deepwater exploitation are classified in Figure 52. Of the 24 individual IOR processes shown in the chart, only a few have proven commercial success. IOR development proposals carry inherent technical risks aggravated by costly operations.

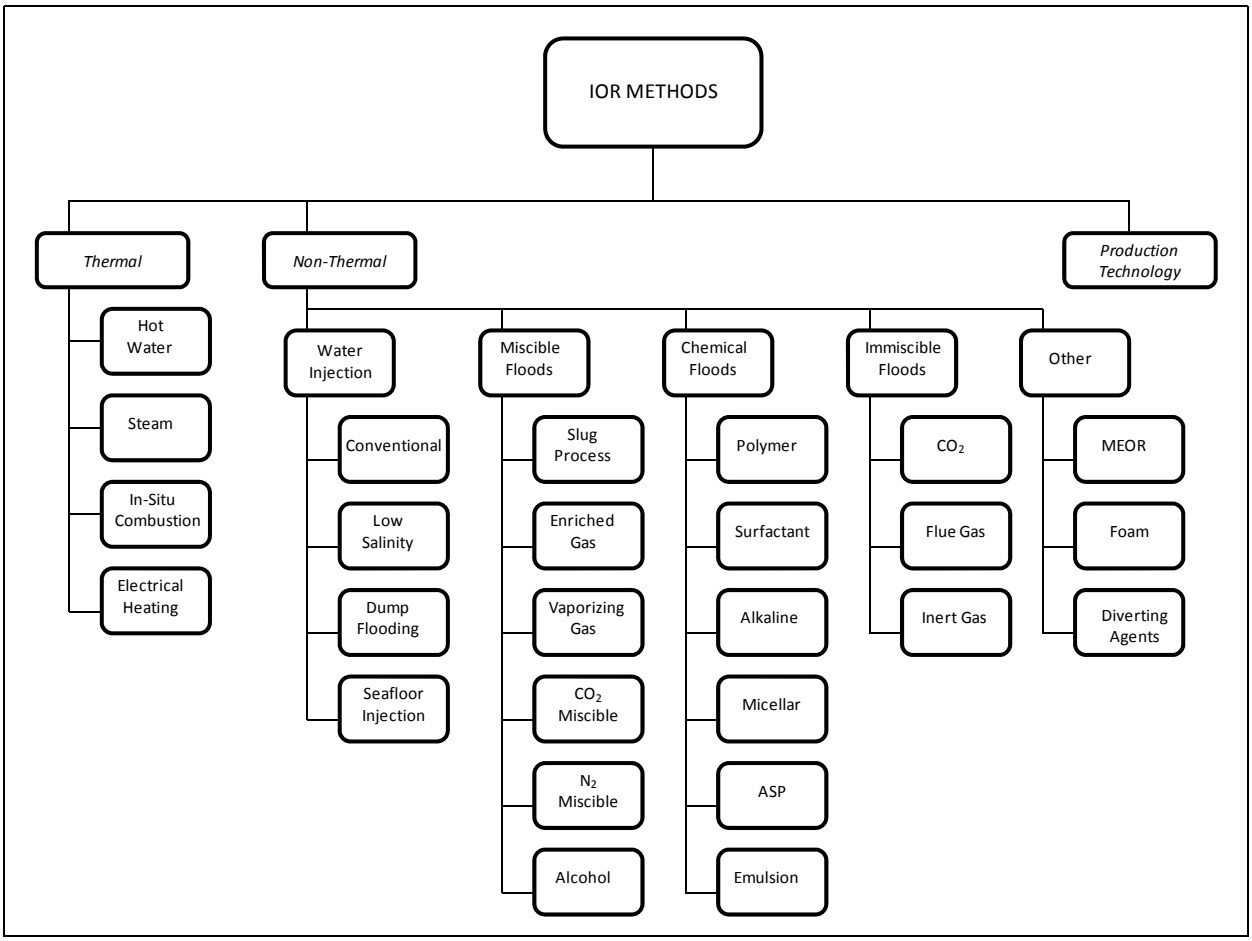


Figure 51: Classification of IOR methods (modified from Thomas, 2007)

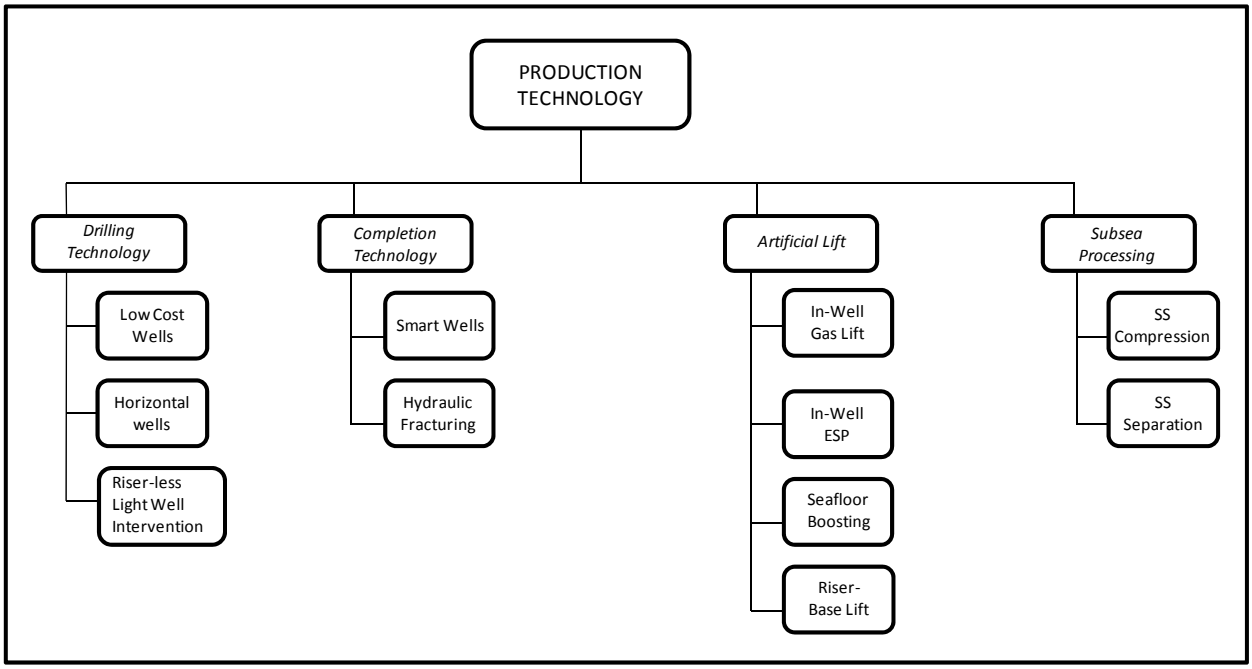


Figure 52: Classification of production technologies

8.2 *Worldwide Offshore IOR Experience*

Major offshore areas in the world have that have implemented IOR processes are the North Sea and Campos Basin, Brazil. The miscible or immiscible hydrocarbon gas and water-alternating gas injection methods have been widely applied in the North Sea to improve oil recovery due to limited gas export capacity. In the Campos Basin, waterflooding and water-based EOR were the most important IOR processes applied to improve viscous heavy oil recovery. Application of IOR processes have also been reported in offshore Malaysia developments.

8.2.1 North Sea

Water and gas injection were well established as oil recovery methods in the North Sea oil fields. Effective oil recovery has been observed from waterflooding because the water/oil mobility ratio is often favorable. The average recovery factor for waterflood on the Norwegian continental shelf (NCS) is some 45% and the target is to raise this recovery to 50% or more by IOR/EOR processes (Awan et al., 2008).

Enhanced oil recovery techniques have been employed in the North Sea since the 1970s. The five EOR technologies conducted in the region are hydrocarbon (HC) miscible gas injection, water-alternating-gas (WAG) injection, simultaneous water-and-gas (SWAG) injection, foam-assisted WAG (FAWAG) injection, and microbial EOR (MEOR). In the 30 years following adoption of improved oil recovery practices, 19 projects have been carried out. Apart from WAG at Ekofisk and FAWAG at Snorre central fault block, all technologies have been successful (Awan et al, 2008). Seafloor water injection and, subsea separation and boosting are implemented in the North Sea subsea tie-backs. Some enabling technologies, such as reservoir geophysics and fast model updating are under study. Future drilling and intervention concepts are put forward, including new generation well completions, improved well management, and real-time production optimization.

8.2.1.1 *Hydrocarbon Gas Injection*

Many hydrocarbon (HC) gas injection projects were initiated due to limited gas export capacities. Gas injection is also employed in gas storage or disposal projects. HC gas is injected to maintain reservoir pressure above the minimum miscibility pressure and to increase incremental recovery through miscible displacement. In order to improve the gas sweep efficiency for very heterogeneous North Sea reservoirs marked by high permeability streaks, updip injection was used to create a gravity-stable front driven by multi-contact miscibility in the Ekofisk (Jakobsson et al., 1994; Hermansen et al., 1997), Beryl (Steele and Adams, 1984; Grant, 1993; Cutt and Niznik, 2005), Stafjord (Buza and Unneberg, 1987; Haugen et al., 1987; Aadland et al., 1994), and Brent Fields (Broekers et al., 1986; Bath, 1987; Braithwait, 1994; Müller, 2005). However, downdip tertiary gas injection was used to displace the bypassed and capillary trapped oil in the waterflooded Brent reservoir of Alwyn North Field (Chaussumier et al., 1997; Burns et al., 2002) and the Smørbukk South Field (Jensen et al., 1999). The incremental oil for these projects is summarized in Table 19.

Hydrocarbon gas injection is a mature technology in the North Sea. N2 and CO2 injection have not been applied in the region because large volumes of low cost CO2 are unavailable and no pipelines exist to move the injectant. An OG21 study indicates CO2-EOR could provide a potential uplift of 3-7% OOIP on waterflooded North Sea reservoirs (TTA3, 2008).

8.2.1.2 *WAG Injection*

WAG is the most commonly used IOR technology in the North Sea, mainly downdip injection to help sweep the attic oil left behind after waterflood. Although there is no fixed injection pattern to realize best WAG strategy due to high offshore investment environment, the Statfjord field (Crogh et al) Brent reservoir WAG injection project used horizontal injectors to perforate deep in the formation for the gas to come into contact with more oil on its way up, and the producers were perforated and sidetracked in order to avoid excessive gas and water production. The optimum WAG ratio was reported as 1:1 in Gullfaks (Instefjord et al 2002), Brage (Lien et al. 1998) and Snorre (Christensen et al. 1998; Slotte et al. 1996). From those reports, the reasonable WAG length was 2-3 months under normal operational condition. It may also dependent on the availability of the gas. More gas injection happened in summer, less in winter on Gullfaks field (Instefjord et al. 2002). It was reported that WAG is sensitive to heterogeneity of reservoir. The incremental oil is summarized for six field projects in Table 19.

Table 19: HC gas injection and WAG projects summary

IOR Process	Field Name	Reservoir	Target OOIP (mmstb)	Predicted Incremental RF
Miscible gas injection	Alwyn North	Brent	597	3.30%
	Brent	Stratfjord	3793	1.40%
	Ekofisk	Ekofisk	6720	2-3%
Miscible WAG	Snorre	Stratfjord	3341	10-12%
	South Brae	Upper Brae	829	3%
	Magnus	MSM	1539	2-6%
Immiscible	Thistle	Brent-Tarbert	823	

WAG	Gullfaks	L-Brent	3655	8-10%
	Brage	Fensf	760	5%
	Ekofisk	Ekofisk	6720	3%
	Stratfjord	Brent	6280	7%
	Oseberg Ost	Brent	609	

8.2.1.3 *SWAG*

SWAG is applied when hydrocarbon gas volume is limited in field production and uneconomical to export from outside sources. Operating costs can be reduced since WAG conversions are no longer required and capital investment for surface equipment like gas compressors can be minimized. Statoil has implemented SWAG at Siri Field (Quale et al., 2000; Berge et al., 2002). From using SWAG at Siri, Statoil has reported incremental recovery of 6% compared to a water-injection scheme alone. However, the injection is more effective when one phase is injected at a time. The possibility of hydrate formation during SWAG injection is also a key issue in this type of hybrid flooding. A decrease in injectivity caused by two phases flowing around the wellbore is problematic in SWAG injection. Gravity may also contribute to water and gas separating quickly, leading to early gas breakthrough. SWAG appears a more challenging recovery technology than WAG.

8.2.1.4 *FAWAG*

There are two reported FAWAG field applications in the Snorre Field (Blaker et al., 1999; Skauge et al., 1999; Skauge, 2000; Aarra et al., 2002). FAWAG can potentially plug selected zones or layers with foam while the reservoir remains under WAG flood. Since more gas can be forced into less permeable or unswept areas, an improvement is realized from better gas sweep efficiency. The mechanism of foam injection in the overall process is not well understood.

8.2.1.5 *MEOR*

MEOR technology has been applied in the Norne Field (Sorhem et al., 1996; Hinderraker et al., 1996; Burger et al., 2005; Brown, 2002; Huges, 2002 & 2003; Brealey, 2003; NTNU, 2005). There are no reports on the Norne Field to explain the MEOR objectives, mechanisms, and measurable recovery improvement.

8.2.1.6 *Seafloor Separation and Boosting*

Subsea separation and boosting was first applied at the Troll-C pilot project, located in the NCS North Sea. Water depth is 1,116 feet. This technology was installed in 1999, but was not put into service until separation and injection operations began in August 2001. Subsea boosting operations did not commence at Troll-C until late 2005, when a centrifugal booster pump was installed on the oil leg of the separator (no gas). However, the well(s) ceased to produce on their own in 2003, prompting the subsequent booster pump installation.

Statoil (formerly Hydro) deployed a similar subsea separation, boosting, and injection (SSBI) station in 690 feet of water at the Tordis Field in the NCS North Sea. This project was installed in 2007, when separation and injection operations came onstream. The Tordis SSBI is significantly larger than its Troll-C predecessor. Unfortunately, re-injection of produced water (and sand) in the Tordis project ceased after only one month, when the injection zone could no longer take water (E&P Magazine, March 2010). The facility is operating, but only as a booster

station pumping oil and water back to the Gullfaks C platform. Statoil is now evaluating options to either add a new injection well or increase the water handling capacity of the Gullfaks platform.

8.2.1.7 *Seafloor Water Injection*

Columba Terraces, the first seafloor water injection plant, is located adjacent to the south-west extent of the Ninian Field, northern North Sea. The water depth is 435 feet. The field was placed on production in May 1998. Water injection did not begin until June 2003. The seafloor water injection system was designed with subsea electric centrifugal pumps to deliver seawater to injectors, a filtration package, and high speed controls. Operation was initiated in June 2007. The subsea injection system was 5 miles from the host and the unit could deliver the necessary volumes at much higher pressure than the current topsides facilities. Incremental oil benefits have not been reported.

8.2.2 Brazil

Of the 55 fields operating in the Campos Basin, 36 are considered mature (Figure 53). Most production is from reservoirs with relatively low API oil of 19-22˚ and in-situ viscosities of 6-8 cp. Many heavy oil reservoirs have been discovered in water depths between 3,500 and 8,500 feet. Oil gravities are in the 11 to 19 ˚API range. Several deepwater projects are in operation. Water depths are 3,500 to 8,500 feet and API grade for crude oil is 14˚ to 30˚. Permeability for reservoir sands is 5 to 10 darcies (Minami et al., 2003).

Development strategies for the deepwater reservoirs rely heavily on water injection. It is reported that the depletion recovery factor for Marlim field is 12% and 38% after waterflooding. Water injection is critical for maintaining production in this very large, 6.4 billion barrel oilfield with 102 producers and 50 injectors. At the end of 2006, nineteen offshore water injection projects will be active or in the planning phase. Aggregate injection for these reservoirs is projected at 3,145,000 bwpd. Horizontal subsea wells with open-hole completions are used successfully to increase water injection potential and sweep efficiency (Shecaira et al., 2002).

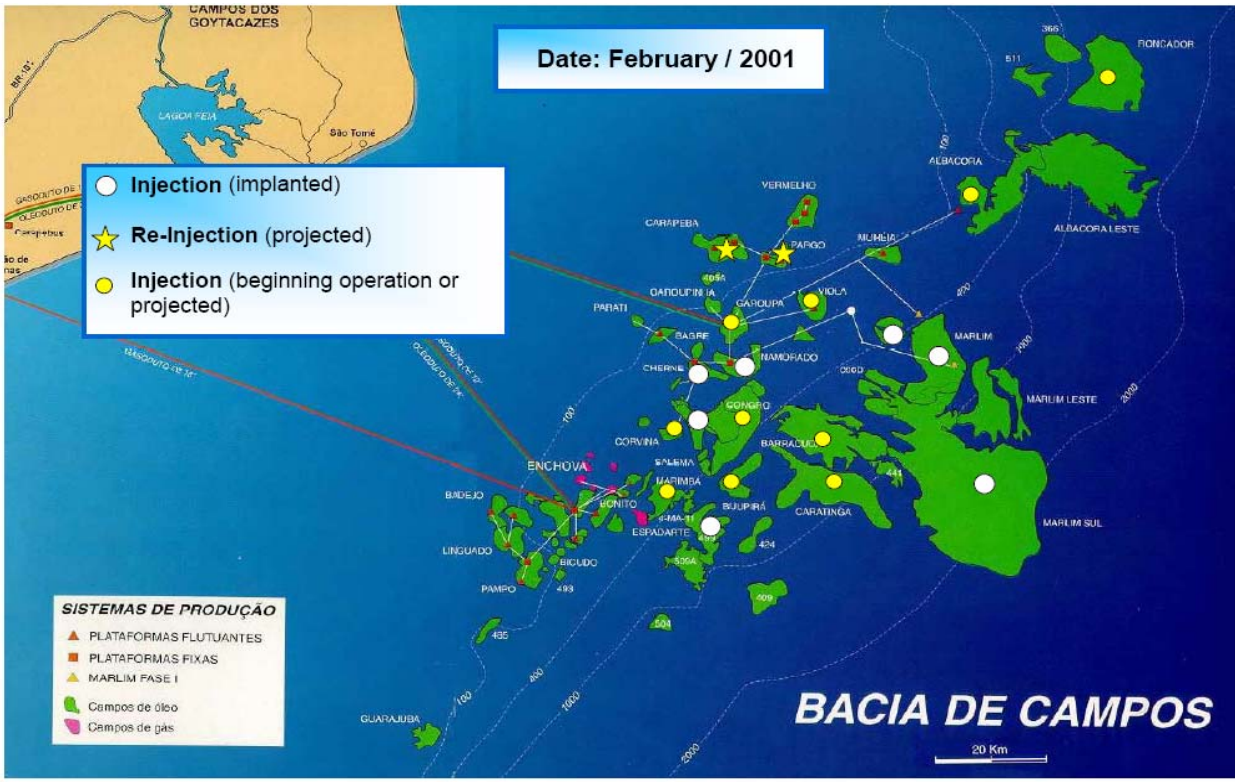


Figure 53: Water injection in Campos Basin

Moreover, most Petrobras deepwater fields are developed with subsea infrastructure. Alternative cost-efficient EOR methods capable of sweep efficiency improvement have been sought by the operator. Seafloor water injection, subsea oil-water separation, dump flooding, and chemical additives are of special interest and could likely be implemented using existing facilities and within the relevant timeframe.

8.2.3 Malaysia

Seafloor water injection at Barton Field offshore Malaysia was installed because of its small size and marginal economics for a new water injection platform. An IOR potential of 6% of OOIP has reported. The combination of microbial EOR effect uses naturally-occurring bacteria which feed on carbon and nutrients provided by nitrate, oxygen, and phosphates (Flatval et al., 2004).

9 IOR Potential in Neogene Age Reservoirs

The evaluation of oil trapping mechanisms provides insight into the reasons for forecasted remaining oil in Neogene and Pleistocene age reservoirs. There is obviously a broad cross-section of reservoir performance, as pointed out in Section 6.1.1, but the objective is to define specific IOR concepts which can target the trapped oil.

The trapped oil categories for Neogene age reservoirs are shown in Figure 54 along with IOR concepts. Reservoirs with limited or no displacement drive and poor sweep efficiency are targets for water or gas injection. Capillary bound fluid which accounts for about 20% of the expected remaining requires the injection of water-based or gas-based fluids to reduce interfacial tension and reduce residual oil saturation. The deepwater GOM is in the early stages of the development life-cycle and therefore EOR processes to capture this remaining oil wedge are for the most part a more distant recovery target.

As Figure 54 shows, well technology is required for all the IOR processes, not only for targeting the “Non-Connected to Wells” portion of remaining oil. Wells and pumping/artificial lift are enabling technology since the economics for any incremental deepwater project are tied to cost-effective and reliable wells and completions.

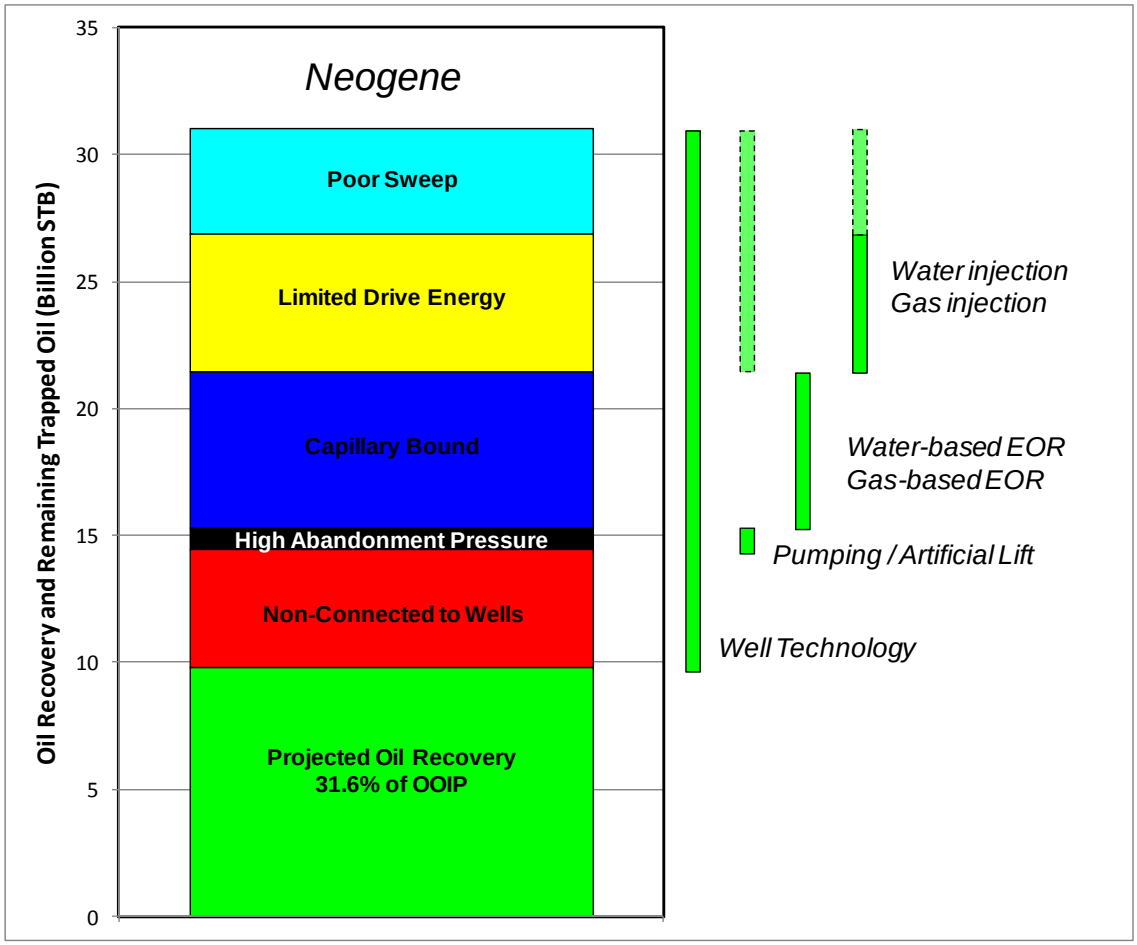


Figure 54: Neogene trapped oil and IOR concepts

9.1 *Selection of IOR Processes*

Many improved and EOR processes are available to the industry and have been tested in onshore fields. More limited experience exists for offshore and far fewer IOR methods have been used in deepwater fields.

The basin with the most offshore experience of IOR/EOR implementation is the North Sea. The North Sea experience is primarily in enhancing waterflooding with gas injection, limited enriched miscible gas injection, recent microbial enhanced recovery (MEOR), extended reach and horizontal drilling, recent seafloor water injection, and artificial lift. Many of the North Sea joint industry project initiatives have been reviewed as part of evaluating potential for the deepwater GOM.

Figure 51 and Figure 52 show categories of improved oil recovery alternatives. Thermal methods are not considered due to the water and reservoir depths and the lack of low API, highly viscous oils.

As highlighted above, the injection of water or gas to provide reservoir energy has significant potential. Consequently, both water and gas-based EOR processes have potential assuming injection wells are used for secondary recovery. A summary of the Neogene IOR processes selected for evaluation are shown below. Specific water injection schemes, dump flooding and seafloor water injection, which are included as low-cost alternatives. As noted earlier in this report, there are many small reservoirs and remote subsea tie-backs for which conventional water injection with surface injection equipment is not an option.

- Water Injection
  - Conventional
  - Dump flood
  - Raw seawater
- Water-based EOR
  - Low salinity water injection
  - MEOR
  - ASP
  - Other chemical
- Gas Injection
  - Hydrocarbon gas
  - Gas dump flood
- Gas-based EOR
  - Nitrogen
  - CO2
- Diverting agents
  - Smart chemical treatments
- Pumping and Lift
  - Multiphase pumping
  - Gas lift
  - ESP
  - Subsea processing

- Well technology
  - Low cost wells
  - Low cost intervention
  - Horizontal drilling

Hydrocarbon gas injection has been used world-wide typically in basins where the economics of gas transportation, sales, and/or liquefaction and sales is poor. The Gulf of Mexico has a robust pipeline and gas sales market which has traditionally been a disincentive for gas injection. However, for this study it is still included as an alternative. An additional gas injection process, gas dump flooding is included where a gas reservoir existing above or below the oil zone of interest is used to dump gas for IOR through a designated wellbore. The technique is unproven as a reservoir gas-drive process but has been applied for gas lifting wells.

Water-based EOR methods include two options which potentially are low cost for implementation, low-salinity water injection (LowSal) and microbial enhanced recovery (MEOR). Both LowSal and MEOR are proven concepts but with high risk due.

9.2 *Review of Neogene IOR Processes*

A total of 19 IOR processes are included on the list for review of applicability and potential in Neogene age reservoirs. The working committee and project team refined the IOR process list over several months and during the process of evaluation.

The field experience of each IOR process was reviewed as part of the evaluation. In particular, the technical incremental recovery and technical readiness factors are based on analog field experience. The number of deepwater GOM field targets is defined using the database of field and reservoir information and selected criteria reflecting drive mechanisms and forecast oil recovery.

9.2.1 Conventional Water Injection

The definition of conventional water injection is that facilities for the supply and treatment of water for injection are located on surface facilities. It includes both dry and wet tree development wells. Water injection in offshore fields is mature particularly in facility and well technology. The waterflooding of turbidite reservoirs in deepwater is less mature, and the understanding of reservoir connectivity and sweep efficiency is continuing to evolve.

The influence of complex, channelized turbidites on water injection performance is reviewed in detail for the Schiehallion field, West of Shetlands (Davey, GCSSEPM 2008). The evaluation of Schiehallion is aided by 4D seismic where fluid movement and pressure changes can be tracked during the water injection history. Production data indicated poor connectivity between reservoir depositional elements which requires a very high injector to producer ratio of 1.1 (22 producers, 24 injectors). Operator BP recognized, with 4D seismic, complicated water break-through patterns and pressuring downdip of injectors. Well logs also show significant geologic complexity at sub-seismic scale. The forecast recovery is 25 – 30% (500 – 600 MMSTB of the OOIP of 2000 MMSTB), an estimated 10 – 15% incremental over primary recovery.

Seismic imaging is less reliable in the deepwater Gulf of Mexico, as compared to the North Sea, West Africa, and Brazil, due to deeper reservoirs and salt tectonics. There is waterflooding experience in 12 DW GOM to use as a direct analog for future projects. The fields with water injection are Petronius (J1 and J2 sands), Mars (N/O, M1/M2, and E sands), Ursa (N/O sand), Horn Mountain (M Sand), Princess (N/O sand), Morpeth (M-2/P sand), Amberjack (G sand),

Ram Powell (N sand), Pompano (M83-85 sand), Bullwinkle, Lena, and Holstein (J2 and J3 sands).

Water injection commenced near the start of production in Petronius, Lena, Horn Mountain, and Holstein fields, and considerable water has been injected. The Amberjack (2 yr), Bullwinkle (4 yr), Ram Powell (2 yr) and Morpeth (4 months) fields have had only short periods of water injection. Water injection was halted in these projects due to insufficient reservoir benefits for continuing. Six years of injection occurred in the Pompano Miocene (M83-85) reservoir, but this appeared to mainly a disposal project more than a secondary waterflood. The Mars, Ursa, and Princess fields are examples where primary production was followed by the start of water injection after the initial, high reservoir pressure was reduced.

Several of the Gulf of Mexico deepwater waterflooding projects are reviewed in more detail below.

9.2.1.1 *Petronius Field*

The Petronius field is located in Viosca Knoll 786 and production commenced in 2000. Chevron is the operator of the field and holds 50% interest; Marathon Oil holds the remaining 50% interest. The J1 and J2 reservoirs are Miocene sheet sands (Figure 55). Waterflooding commenced 7 months after start of production and pressure response was observed almost immediately. The J1 and J2 are only slightly over-pressured (pressure gradient < 0.50 psi/ft), and the J1 sand contained an initial free gas cap (Table 20). The initial conditions required that water injection be part of the base development plan.

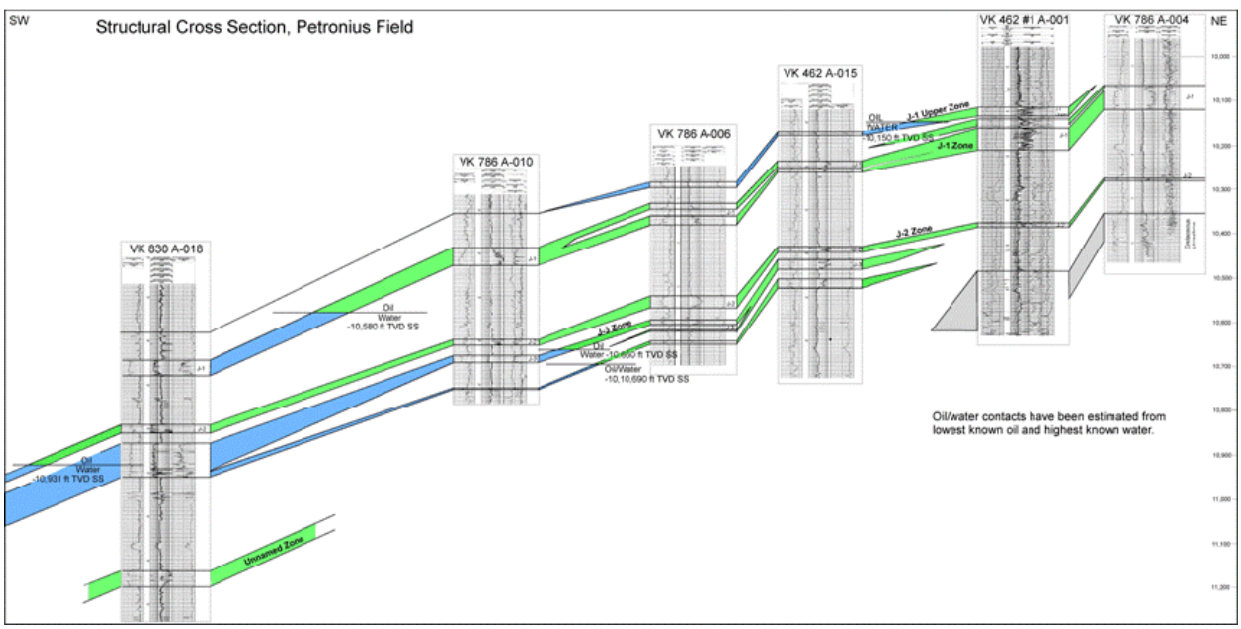


Figure 55: Petronius field structural cross section

J1 sand production performance is displayed in Figure 56. Production (6 wells) and injection (2 wells) were stable for a number of years until decline from increasing water cut indicating good reservoir connectivity. The operation uptime of injection equipment is high, and there appears to be no issues with decline well injectivity.

Table 20: Petronius J1 and J2 Sands reservoir properties

Reservoir Property	J1 Sand	J2 Sand
Area (acre)	2,670	3,551
Completion(s)	6 producers, 2 injectors	5 producers, 2 injectors
Permeability (mD)	490	398
Net/gross Sand	0.86	0.91
Thickness (ft)	36	19
Average Porosity	0.28	0.31
Water Saturation, Swi	0.21	0.24
Initial Oil FVF (rb/sfb)	1.3	1.4
Datum Depth (ft)	10,100	10,650
Initial Pressure @ datum (psia)	4,820	5,303
Bubble Point Pressure (psia)	4,250	4,879

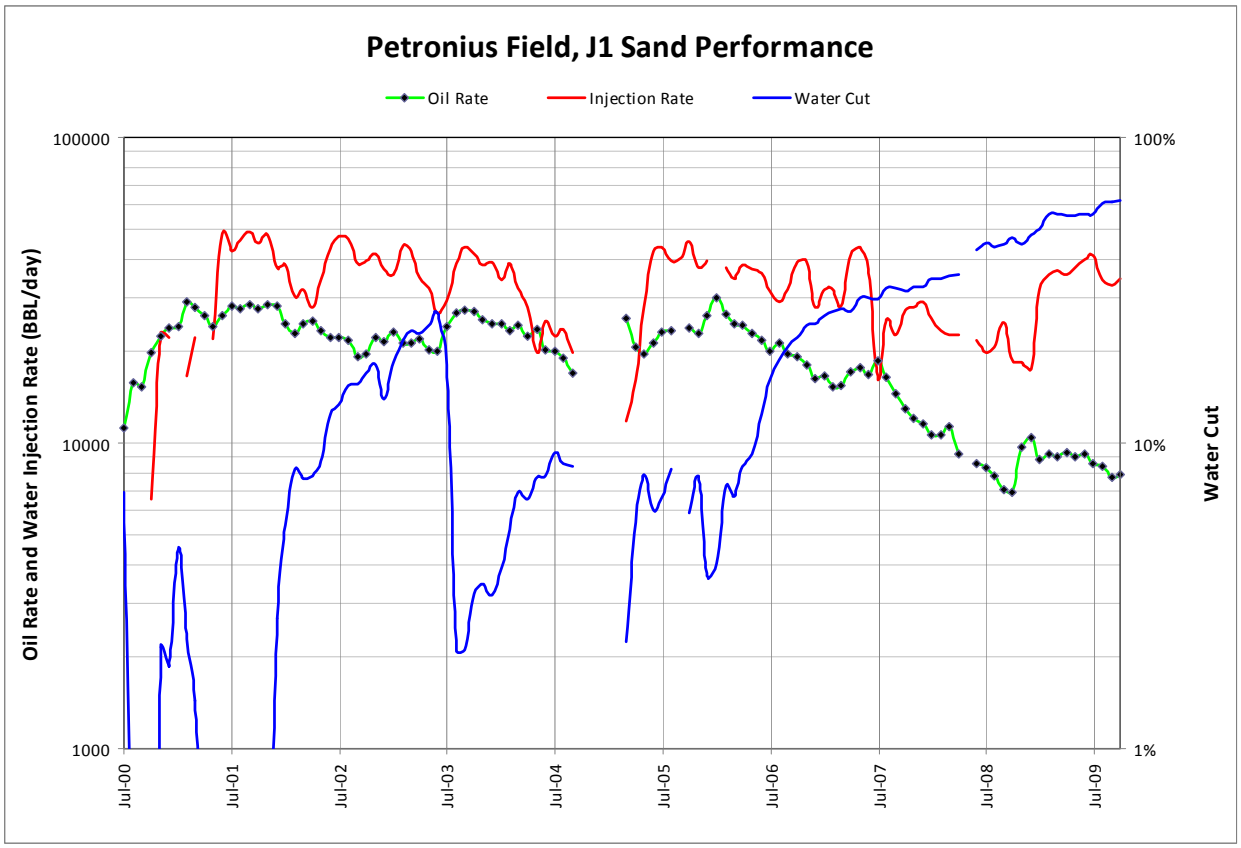


Figure 56: Production and injection history of Petronius J1 sand

The waterflood is mature giving confidence in prediction of ultimate recovery by decline curve. The ultimate recovery factors of J1 and J2 reservoirs are expected as 57% and 54%,

respectively. The recovery factors without injection were estimated by material balance for the estimation of incremental recovery. The estimated depletion recovery factors for J1 and J2 reservoirs were 20% and 28% from moderate rock compaction, minor aquifer influx and solution gas drive energy. Therefore, the incremental oil recovery by waterflooding is estimated at 37% and 27% of OOIP (Table 21).

Cumulative water injection is 99 MMSTB and 69 MMSTB (Oct. 2009) representing 55% and 45% of pore volume for the J1 and J2 respectively. The incremental oil is 0.40 and 0.29 STB for every 1 Bbl of injected water for the J1 and J2 reservoirs respectively.

There are no reported issues with wells, completions, scaling, souring, corrosion, or other production problems from operator. The Petronius waterflood appears to be highly successful.

Table 21: Petronius J1 and J2 sand waterflood performance

Volumes and Recovery	J1 Sand	J2 Sand
Original oil in place (MMSTB)	109	80
Solution gas in place (BSCF)	75	70
Cumulative oil Oct. 2009 (MMSTB)	59	42
Cumulative gas Oct. 2009 (BSCF)	55	41
Cumulative water injection Oct. 2009 (MMSTB)	99	69
Depletion oil EUR (MMSTB)	22	22
Depletion gas EUR (BSCF)	12	17
Depletion oil RF	20%	28%
Depletion gas RF	16%	24%
Waterflood oil EUR (MMSTB)	62	43
Waterflood oil RF	57%	54%
Waterflood IOR	37%	27%

9.2.1.2 *Mars Field*

Production in Mars field (Mississippi Canyon 762, 763, 807, 850 and 851) began in 1996 and hit peak oil rate in June 2000 at 208,000 STB/d of oil and 217 MMSCF/d of gas. Current cumulative production is 600 MMBOE. It is expected to produce another 600 MMBOE for 1200 MMBOE EUR. Remaining exploitation plan is for another 50 years of production. It is developed by a 24-slot TLP, and it is reported that a second new TLP is under construction to add wells and processing equipment. Shell has 71.5% interest and BP has the remaining 28.5%.

The Mars field consists of a series of Miocene to Pliocene age turbidites sands deposited within a minibasin bounded by the deeply rooted Venus salt body to the southeast and the more tabular Anatares salt body to the north and west (Figure 57). There are 14 major reservoirs and 10 minor zones. Mars field is a prime candidate for secondary recovery since the reservoirs have limited aquifer influx, were highly over-pressured and highly compacting, and were highly under-saturated. Also, the reservoirs are characterized by good vertical and horizontal permeability, good structure relief, and good connectivity.

Mars field is a good analog for the case of late-life water injection after significant depletion in a highly compacting rock. The waterflood objectives are to stabilize reservoir pressure and not to increase it; to prevent the M1/M2 (Upper Green) and E (Pink) sands from producing below their bubble points; and to minimize well completion failures from compacting reservoirs.

The seawater injection commenced in 2004 into 3 reservoirs, N/O (Yellow) sand, M1/M2 (Upper Green) sand, and E (Pink) sand by three injectors (A12, A16 and A18). The current water delivery is 82,000 bwpd with a 7-stage centrifugal pump and discharge pressure of 6850 psi. It is still early in the performance of these waterfloods, and projections are preliminary. Cumulative injection was 46 MMBbl at June 2009. Response has been observed in offset wells but no significant water break-through has occurred.

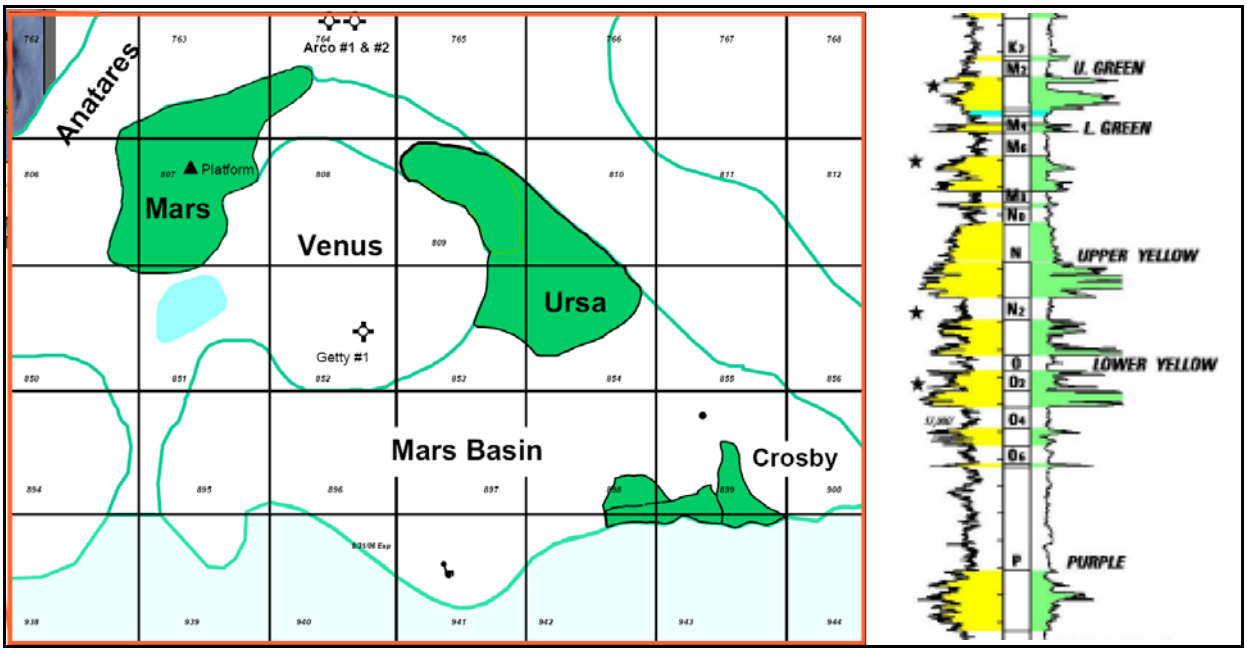


Figure 57: Mars basin and salt structures (Reynolds, 2000) with type log (Meckel, 2002)

Properties for the three waterflooded reservoirs are shown in Table 22. The N/O sand, also called the Yellow sand, is reviewed in detail as an example of how incremental oil from water injection has been estimated. The O sand (Lower Yellow) are generally characterized as sheet sands while the N sand (Upper Yellow) is comprised of channelized deposits. Massive fine and very-fine grained sands are observed. The sheets display excellent lateral pressure communication. The internal zone shales do not compartmentalize the reservoir as observed from pressure and production history.

The N and O1/O2 sands are the major reservoirs in Mars field. There are six producers (764-4ST1, A2, A3, A6, A17 and A21) and currently only one injector (A16) in the zone (Figure 58). Historical production and injection for the N/O sand is shown in Figure 59. Natural aquifer influx is negligible as observed from pressure history and the minor water production prior to injection.

Table 22: N/O, M1/M2 and E sands reservoir property summary

Reservoir Property	N/O Sand (Yellow)	M1/M2 (Upper Green)	E (Pink)
Area (acre)	4,917	3,715	6,049
Completion(s)	6 producers, 1 injector	3 producers, 1 injector	2 producers, 1 injector
Permeability (mD)	125	171	272
Net/gross Sand	0.9	0.93	0.95
Thickness (ft)	99	106	34
Average Porosity	0.28	0.20	0.26
Water Saturation, Swi	0.22	0.26	0.24
Oil Initial FVF (rb/stb)	1.39	1.2	1.3
Datum Depth (ft)	16,726	16,237	11,851
Initial Pressure @datum (psia)	11,305	11,007	7,410
Bubble Point pressure (psia)	6,306	5,413	4,485

Water injection commenced in 2004 when reservoir pressure was about 6,800 psia, approximately 4,500 psi below the original 11,305 psia. The layout of reservoir development wells is shown in Figure 58. Approximately 20 million barrels of seawater have been injected to date representing only 0.02 of total pore volume. Injection system uptime has been affected by hurricanes, pump downtime, and well completion issues. However, the productivity index (PI) of well A2 has improved due to injection as reported by Weiland, et al (2008). The N sand completion PI was improved from 13.5 bbl/day/psi in 2004 to 21.8 in 2005 while the separate O1/O2 sand completion PI improved from 47 bbl/day/psi to 55.6.

A summary of the estimated depletion and waterflood recoveries for the N/O sand and the other reservoirs with active secondary recovery is shown in Table 23. It is not possible to establish waterflood recovery by decline analysis. Therefore, a cross-sectional simulation model has been used to predict the incremental. The forecast depletion oil RF was matched to tune the model for input of rock compressibility, fluid properties, and natural aquifer influx. The model was then used to estimate oil recovery for a range of injected volumes. The assumption is that future additional injectors will be added by the operator since early evidence suggests that the waterflood is effective.

The waterflood recovery factor of 56% is estimated for all zones. Since less is known about the M1/M2 and E sands, the water injection IOR is more tentative. Therefore, the forecast waterflood IOR of 26% in the N/O sand is considered the best estimate for reservoirs in Mars field.

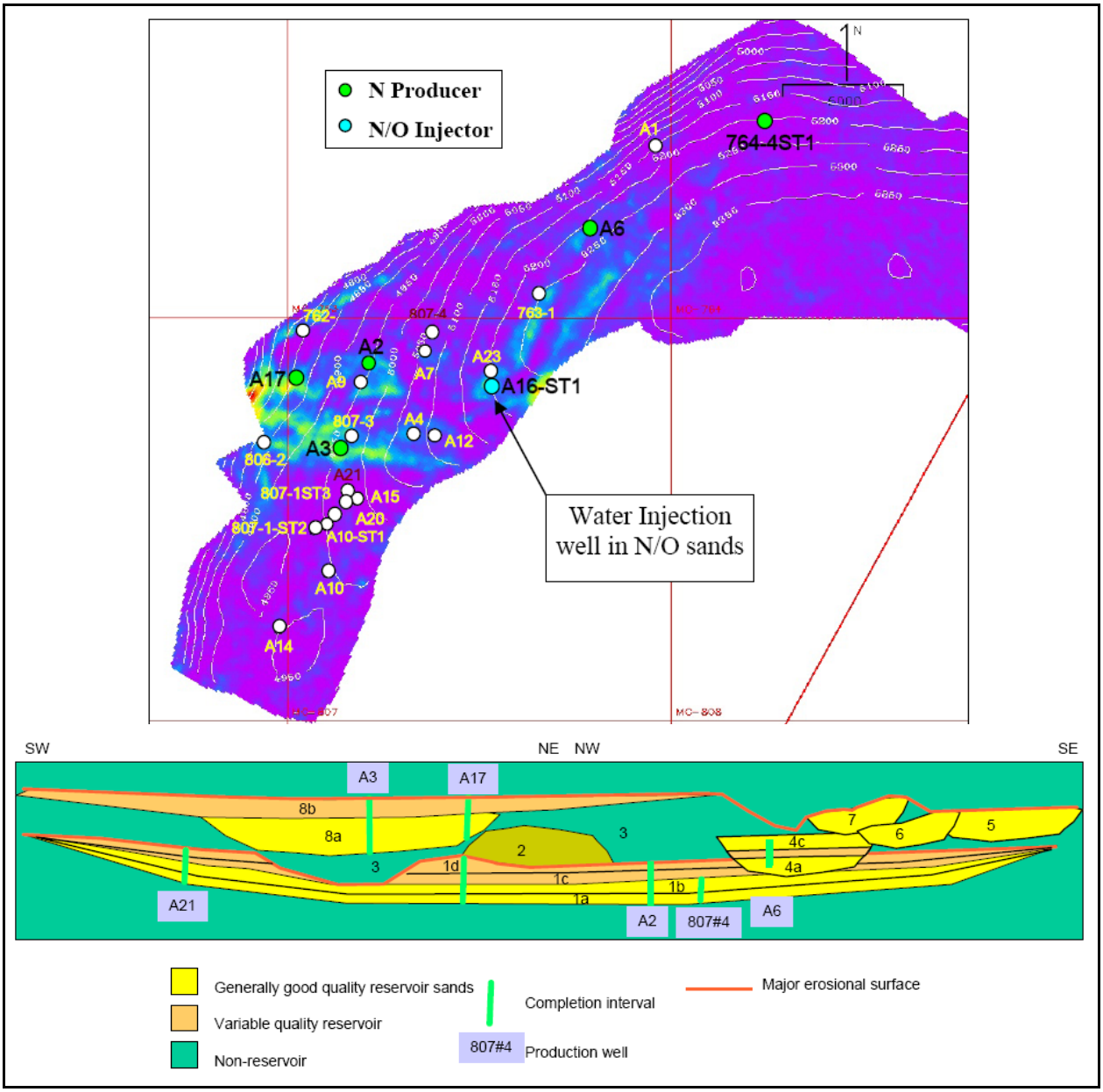


Figure 58: N/O sand structure map (Weiland, 2008) and cross-section (Reynolds, 2000)

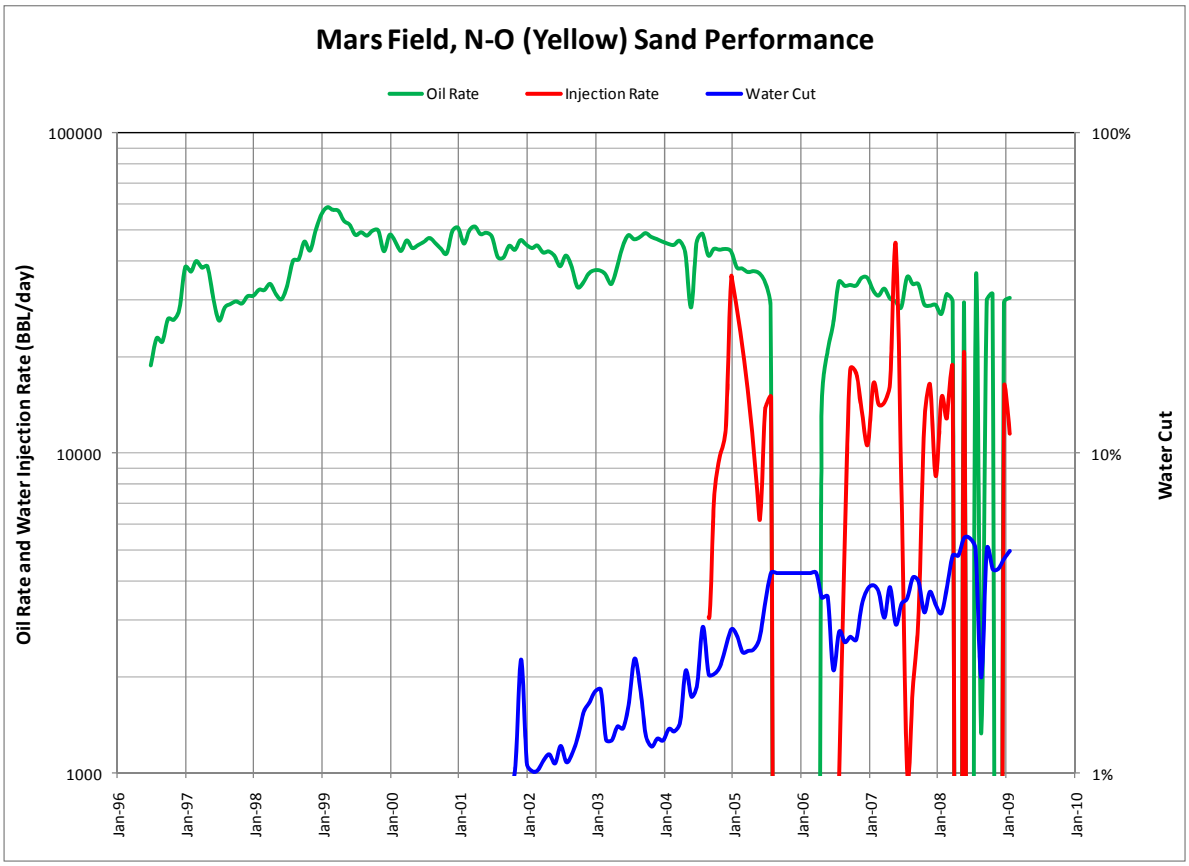


Figure 59: Mars N/O sand production and injection history

Table 23: Waterflood performance and incremental oil, Mars field reservoirs

Volumes and Recovery	N/O Sand (Yellow)	M1/M2 (Upper Green)	E (Pink)
Original oil in place (MMSTB)	534	339	227
Solution gas in place (BSCF)	566	237	154
Cumulative oil Oct. 2009 (MMSTB)	170	86	49
Cumulative gas Oct. 2009 (BSCF)	216	83	24
Cumulative water injection Oct. 2009 (MMSTB)	20	10	13
Water injected PV	0.02	0.02	0.08
Depletion oil EUR (MMSTB)	198	105	79
Depletion gas EUR (BSCF)	209	74	54

Depletion oil RF	37%	31%	35%
Depletion gas RF	37%	31%	35%
Waterflood oil EUR (MMSTB)	299	190	127

Valuable information on the operability of water injection at Mars field has been published by Weiland (2008) and Kenny (2009). A summary of the well completion issues is provided in Table 24. Cross-flow in multi-zone completions, due to pressure differentials, is an issue for sand control. It has resulted in sand fill and loss of one of two completion intervals and possibly a future strategy of limiting injectors to a single zone completion. Also, with the reuse of old appraisal and development wells, out of zone injection can be observed due to compromised cement isolation after years of formation compaction related casing strain.

Table 24: Mars well completion related challenges

Reservoir	Wells	Injection Start Date	Depletion at Start (psi)	Cumulative Injection (MMBW)	Target Injection Rate (BWIPD)	Injection THP (psi)	Cumulative Voidage Replacement	Notes
N/O	5 producers, 1 injector	Aug-04	4,500	17	33,000	6,200	0.02	1. Out of zone injection observed in nearby (400' away) producer. A 9000 BWIPD increase was seen in injector. 2. Rate is restricted to 20,000 BWIPD to mitigate out of zone communication. 3. Buildup of BHP has been observed around the injector.
M1/M2	2 producers, 1 injector	Apr-04	5,700	10	20,500	6,850	0.02	1. Suspect non uniform M1/M2 injection profile 2. Observed pitting below SCSSV in 13 Cr tubing. Oxygen is the expected mechanism. 3. Formation material infill observed at 14' below the gravel pack packer top. 4. Buildup of BHP has been observed around the injector.
E	1 producer, 1 injector	Jan-05	2,600	19	33,000	6,850	0.08	Sand fill in screen up to near the top perforation (ran in-well camera).

There are three well failures to date in Mars history due to compaction related casing collapse. Shell estimates that casing strains between 7 – 8% is the most likely point of potential casing failure. Some wells in waterflood areas have already seen strain up to 6%. The waterflood and pressure stabilization is needed to prevent future well failures.

Shell reported plans to drill five additional injectors over the next 2 years for E2 (Sub Pink), M2 (Upper Green), N (Upper Yellow), O (Lower Yellow) and K2 (Carmine). Future injectors will target a single zone with no commingling of injection to prevent cross-flow and interference issues caused differences in properties between layers/zones.

9.2.1.3 *Horn Mountain Field*

Horn Mountain field is located in Mississippi Canyon Block 127 in the Gulf of Mexico roughly 100 miles southeast of New Orleans in approximately 5,420 feet of water. BP is the operator of the field and holds 67%, interest; Occidental Petroleum Corporation holds the remaining 33% interest. First oil was November 2002 and water injection commenced in September 2003.

The current field development includes eight production wells and two injection wells with dry trees on a truss spar facility. Production is from the 2 Miocene reservoirs, the M and J sands. Reservoir facies are characterized as sand-filled channels and associated overbank deposits in combination structural and stratigraphic traps. Cumulative field production was 102 MMBOE gross at end 2008. The largest accumulation is the M sand (82% of reserves).

The performance of the waterflood in the M sand is reviewed in detail in AAPG Bulletin, v. 91, no. 6 (June 2007), pp. 847–876 by Milkov, et al. Also, the performance and incremental recovery projections were presented by Dixon at the 13th Annual Deepwater Symposium, August 2009. A summary of the performance and expected incremental oil recovery is discussed below.

The M sand forms a gently south and southwest dipping structure with updip faulting and thinning (Figure 60). Several smaller faults and depositional features (channel boundaries and overbank facies) separate the M sand into northwest, central, and eastern fault blocks. The oil-water contact (OWC) has not been penetrated and is estimated at 14,300 ft TVDSS in the main part of the reservoir and 14,200 ft TVDSS in the eastern area.

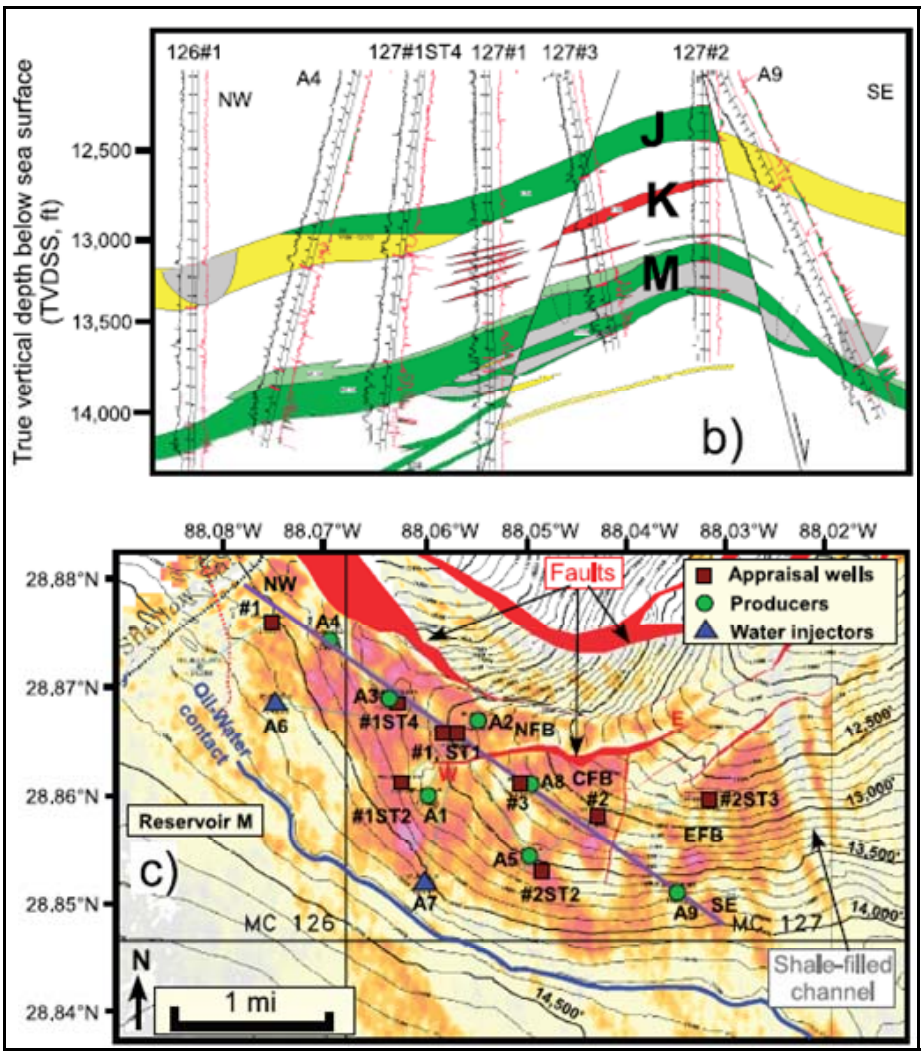


Figure 60: Horn Mountain structure and cross-section, Milkov (AAPG, 2007)

The average reservoir properties of the M sand are shown in Table 25. The reservoir is only moderately over-pressured with an initial gradient of 0.52 psi/ft to mean sea level. Water injection was designed into the primary development plan due to the expectation that aquifer influx and rock compaction would be limited. Water has been injected in wells A6 and A7 (Figure 60) since September 2003.

Table 25: Horn Mountain M sand properties

Reservoir Property		M Sand
Area (acre)		3,497
Completion(s)		7 producers, 2 injectors
K (md)	**Distal levee**	183
	Proximal levee	309
	Channel-fill	1360
N/G	**Distal levee**	0.35
	Proximal levee	0.69
	Channel-fill	0.84
Thickness (ft)		64 - 398
Porosity Range		0.14 – 0.34
Water Saturation, Swi		0.24
Initial Oil FVF (rb/sfb)		1.32
Initial Pressure @14,200' (psia)		7,035

Water break-through occurred after 2 years and significant water has been produced over the life of the reservoir (Figure 61). Dixon (2009) reported that the water injection system uptime has been much lower than expected due to pump failures, deaerator problems, and flowline leaks. The history matching of reservoir performance has highlighted that the aquifer influx has been much stronger than anticipated and rock compaction has also been higher than expected. The continuity between injectors and producers has been less than expected (Dixon, 2009), and the aquifer is providing 50 – 60% of total reservoir energy even with injection.

A summary of the M sand OOIP, estimated primary oil recovery, and incremental oil recovery from water injection are shown in Table 26. The cumulative injected water is currently only 0.04 of total pore volume. The primary recovery factor and waterflood IOR are based on MMS reported OOIP (provided by the operator) and the reported water injection incremental of 15 MMSTB (Dixon, 2009). The primary recovery factor is estimated at 35% and the waterflood IOR is 5% of OOIP. BP plans to continue water injection to supplement the aquifer and to improve sweep efficiency.

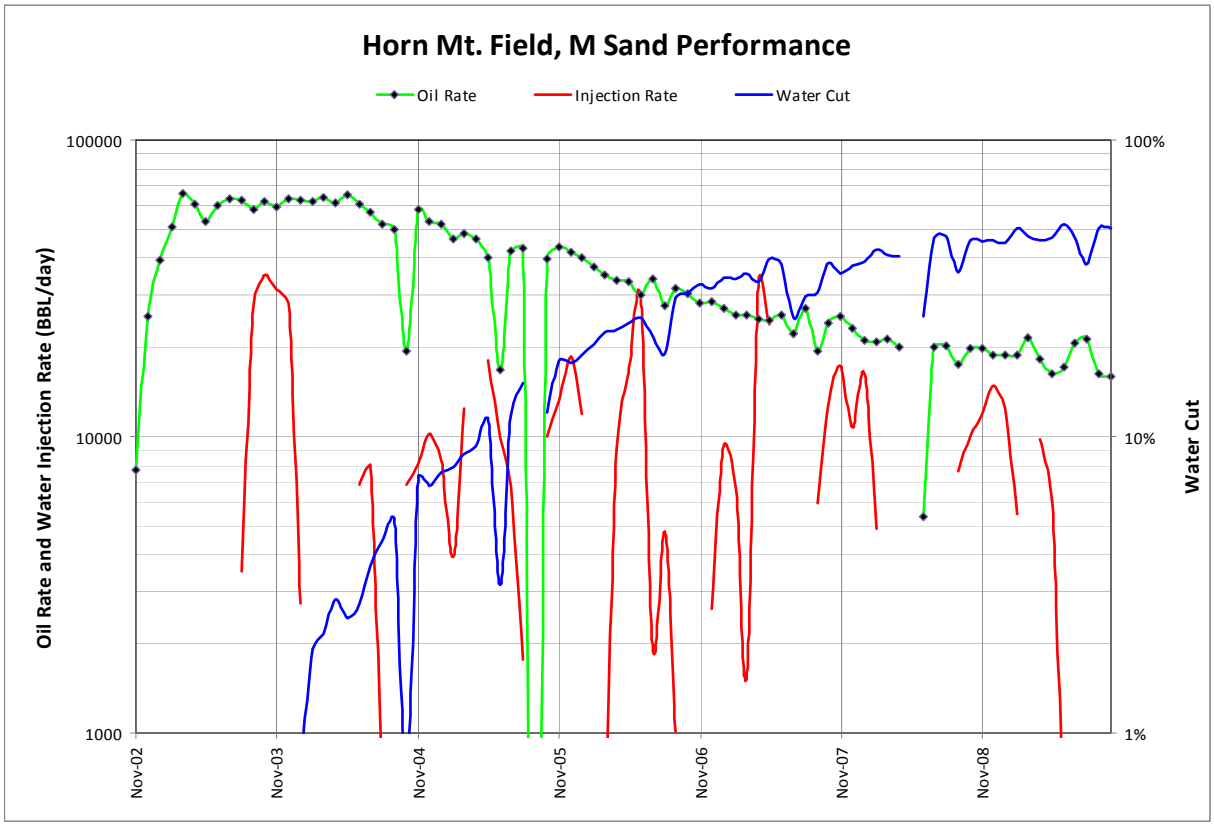


Figure 61: Horn Mountain, M sand production and injection history

Table 26: Horn Mountain M sand oil RF and waterflood IOR

Volumes and Recovery	M Sand
Original oil in place (MMSTB)	280
Solution gas in place (BSCF)	223
Cumulative oil Oct. 2009 (MMSTB)	81
Cumulative gas Oct. 2009 (BSCF)	68
Cumulative water injection Oct. 2009 (MMSTB)	18
Water injected PV	0.04
Primary oil EUR (MMSTB)	98
Primary gas EUR (BSCF)	78
Depletion oil RF	35%
Depletion gas RF	35%
Waterflood oil EUR (MMSTB)	113
Waterflood oil RF	40%
Waterflood IOR	5%

9.2.1.4 *Summary of Deepwater GOM Waterflooding Experience*

The Mars, Petronius, Horn Mountain, and Holstein fields have been reviewed in detail for water injection performance. The results are summarized to forecast a range of waterflood IOR for other deepwater GOM reservoirs.

The current oil recovery versus pore volumes of water injected for a number of the waterflood reservoirs is shown in Figure 62. Only the Petronius field is mature enough and has injected considerable pore volumes of water. The Mars field reservoirs show the oil recovery at the start of injection was already greater than 20% and was forecasted to reach the mid 30's RF from strong rock compaction drive energy. The Holstein field is in the early years of development, and the forecast waterflood recovery is less certain.

Overall, waterflooding has been highly effective and has provided good incremental oil recovery for the deepwater Gulf of Mexico reservoirs. The estimate of primary recovery, secondary recovery, and incremental from waterflooding is summarized in Table 27. Incremental recovery factor ranges from 5% to 37% of OOIP. The low IOR from Horn Mountain is only low because the aquifer strength turned out to be higher than expected. Having water injection facilities at Horn Mountain however did protect the potential downside of recovery given the uncertainties at the time of field development. The high IOR of 37% at Petronius is a unique case given the presence of an initial gas cap, expected low rock compressibility, and moderately low initial pressure.

If the economic limit of water cut is set to 80%, the waterflood IORs evaluated by the sector model of Neogene reservoir range from 12-18% based on different voidage displacement of injection (Appendix A). The waterflood IORs ranges from 14.9-21.8% if the economic is re-set to 90%.

Given the performance of existing waterfloods, an incremental oil RF range from 4% to 25% has been used for future scoping of IOR in other fields/reservoirs.

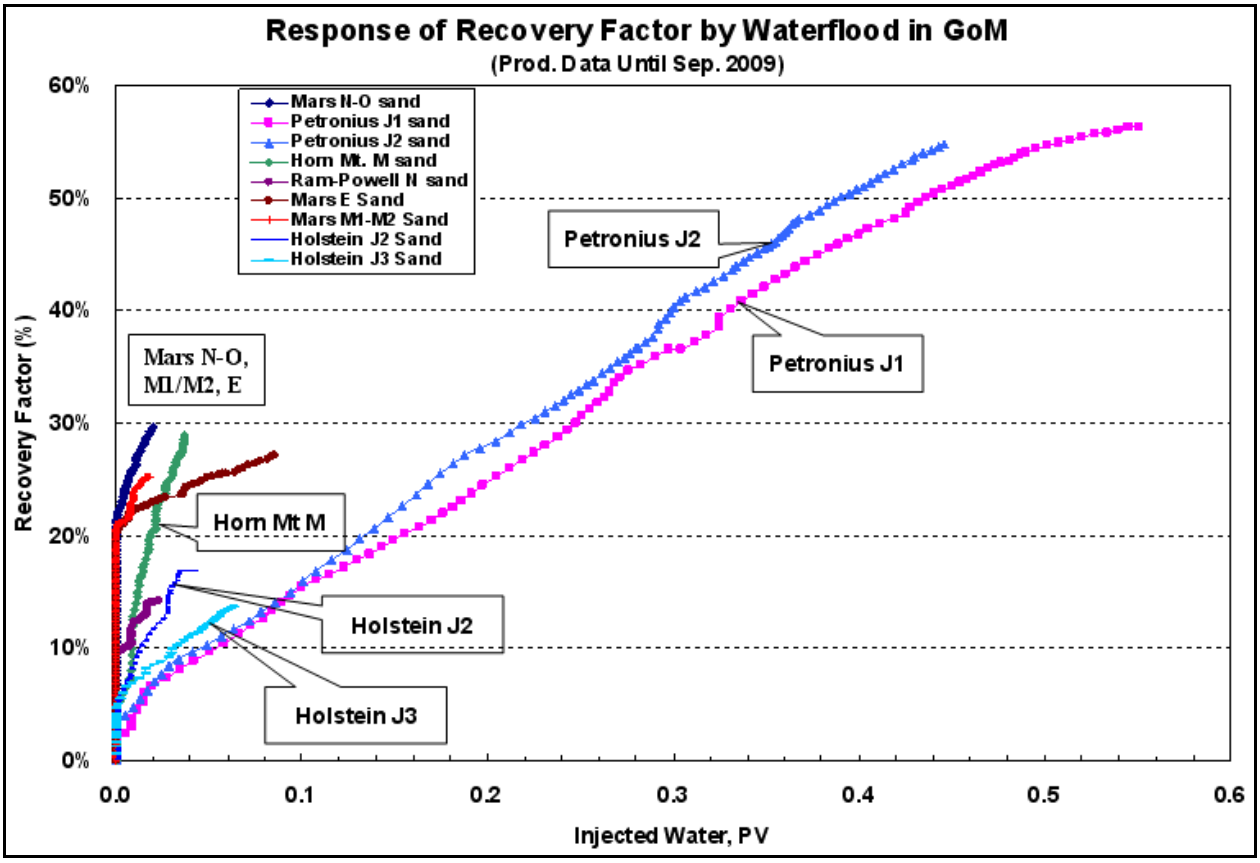


Figure 62: Oil recovery factor vs. pore volumes of injected water, deepwater GOM

Table 27: Summary of DW GOM incremental oil RF from waterflooding

Field	Reservoir	OOIP (MMSTB)	Cum Oil Sep-09 (MMSTB)	Current Oil RF Sep-09	Forecast Primary Oil RF	Forecast Oil EUR (MMSTB)	Forecast Oil RF	Waterflood IOR
Mars	N	573	170	30%	37%[1]	321	56%[3]	19%
	M1/M2	341	86	25%	31%[1]	191	56%[3]	25%
	E	225	50	22%	35%[1]	126	56%[3]	21%
Petronius	J1	109	59	54%	20%[2]	62	57%	37%
	J2	80	42	52%	28%[2]	43	54%	27%
Horn Mt.	M	280	81	29%	35%	112	40%	5%
Holstein	J2	138	23	17%	20%[2]	73	53%	33%
	J3	84	11	14%	20%[2]	45	53%	33%

Notes:
1. Based on decline analysis prior to start of injection.
2. Material balance estimate
3. Forecast using cross-section sector simulation model as function of voidage replacement ratio.

9.2.2 Seafloor Water Injection

The concept of seafloor water injection has been around for many years but has had limited use. It includes the use of subsea injectors with subsea trees that include equipment for the intake, filtration, and pumping of seawater directly into the well. Additionally, the equipment includes electro-hydraulic well control from the host platform along with chemical injection lines and controls.

Seafloor water injection is an alternative to conventional surface equipment and pipelines for "brownfield" developments with space and weight limitations on the host facilities or for long step-out and ultra-deep developments. There is a larger cost differential between conventional water injection facilities and seafloor water injection systems with deeper water depths and longer tie-back distance (Roberson, 2007 and Eden, 1998). The main drawbacks for seafloor water injection are:

- Higher well/equipment intervention costs
- Uncertainty and less control for the potential of reservoir souring
- Less operational control for the potential of well solids-related plugging

The application in deepwater GOM is for subsea tie-backs with limited capacity to add injection facilities on the local host and as a low-cost alternative for smaller OOIP reservoirs. Additionally, developments in ultra-deepwater may be more dependent on longer tie-back tie-back distances. The K2 field, for which data on IOR evaluation was provided to this RPSEA project, is a candidate for seafloor water injection.

For the evaluation of future IOR potential from seafloor water injection, an increment oil RF range was estimated by scaling back the IOR ranges for conventional waterflooding assuming a loss of operability. The conventional IOR range 4% - 25% (P90 – P10) was downgraded to 4% to 18% to account for the loss of operational control and the higher potential for scaling, corrosion, and souring related issues. Several field applications of seafloor water injection are discussed below.

9.2.2.1 *Key Analogs for Offshore Seafloor Water Injection*

The Tyrihans field in the Norwegian North Sea has recently been developed and includes one well for injection of seafloor water (Grynning, 2009). The field is tied back 22 miles to the remote host at Asgard field. The seafloor water injection system is designed to injection up to 126,000 Bbl/d water without filtration or chemical injection into the aquifer between north and south accumulations (Figure 63).

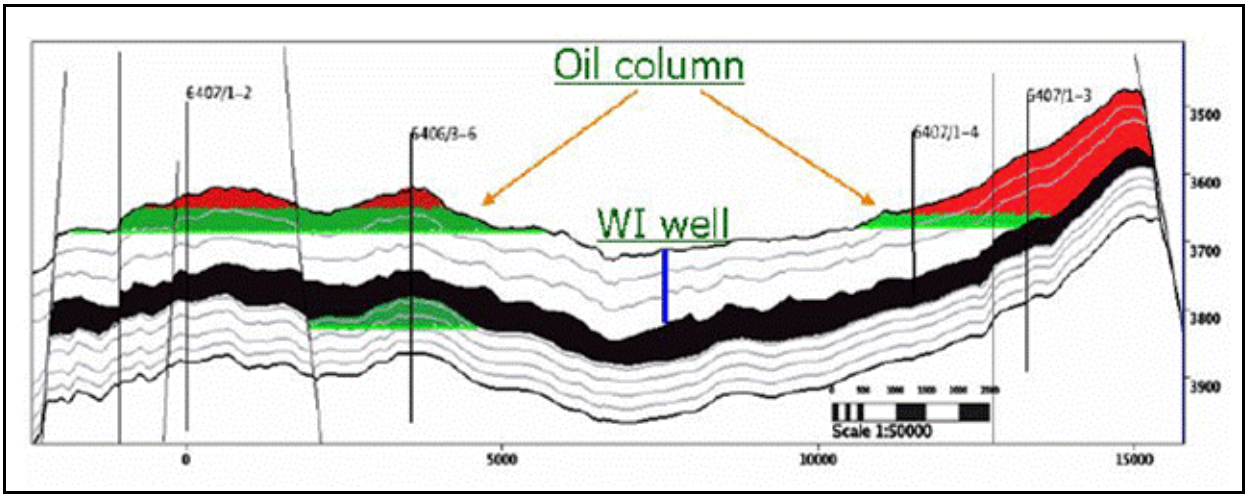


Figure 63: Tyrihans field implementation of seafloor water injection (Grynning)

Minimal injected seafloor water is expected to be produced and hence there is little concern for scaling at updip producers. There are no plans for continuous scale inhibitors or biocide injection. The system start up was expected in January 2010, but no published performance data are available for reporting here. The forecast of incremental production from water injection is 10% of OOIP.

The Barton field in offshore Malaysia was evaluated by Shell (Flatval, 2004) for application due to space and weight limitations on the existing platform. In the case of Barton, seafloor water injection is an alternative to building a second, bridge-linked platform. The evaluation by Flatval, et al (SPE 88568, 2004) provides a good overview of the risks and evaluation of those risks for scaling, corrosion, souring, and injectivity issues associated with seafloor water injection. It would appear at this writing that the Barton field project was never sanctioned, although this was not confirmed. The forecast IOR for seafloor water injection in the Barton field was 6% of OOIP.

The Columba Terraces field in the UK North Sea had a planned seafloor water injection project which was reviewed in detail by Rogerson and Laing (SPE 109090, 2007). The application was required due to space and weight limitation on the host Ninian south platform. A platform injector was drilled in 2002 and commenced injection in 2003. It proved the incremental potential from waterflooding and led to the planning and design of additional injection. The plan called for 2 subsea wells with seafloor water injection equipment.

The Columba Terraces project raw seawater is filtered and boosted at the seabed using electrically driven centrifugal pumps designed by Framo Engineering. The high pressure water is delivered via jumpers from the Framo Dual Pump Station to the wellheads. A near-shore subsea wet test of the equipment was run in 2006 and field installation was planned for 2008. The performance and reliability of equipment has not been reported for further review.

In the Norne field on the Norwegian continental shelf, deaeration of the injection water has been eliminated since the presence of oxygen in the injected seawater is expected to stimulate reservoir productivity is injecting. The seawater is combined with produced water for the full injection stream. The Norne field is unique in that the application of partial seafloor water injection is included for a development with FPSO and wet trees. Hence, injection pumps are located on the FPSO and delivery of water is through pipelines. Wells are equipped with more expensive corrosion resistant tubular.

9.2.3 Aquifer Dump Flooding

The concept of aquifer dump flooding is to use an over or underlying aquifer reservoir in the field to supply injection water in the injection well completion. The well is completed as a dual aquifer water supply well and zone-of-interest injector. It only applies where an aquifer of sufficient volume is present and compatible with the oil reservoir fluids. The historical use of aquifer dump flooding has been done in wells with simple completions. It is expected that the pressures and depths of the deepwater Gulf of Mexico will require much more sophisticated well completion technology.

Some of the earliest use of aquifer dump flooding was in the Ghawar and Abqaiq fields in Saudi Arabia prior to the use of seawater for injection. These fields were produced by primary means for a number of years prior to injection. Aquifer dump flooding was used as an early, low-cost injection alternative. The Wafra Formation aquifer was completed above the Arab-D Formation and due to the pressure differential from depletion, water cross-flowed into the Arab-D. Production logging was used to monitor and estimate injection volumes. This operation was halted after the Wafra Formation water table began to significantly rise, and Saudi Aramco switched to a seawater injection system.

The application of aquifer dump flooding has potential in the deepwater Gulf of Mexico because there are aquifers typically present in most fields. The over-pressured reservoirs also make this a good alternative since depletion of the hydrocarbon zones will provide the pressure differential for good cross-flow rates. The largest challenge is probably in the completion and equipment required to operated the well and gauge or control injected volumes. For scoping of potential, the conventional waterflood IOR range of 4 – 25% was scaled down to 4 – 18% for dump flooding due to loss of operational control.

The October field in offshore Egypt has several wells where aquifer dump flooding is used (Ibrahim, 2008). In the October field there is a mixture of surface injection and dump flooding. The Zeit aquifer is used as the source for all injection water. The use of the aquifer for all source water provides added benefits of reduced risk for scaling, corrosion, and souring. No downhole flow control values are used to control the injection rate as shown in the completion diagram of Figure 64.

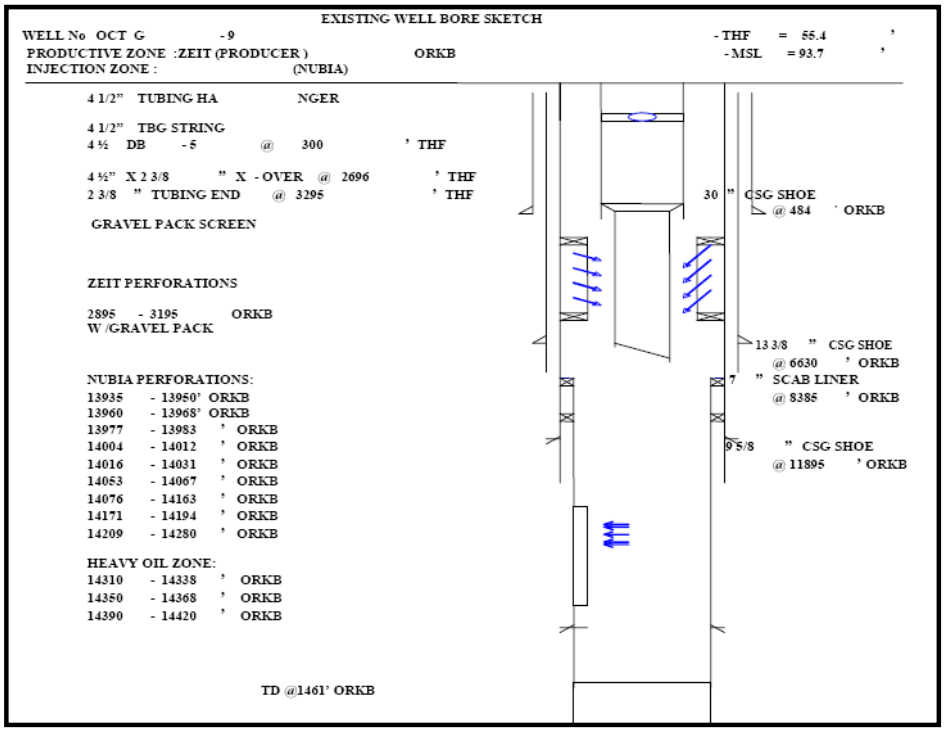


Figure 64: Aquifer dump flood completion, October field, Egypt (Ibrahim, 2008)

9.2.4 Low Salinity Water Injection

Low salinity water injection is a water-based EOR method intended for the tertiary stage of field development. As the name implies, the process involves injection of low-salinity brine having a composition of less than 6,000 ppm of total dissolved solids. Preparing the correct brine concentration compatible with reservoir rock and fluids is accomplished via topside water treatment, desalination, and injection facilities. A reverse osmosis desalination plant can be a major cost center for the operation; however, lower cost membrane technology is becoming available for reducing the footprint and cost for desalination.

The low-salinity process acts on capillary forces holding oil in reservoir pores, reducing interfacial tension between formation minerals and oil complexes. Incremental oil is obtained by a water chemistry adjustment that leads to improved reservoir rock wettability.

Low salinity brine drives pore-level multi-component ion exchange (MIE) whereby capillary-bound oil is released from charged clay minerals. This ion exchange mechanism is believed to be a function of rock type, original wettability state, formation water composition and pH, polar components in crude oil, injection water chemistry, type and amount of clay present, and oil viscosity. The foremost challenge in designing a low-salinity field application is properly defining the fundamental chemical-mechanistic relationships in order to formulate a reliable pore-scale prediction model. Without a clear understanding of the interplay between rock mineralogy, water chemistry and wettability condition, this injection technology remains obscure. An average increase in recovery of about 14% was observed in core studies (Austad et al., 2010).

The benefits of low-salinity scale with clay, fraction since the effect depends on clay minerals acting as a cation exchanger. Clays with smaller cation exchange capacities are expected to yield lower recoveries. At the same time, injection failure can be bought on by an abundance of swelling clays. The IOR process has little impact on reservoir rock that is initially too water-wet for mobilizing any remaining bound oil.

Several recent technical papers (Boussour, et al, 2009 and Ashraf, et al, 2010) provide a thorough review of published work on the evaluation of low-salinity water injection and the proposed mechanisms for incremental recovery. Most of the experience is from core flooding. The only significant field pilots have been done by BP in the Endicott and Prudhoe Bay fields, North Slope of Alaska. Seccombe et al. (2008) and McGuire et al. (2005) reported on the results of single well chemical tracer tests (SWCTT) performed on a number of wells. They showed that core flooding results could be duplicated in the field with residual oil saturations significantly reduced after low-salinity water injection. BP observed that low-salinity water injection could increase oil recovery by 6 – 12% of OOIP after waterflood recovery.

The sector model of Neogene reservoir simulation is run where low-salinity water is injected in secondary recovery mode after one and half year depletion. The LowSal injection was run with different voidage ratios. The results of incremental oil recovery for low-salinity water injection have a range of 2.5-5.2% when 80% water cut is set as economic limit (Table 52).

Still an emerging EOR technology, low-salinity is one of the most promising injection processes because of potential upside and simple field practice. For the purposes of evaluation potential resource values in the deepwater Gulf of Mexico, an incremental oil recovery range of 3% to 7% of OOIP is estimated assuming low-salinity injection is applied as a tertiary recovery method.

9.2.5 Microbial Enhanced Oil Recovery (MEOR)

Microbial enhanced oil recovery (MEOR) is the dosing of injection water with bacteria and nutrients for the stimulation of in-situ microbes as an improved oil recovery process. The process makes use of nutrients and oxygen in the right combination of acidity, temperature and salinity so that the bacteria look to oil for their carbon source. The result is bacteria growth in-situ and the production of enzymes that have a surfactant effect of reducing interfacial tension and reducing residual oil saturation.

Bacterial stimulation and growth in the reservoir also results in a temporary plugging effect which acts to divert water into previously unswept areas. This in turn aids to increase macroscopic sweep efficiency.

Offshore trials with MEOR were tried in the Beatrice, Ninian, and Murchison fields in the UK North Sea in the 1990s. The reported results were ambiguous and not widely perceived as positive which led to little interest in MEOR over the past 10 – 15 years.

In the Norwegian sector of the North Sea, Statoil has advanced considerable research on MEOR. Statoil has patented a process of MEOR and has implemented a large scale MEOR flood with the water injection in the Norne field. Also in Norne field Statoil has elected to stop injection water deaeration so that oxygen is provided to the reservoir in support of bacteria growth and stimulating the MEOR process. No information was available on the response and effectiveness of MEOR in Norne.

The application of MEOR is fairly easy to implement in deepwater Gulf of Mexico where there is an existing waterflood project. The footprint of surface equipment to provide microbes and nutrients for injection with the water is quite small since large volumes are not required. An issue with potential application is reservoir temperature since current microbe technology appears to be limited to around 180 F. However, MEOR is included on the list of potential IOR processes since there is ongoing research in the development of thermophilic bacteria.

The MEOR process is not well understood and has a mixed track record of performance. Therefore, it is considered more uncertain and given a lower rating for technical readiness. The forecast range of IOR with MEOR is from 1% to 5%, kept low due to mixed results in other published trials and field applications.

9.2.6 Alkaline Surfactant Polymer (ASP) Flooding

ASP is an alternative to surfactant flooding developed in the 1980's where lower cost alkaline chemicals (Na2CO3 or NaOH) are mixed in solution with a lower dosage of the more expensive surfactants and polymer for mobility control to reduce interfacial tension (IFT). Currently ASP is one of the most commercially applied onshore chemical EOR processes. However, its application thus far has been limited to a smaller set of reservoirs typically with low to medium gravity (API 18 – 25) and moderate viscosity (2 – 100 cP).

A key aspect is the ability of alkaline agents to change rock chemistry which significantly decreases the chemical adsorption. Many light oils do not contain sufficient amounts of the components that react with alkali to reduce the oil-water interfacial tension sufficiently to overcome capillary forces trapping the oil. Blending surfactant with alkali can overcome this barrier. An example of alkali-surfactant concentrations and their affect on IFT is shown in some work by Surtek, a leading company in the supply of ASP technology (Figure 65).

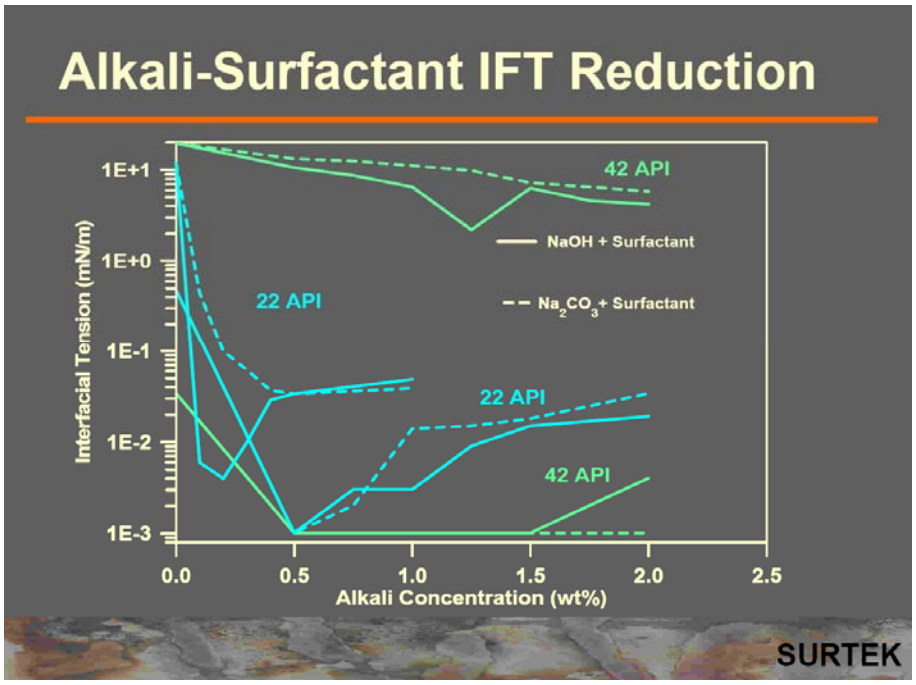


Figure 65: ASP lab work to select alkali concentration

In planning for ASP flooding, a formulation of alkali and surfactant must be designed specifically for each reservoir rock and fluid. Chemical performance is adversely affected by clay and carbonate minerals. Typical field examples of chemical content are 1% wt of sodium hydroxide (NaOH), with 0.1 – 0.2 wt% surfactant, and 700 – 1000 ppm polymer mixed as a slug and injected in a volume of 0.25 to 0.40 reservoir pore volumes. The ASP slug is followed by polymer for mobility control.

For an offshore flood, the handling and injection of a 0.25-0.40 PV slug of chemical is a huge and expensive undertaking. ASP and most other chemical flooding processes have not been tried offshore due to the large volumes required for injection. Even in the mature North Sea, chemical flooding has not been attempted, at least in large EOR processes. The OG21 IOR study group did recommend future research work in chemical EOR for the next step in further increasing oil recovery on the Norwegian continental shelf.

A technical IOR range for ASP from 5% to 20% was estimate for deepwater GOM based on the onshore successes. This does not account for the economic viability of chemical flooding offshore.

9.2.7 Other Chemical Flooding

Other chemical flooding alternatives were included on the list of potential IOR processes for Neogene age reservoirs. However, there is very little activity in micellar polymer flooding or other chemical surfactant use either onshore or offshore.

9.2.8 Hydrocarbon Gas Injection

In conventional hydrocarbon gas injection, a mixture of liquid hydrocarbons, commonly a stream consisting of propane (C3) to pentanes (C5) is employed for displacing residual oil with greater sweep efficiency. Several displacement mechanisms come together for improved recovery. Gas flooding creates an artificial drive by injectant expansion, reservoir fluid swelling, and oil viscosity reduction from injectant solubility.

When injection pressures exceed the minimum miscibility pressure (MPP) for the hydrocarbon gas, the injectant dissolves in reservoir oil either at first contact or multiple contacts, lowering the surface tension through mass transfer in the transition zone. At high pressures in a vaporizing drive, lighter components in the oil (C2-C6) are vaporized to generate miscibility. The injectant's high velocity, a basis for injectivity improvement over waterflooding, energizes the reservoir fluids. This behavior may lead to by-passing and break-through.

Supply logistics for the gas injectant are among the main operating hurdles. Produced gas associated with low-GOR oil may not yield required volumes nor is a ready supply of make-up gas available in the event of a shortfall. Regardless of sourcing problems, this IOR process utilizes large quantities of valuable hydrocarbons. A topside straddle plant for stripping C3-C5 from the produced gas stream is capital-intensive. Furthermore, post-separation compressors and pumps are needed to deliver the mixed injectant to the reservoir. An advantage, however, is that no produced gas is stranded since the C1-C2 residual serves as fuel for platform utilities.

The most extensive and well documented field experience for offshore hydrocarbon gas injection is in the North Sea. In most North Sea applications water injection is the primary recovery mechanism, and gas injection has been used to enhance oil recovery. The injected gas is often in downdip locations in water-alternating-gas (WAG) schemes. Large slugs are injected in downdip wells followed by the WAG. The observed benefits are:

- Drainage of attic oil
- Reduction of residual oil saturation
- Changing sweep patterns and gas lifting of high water cut wells

A number of technical papers have been reviewed to record and summarize the incremental oil recovery benefits of hydrocarbon gas injection in the North Sea. The injection projects are grouped into categories of miscible, miscible WAG and immiscible WAG recovery methods. The predicted IOR ranges from 1% to 12% of OOIP.

Table 28: Hydrocarbon gas injection projects and IOR for North Sea fields

IOR process	Field name	Reservoir	Target OOIP (mmstb)	Predicted Incremental RF
Miscible gas injection	Alwyn North	Brent	597	3.30%
	Brent	Statfjord	3793	1.40%
	Ekofisk	Ekofisk	6720	2-3%
Miscible WAG	Snorre	Statfjord	3341	10-12%
	South Brae	Upper Brae	829	3%
	Magnus	MSM	1539	2-6%
Immiscible WAG	Thistle	Brent-Tarbert	823	
	Gullfaks	L-Brent	3655	8-10%
	Brage	Fensfjord	760	5%
	Ekofisk	Ekofisk	6720	3%
	Statfjord	Brent	6280	7%
	Oseberg Ost	Brent	609	
Immiscible IWAG	Kuparuk River			1-3%

The incremental oil recovery potential for deepwater GOM is estimated to range from 3% - 12% based mostly on North Sea experience and the assumption of its use as enhancing secondary water injection. The main issues with implementing gas injection in deepwater GOM are:

- Lack of sufficient hydrocarbon gas supply and deferred sales revenue
- Limited number of current water injection projects
- Large well spacing and poor reservoir description
- Long required response time
- Poor macroscopic sweep because of highly permeability zones or faulting
- Near-well two-phase relative permeability effects and potential impact on injectivity
- Tubing malfunction owing to heating and expansion from injected gas
- Corrosion and hydrate formation issues

9.2.9 Gas Dump Flooding

The process of gas dump flooding is similar to aquifer dump flooding where a source reservoir in the field is used to supply the injected source downhole. It requires the presence of a gas reservoir located structurally above or below the target oil reservoir. After some depletion of the oil zone, the injecting well can be completed dually in the gas reservoir and oil zone to allow for cross-flow.

The concept of gas dump flooding has not been used in any field. Gas reservoirs have been used to “bleed” gas into the wellbore for artificial lift purposes; however, the proposed process here is for adding reservoir drive energy and improving sweep efficiency in the reservoir. The conventional hydrocarbon gas injection IOR has been downgraded to a range of 3% to 8% of OOIP for the potential of gas dump flooding.

9.2.10 Nitrogen Injection

Nitrogen projects include miscible flood, immiscible drive, gravity drainage enhancement and pressure maintenance, applied independently or in some combination thereof to achieve improved recovery. The general principles underlying the displacement mechanism are largely the same as for conventional hydrocarbon gas injection. Incremental oil is obtained from targeting capillary-bound oil and by increasing sweep efficiency. Pressure support is achieved either from the injectant phase alone in the immiscible operation or by expansion of gases dissolved in the transition zone.

At least 5,000 feet of depth is necessary for withstanding high injection pressures supporting miscibility without the risk of fracturing. Correct estimation of the MPP and the asphaltene onset pressure are also critical design parameters. Reservoir oils with an asphaltene content of more than 10 weight % are exposed to instability. Cryogenic processes with proven technology can produce almost pure nitrogen that is very dry and non-corrosive, and environmentally safe. The downside of nitrogen generation is the additional weight the cryogenic unit adds to the platform and the eventual contamination of the production stream by the injectant. The possible mechanisms for improved oil recovery from nitrogen injection are: immiscible displacement, miscible displacement, gravity drainage enhancement, pressure maintenance, and as a driving fluid for a miscible solvent slug.

Good alternate to hydrocarbon gas flooding where insufficient hydrocarbons gas is available for injection.

One key issue identified in screening for application at K2 field in DW GOM was the substantial increase of asphaltene onset pressure with increasing GOR from both hydrocarbon and nitrogen miscibility. The implication was possible asphaltene deposition in the reservoir.

The largest offshore nitrogen injection project is in the Cantarell field, operated by Pemex in the Gulf of Mexico. The field is 50 miles offshore and nitrogen is generated onshore and piped to the facility

9.2.11 CO2 Injection

Carbon dioxide flooding and its variations are usually undertaken as gas-based EOR processes in reservoirs that have been depleted by primary means and possibly water injection (Figure 66). Modified applications of the base IOR scheme include immiscible CO2 injection, miscible displacement by CO2, water-alternating CO2 gas (WAG) injection (Figure 67), and cyclic carbon dioxide stimulation also known as CO2 “huff-and-puff”. All techniques except the cyclic method are normally pattern floods whereas the huff-and-puff procedure is a single well operation.

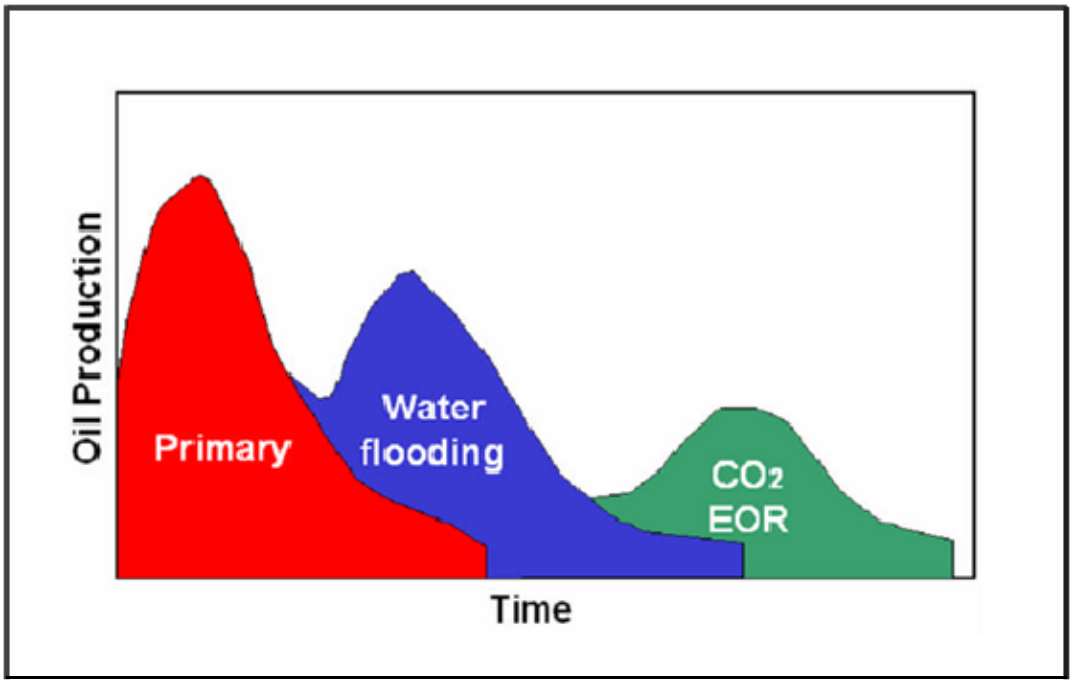


Figure 66: Expected Sequence of Oil Recovery Methods. From (Carr et al., 2005)

When carbon dioxide is introduced into the reservoir, the displacement mechanism relies on phase behavior of CO2 and crude oil mixtures that are strongly dependent on reservoir temperature, pressure, and oil composition. At the pore-scale level, the effect of CO2 solubility is to swell the oil and reduce its viscosity. CO2 gas also energizes oil from its high emissivity. Immiscible floods can be carried out at low pressures while miscible projects have injection pressures exceeding the minimum miscibility pressure (MMP) of CO2. A miscible front is generated from multiple contacts with oil having a high percentage of C5 through C12 intermediates. In the transition zone, a gradual mass transfer of lighter hydrocarbons occurs from the oil to the CO2 thereby creating a bank of enriched gas that is mobilized towards production wells. Operating above the MMP requires a reservoir depth of 4,000 feet or more.

Good candidates for miscible CO2 injection are reservoirs with light oils (> 26 API) and low viscosity (< 10 cp). Oil saturations should be at least 20%. Immiscible IOR is suitable for heavy and medium crudes of 12-25 API. Variable permeability and compartmentalization impact flood profile control.

CO2 supply lines clustered along the Gulf Coast serve Permian Basin CO2 EOR projects and connect large geostorage sites in the south-eastern parts of the U.S. for selling to other destinations. Proposed offshore CO2 projects could be tied into these coastal marketing areas through utility pipelines of 150 miles or more. Alternatively, delivery of liquid CO2 to a remote platform can be made by ship in batch transactions. Either option runs the risk of disruption in the CO2 supply. Utilization factors depend on the CO2 strategy selected and are generally less for the WAG process since a tandem waterflood reduces the CO2 volume requirement. A secondary benefit of CO2 usage is the possible future incentive to earn carbon credits or revenue for qualifying greenhouse gas reduction in an EOR project.

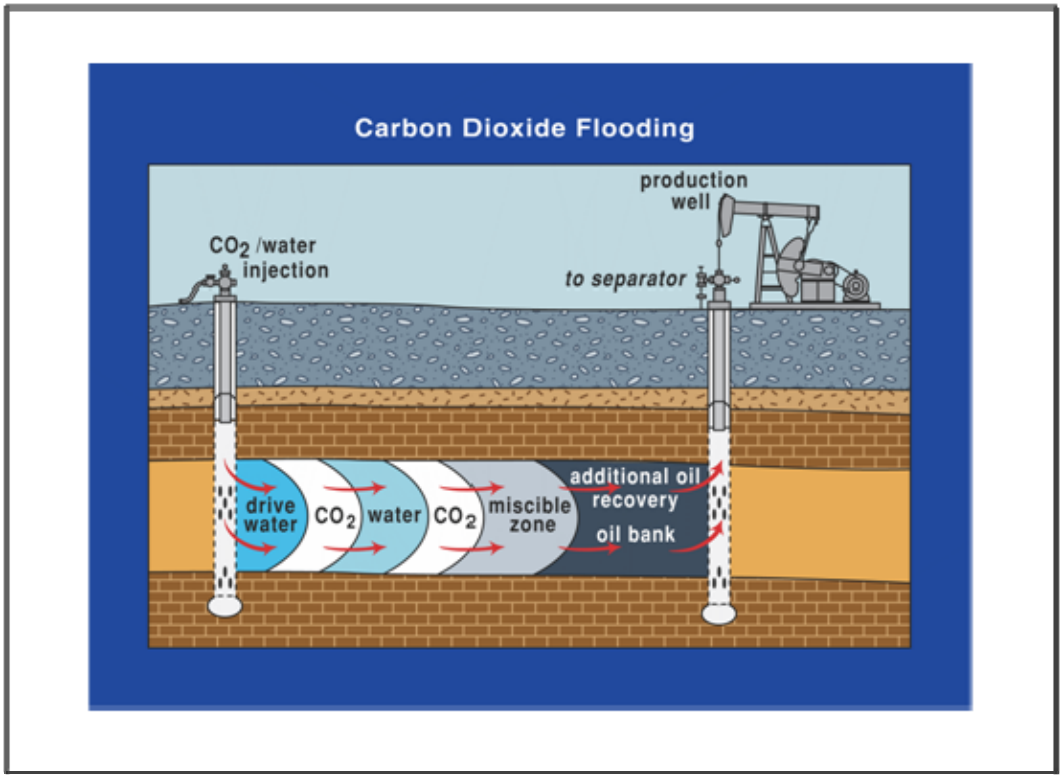


Figure 67: Onshore CO2 flood demonstration (from Carr et al., 2005)

Regarding the success rate of CO2 EOR, carbon dioxide injection has been extensively tested in the laboratory and validated by field-scale operations. Numerous Permian Basin CO2 projects have contributed to the EOR experience base. Improvement in oil recovery by CO2 methods applied in U.S. fields range from 2 to 18% of OOIP. The Forest Reserve field in Trinidad is an onshore example (Kuuskraa et al., 2006). A gravity-stabilized miscible CO2 flooding concept was pilot-tested at Shell's Weeks island field in Louisiana. Feasibility studies for Norwegian continental shelf water-flooded reservoirs predicted incremental oil recovery of 3 to 7% (OG21, 2009). For CO2 potential in deepwater GOM, we have used an incremental oil range of 3% - 15%.

9.2.12 Diverting Agents

Microbial enhanced oil recovery, foam, and other chemicals are engineered solutions for a wide range of problems encountered in heterogeneous formations that have highly-stratified lithology, matrix variations, or fractures. Diverters act as plugging agents for selective zonal isolation in bedding with variable permeability. Smart systems have the added flexibility for temporarily plugging thief zones thus allowing the affected area to return to its original state after the desired application time has elapsed.

Diverting agents are remedies for low sweep efficiency. To achieve better conformance control during waterflooding operations, treatments such as MEOR can increase zonal injectivity, mobilizing about half of the oil attributed to poor sweep efficiency. Stable performance of a microbial culture in a harsh environment with elevated temperatures and pressures relies on careful management of nutrients, reservoir chemistry, and other biological controls. Sustaining growth for the prescribed period is critical to a successful MEOR treatment.

9.2.13 Pumping and Artificial Lift

Artificial lift in producing applications may benefit oil recovery by maintaining adequate production rates as reservoir pressure decline and reducing the abandonment pressure and increasing the economical water cut to increase the ultimate oil recovery. All Artificial lift methods work by adding energy to the flow stream of wellbore and flowline. The following artificial lift methods can be applied in Neogene field development practices:

- Subsea multi-phase pumping
- In-well gas lift
- In-well ESP
- Subsea processing

Subsea multi-phase pumping uses pump for pressure boosting at seafloor or riser to increase the pressure in flowline. The pump includes centrifugal, twin-screw, helico-axial, and electrical submersible pumps (ESP). Table 29 summarized the subsea pumping applications worldwide. According to the historical data, subsea runtimes are in excess of 2 years for all of these pumps, with the exception of twin-screw pumps which have had short run lives of approximately 1 year.

The placement of pumping equipment on the seafloor reduces of the need for topside equipment and deck space, and protects processing equipment from hurricanes. The reduction of topside equipment significantly reduces the CAPEX required to develop deepwater discoveries, including satellite fields that would otherwise be uneconomic. Seafloor processing enables subsea wells to be produced at higher rates and water cuts and to lower abandonment pressures, which results in greater ultimate recovery and the acceleration of reserves. Deepwater and satellite fields inherently have a greater distance to transport produced fluids to surface host platform, and require longer tie-backs (flowlines, pipelines and risers). Greater frictional pressure losses and hydrostatic pressures cause higher back-pressure on subsea wells, limiting production rates and ultimate recoveries. In deep water, the hydrostatic pressure of the fluid column is often five to ten times greater than the friction loss in horizontal pipes (Euphemio, 2009). The minimum and maximum IOR recovery factors are 2% and 4%, respectively.

Table 29: Worldwide subsea multi-phase pumping applications

Year	Water Depth (ft)	Field name	Comment
1992	2001	Tunisa	Subsea helico-axial multi-phase pump on Tunisia field, POSEIDON project
1994	164	Prezioso	Subsea electrical twin-screw multi-phase pump in the heavy oil Prezioso field.
1998	3838	Albacora	ESP in subsea well, Campos Basin, Albacora field, Brazil.
2000	1296	Marimba	ESP in a seafloor caisson separator,Marimba Field, Brazil.
2001	1116	Troll-C	Pilot subsea separation/boosting/injection system, Troll-C Field, Norwegian North Sea,
2005	4200	Jubarte	ESP was incorporated into subsea pumping module of heavy oil.
2006	476	Lyell	Subsea twin-screw pump installed in Lyell Field, North Sea
2007	5578	King	Subsea multi-phase pump twin-screw pump installed in King field, DW GoM
2007	476	Columba	Multi-phase pump ESP applied to subsea raw seawater injection of Columba Field in North Sea.
2007	656	Tordis	Subsea separation/boosting/injection system in Tordis Norwegian North Sea.

In-well gas lift is applied by injecting gas into the tubing as deep as possible to aerate the fluids above the injection point. This will lightens the fluid column, lower the bottom-hole pressure and increase the production. In offshore environments, most wells are drilled as deviated wells from a central location, and are tied-back via flowlines to a host facility. Deviated wells present wellbore clearance issues for both ESPs and gas lift but the latter on is preferred over ESP, as less equipment is put at risk. Load-bearing deck space requirements for generators for ESP and compressors for gas lift must be considered in developing the economic justification for artificial lift. Additional equipment and deck space may also be required to handle larger volumes of produced water resulting from artificial lift. But the gas lift has smaller producing rate potential than ESP. Gas lift becomes limited in deepwater application because of the higher operating pressure it requires. The gas lift has been widely used in shallow water Gulf of Mexico. The gas lift valves can be installed in the wells as back-up to the ESPs. The minimum and maximum IOR recovery factors are 2% and 4%, respectively based on the applications at shallow water Gulf of Mexico.

In-well ESP adds energy by increasing pressure in the tubing through an electrically driven pump. Well A-13 of Pompano, an extended-reach well to Miocene reservoir was the first well installed ESP in Deepwater GOM. The ESP was installed at Feb 6, 2005. The productivity was moderate with moderate water cut; production rate was 2,000 bopd, 2,100 bwpd, and 2.5 MMcf/d of gas before the ESP installation. Then the well production was 4,900 bopd, 5,000 bwpd, and 4.6 MMcf/d of gas. Six months later, the production reached three times the original rate and was limited only by the platform handling capabilities (Niccum et al., 2005). ESPs are highly efficient and evolving ESP technology is enabling distant located wells to be tied back to a host platform, making marginal and distant fields economical to exploit. Well RJS-211 Carapeba field was the first subsea well installation of the in-well ESP operated in 1994 (Colodette, et al. 2008) to increase the production of offshore heavy oil with large amount of water. The key feature of the ESP system is its reliability. The interventions in subsea satellite wells are not only extremely costly, but also bring management problems when production targets are not achieved. The minimum and maximum IOR recovery factors are 2% and 4%.

Subsea processing is a supplement process to allow for the efficient operation of pumps (or compressors) to operate more efficiently by reducing the hydrostatic head after removing dense water and lower the gas volume fraction. Subsea horizontal oil-water SSBI (subsea separation, boosting and injection) system might also be ranked at a high level of readiness based on the performance of the separator at Troll-C (Horn, 2002); however, the failed water injection component of a similar system installed at Tordis should be evaluated to better understand the risk associated with this system (Mogseth, 2008; Gruehagen, 2009). Five vertical anaular separation and pumping systems (VASPS) were recently installed in the Perdido deepwater development, with first production achieved in the first quarter of 2010. Perdido is located 200 miles off the Texas Gulf Coast, in 8000 ft of water, and is the first producing development from the Lower Tertiary in the Gulf of Mexico. The seafloor gas-liquid caisson separator is applied at Perdido development. Higher differential pressures are achieved with ESPs in caisson (2,300 psi).

Subsea boosting and separation projects are continuing at a fairly rapid rate, with seven projects recently installed (pending start-up) and seven projects in the manufacturing stage. These projects are as follows:

- Installed (pending start-up)
  - Vincent: Dual helico-axial pumps
  - Marlim: Twin-screw pump
  - Golfinho: Caissons with ESPs
  - Azurite: Dual helico-axial pumps

  - Parque das Conchas: Caissons with ESPs
  - Schiehallion: Dual helico-axial pumps
  - Marimba: Caisson with ESP
- Manufacturing stage
  - Espadarte: Horizontal ESPs on skid
  - Jubarte: Caissons with ESPs
  - Cascade/Chinook: Horizontal ESPs on skid
  - Barracuda: Helico-axial pump
  - Montanazo/Lubina: Centrifugal pump
  - Pazflor: Vertical separators + hybrid helico-axial pumps
  - Marlim: In-line separation

If the economic limit of water cut is set to 80%, the waterflood IORs evaluated by the sector model of Neogene reservoir range from 12-18% based on different voidage displacement of injection (Appendix A). The waterflood IORs ranges from 14.9-21.8% if the economic is re-set to 90%. The incremental oil recovery factors are between 0.1 to 2.8% (Table 51) if the pumping and artificial lift are applied to increase the water cut limit.

Future challenges in subsea processing technology are primarily associated with operating in deeper water and with longer tie-backs to host facilities, and involve hydrate management and power. There is no reported incremental oil for these applications, the possible minimum and maximum IOR recovery factors are 2% and 4%, respectively.

9.2.14 Well Technology

Wells are required for implementation of all IOR processes and therefore are enabling technology. Conventional wells are required on the basis of the trapped oil mechanisms study showing that 15% of OOIP in Neogene reservoirs is not connected to wells. This volume is typically tied up in small compartments or fault blocks where the economics of drilling a development well are marginal. Therefore, low cost wells are important alternative for improving oil recovery.

Reducing well drilling costs are typically a continuous improvement process with incremental steps achieved over many years. This is documented by the Norwegian Petroleum Directorate (NPD) in a study of IOR methods on the Norwegian Continental Shelf it was noted that much of the improvement in recovery over time is due to lower cost and improved well technology.

The UK and Norwegian North Sea is a basin with considerable history of operating wet tree wells. The NPD has noted that typically some sort of interventions is required on a subsea well every 4 years. The benefit of lower cost riserless light well intervention (RLWI) is to economically continue to operate wells longer and hence improving oil recovery. The ability to intervene in a well to keep it operation has led to prior reports showing a much reduced expected ultimate oil recovery from subsea (wet tree) developments as compared to platform developments in the North Sea. We expect that this gap is narrowing with the advances in technology for low cost well intervention.

RLWI operations are normally carried out from a dynamically positioned purpose-built intervention vessels, small semi or mono hulls to perform the wireline operations: logging, gauging, plugging, re-perforating, milling scale and various downhole mechanical works to reduce flow restrictions. The technology includes a patented lubricator system for inserting the downhole tool package through the Christmas tree and completion under full pressure.

Åsgard field (Juel, 2009) is located in the Haltenbanken area off Mid-Norway developed with subsea wells only. RLWI has been applied 23 operations in the field since 2003. The operation was performed in a HT gas condensate field with commingled production and injection strategy. The objective of the intervention was to remove a 69 ft calcium carbonate scale bridge to provide access for installation of a HPHT bridge plug and permit subsequent additional perforation.

The low cost well intervention in DW GOM can technically improve oil recovery an estimated 2-6% of OOIP.

Horizontal wells have been used in a number of deepwater GOM applications. Specifically, they are proposed as an IOR process for the Neogene to connect reservoir compartments that would otherwise require multiple vertical wells. Applications of horizontal wells have been reported at DW GOM, i.e. Europa, Ram Powell, Diana, and Kepler fields. The estimated improvement of oil recovery ranges between 2 to 6%.

9.3 *Neogene IOR Process Evaluation and Ranking*

Nineteen IOR processes are included on the list for potential use in Neogene age reservoirs. The application of each of these processes along with offshore field experience was discussed in the prior section. A number of metrics are used to evaluate the processes. These include the following:

- Minimum (P90) and maximum (P10) technical incremental recovery
- Number of target fields and the target OOIP
- Unrisked potential P90, P50, P10 incremental resource
- Technical readiness factor
- Technical readiness weighted P50 resource
- Process relative rank

Originally the team planned to determine economic incremental $/bbl for each of the IOR applications. However, the project team and the RPSEA working committee decided that economic valuation would be difficult since economics are specific to the field and facilities installation. The IOR processes are therefore discussed as concepts and their described resource potential is provided to rank the concepts.

The minimum and maximum technical incremental oil recovery was determined for each process based on worldwide experience with the method. The review of each concept in Section 9.2 provides the incremental recovery range and justification.

To determine the number of potential field applications for each of the IOR processes, the database of fields and reservoirs was interrogated with selected criteria. The criteria differ by process. For example, the criteria for selection of candidates for conventional water injection were determined as follows:

- If no existing water injection or prior injection trial
- If field OOIP is > 100 MMSTB
- If forecast RF is < 40%
- If maximum produced water cut is less than 40%
- If cumulative water-oil ratio is less than 0.20

Similar methods are used for all of the IOR processes. If a field is selected as a candidate for a specific IOR process, the field OOIP in significant reservoirs is added to create a total target OOIP for the process.

The target number of field applications and target OOIP are used to determine the IOR potential for each IOR process. The minimum, maximum, and average IOR RF is applied to the target OOIP identified to generate the range of resource potential.

9.3.1 Technical Readiness Factor (TRF)

At the suggestion of the RPSEA working committee, the DeepStar Technical Readiness Factor was selected for use on determining the risk of applying a particular IOR technology. The TRF analysis provides an unbiased foundation for risking and eventually ranking the IOR potential on the basis of readiness for implementation.

The DeepStar TRF was adapted to fit this project since it is normally applied to hardware and equipment used in the field. The TRF is an 8-level grading system where a value of TRL 0 is an unproven idea or concept up through TRL 7 which is proven and deployed technology. The DeepStar TRL categories, names and definitions are show in Table 30. Also shown are the adapted definitions used for this project to apply to IOR processes. There is a progression from TRL 0 to TRL 7 where an unproven concept is tested onshore to proven onshore followed by proven onshore and finally proven in deepwater in the environmental conditions similar to the deepwater Gulf of Mexico.

Table 30: DeepStar technical readiness factor (TRF) adapted for RPSEA 1701

		DeepStar		RPSEA 1701	
Category	Level	Name	Definition	Name	Definition
Conception	TRL 0	Unproven Idea	A technical need is identified and a concept conceived	Unproven Idea	Observed potential in core analysis or field observations but no field pilots with positive results
Proof-of-Concept	TRL 1	Proven Concept	The concept has been refined to where the basic physical properties developed and documented	Concept with Onshore Pilot / Lab Testing	Concept with lab evaluation, flow loop testing, formulation of basis of design, and possibly some field pilot testing
	TRL 2	Breadboard Demonstration	Concept is developed into an ad-hoc system to test if components work together	Onshore Pilot Field Implementation	Technology has been pilot tested and implemented to some field-wide projects with some success
Prototype	TRL 3	Prototype Tested	The technical specifications are developed further and a prototype has been developed	Onshore Proven Technology	Technology is well established and proven in onshore fields
	TRL 4	Environment Tested	The technology meets criteria of TRL3 and testing is conducted in simulated environment over its full operating range	Offshore Tested with Limited Experience	Technology has been used onshore and tested in offshore fields but with limited operational experience
	TRL 5	System Tested	The technology meets criteria of TRL4 and is integrated into its intended operating system but the test environment may not be field realistic	Offshore Proven - Different Environment	Technology is proven offshore in <1000 ft water depth and in lower reservoir pressure/temperature regimes as observed in the deepwater GoM
Field Qualified	TRL 6	Technology Deployed	The technology has been deployed in the field but has insufficient track record of reliability	Deepwater Deployed with Limited Experience	Technology tested with limited experience in the deepwater GoM. Or the technology has been successfully deployed in other deepwater basins but under different conditions
	TRL 7	Proven Technology	The technology has been deployed in the field and has successfully operated with good reliability for >10% of expected life	Deepwater Field Proven	Technology field proven in deepwater and in environmental conditions similar to those observed in the deepwater GoM

A review of the estimation of technical readiness factors for each of the 19 Neogene IOR processes is given in Table 31. For example, conventional water injection is given a TRL 7 level since it has been applied already in the number of deepwater GOM fields. Both seafloor water injection and aquifer dump flooding have been applied in a few offshore fields but none in deepwater and none in the DW GOM. Therefore, they are both ranked as TRL 4 which is offshore tested with limited experience.

Two IOR processes, hydrocarbon gas dump flooding and low-cost wells, are given a TRL 0 since they are unproven concepts. The definition of low-cost wells here is wells drilled 50% less cost than currently. This is a concept which would require a re-engineering of the way deepwater wells are drilled and/or a change in the type and cost of rig used to drill wells.

Low salinity waterflooding, although promising in core floods and early field pilots, it is ranked TRL 2 since it is still in the onshore pilot testing phase. The remainder of the IOR processes, their TRL ranking, and a discussion of the definitions for picking the level is provided in Table 31.

Table 31: Technical Readiness Factor for Neogene IOR processes

IOR Category	IOR Process	Applications	TRL	Name	Definition
Water Injection	Conventional Water Injection	Horn Mountain, DW GoM, Waterflood Performance (AAPG Bulletin, v. 91, no. 6 (June 2007). Schiehallion Field, West of Shetlands, UK (GCSSEPM, Dec. 2008). Knowledge Reservoir review of waterflood experience in DW GoM (presented at RPSEA Committee Meeting, 16	7	Deepwater Field Proven	Technology field proven in deepwater and in environmental conditions similar to those observed in the deepwater GoM
	Seafloor Water Injection	Tyrihans Field, Offshore Norway (OTC 20078) Columba Field, North Sea (SPE 109090) Barton Field, Malaysia (SPE 88568) (Evaluation study) Albacora Field, Brazil (OTC 20186) (Plan implementation)	4	Offshore Tested with Limited Experience	Technology has been used onshore and tested in offshore fields but with limited operational experience
	Aquifer Dump Flooding Injection	October Field, Offshore Egypt (SPE 112311)	4	Offshore Tested with Limited Experience	Technology has been used onshore and tested in offshore fields but with limited operational experience
Water-Based EOR	Low Salinity Water injection	Moran / North and West Semlek Fields, Wyoming (Coreflood results) (SPE 109965) Endicott Field, Alaska North Slope (SPE 113480, 2008) Coreflood Experiments (Lager et al., 2006) Coreflood Experiments (SPE 129012, Ashraf et al., 2010)	2	Onshore Pilot Field Implementation	Technology has been pilot tested and implemented to some field-wide projects with some success
	Microbial EOR	Norne Field, Norwegian North Sea: Forecast IOR = 3% of OOIP Beatrice, Ninian, Murchison Fields, North Sea: Early 1990's trials Phoenix / Mink Unit pilots, Oklahoma (SPE 27751): IOR = 0.2-1% of ROIP	3	Onshore Proven with Some Offshore Testing	Technology is being tested offshore but has mixed history of success and failurre; pick average between 4 and 2.
	Alkaline Surfactant Polymer (ASP)	Minnelusa Fm, Wyoming: Tanner, Cambridge, West Kiehl and Mellott Ranch fields (SPE 24144, SPE 113126, SPE 55633) Daqing Field, China (SPE 84896, SPE 114343) La Salinas Field, Venezuela: Offshore ASP project planning (SPE 84775)	3	Onshore Proven Technology	Technology has been pilot tested and implemented to some field-wide projects with some success
	Chemical Augmented Waterflooding	Limited recent experience of chemical flooding	2	Onshore Pilots and Field implementation	Mature technology but mixed success history, particularly on economic viability. Average between onshore proven and testing
Gas Injection	Hydrocarbon Gas Injection	Gullfaks, Statfjord, other North Sea (SPE 99546, SPE 78344, SPE 78348) Prudhoe Bay, Milne Point, and Kuparuk Fields, North Slope of Alaska (SPE 72466, SPE 89353, and SPE 113933)	5	Onshore Proven Technology	Technology is proven offshore in <1000 ft water depth and in lower reservoir pressure/temperature regimes as observed in the deepwater GoM
	Hydrocarbon Gas Dump Flooding		0	Unproven Idea	Observed potential in core analysis or field observations but no field pilots with positive results
Gas-Based EOR	Nitrogen Injection	Analysis of USA nitrogen projects and offshore designs (SPE 11902) K2 (lab test) OTC (19624) Akal Reservoir in Cantarell Complex (gas cap injection)	4	Offshore Tested with Limited Experience	Technology has been used onshore and tested in offshore fields but with limited operational experience
	CO2 Injection	Significant number of successful applications onshore US OG21 group study, Norwegian Continental Shelf Gulf Coast CO2 Experience in Sandstone Reservoirs (SPE 113368) (upper Texas Gulf Coast and along the Louisiana coast, barrier/strandplain, submarine-fan	3	Onshore Proven Technology	Concept with lab evaluation, flow loop testing, formulation of basis of design, and possibly some field pilot testing
Diverting Agents	Foam and other chemicals	Snorre Field (SPE 75157 FAWAG application)	4	Offshore Tested with Limited Experience	Technology has been used onshore and tested in offshore fields but with limited operational experience
Seperation, Pumping & Artificial Lift	Subsea Multi-Phase Pumping	Gullfaks multiphase booseter pumps (SPE 50682) Tordis, North Sea (OTC 19328, SPE 123159). The first commercial full scale subsea separation installation. By separating out water and sand at the sea floor and injecting this waste into a dump reservoir in a	7	Deepwater Field Proven	Technology field proven in deepwater and in environmental conditions similar to those observed in the deepwater GoM
	In-Well ESP	Application of ESP at Pompano. (Offshore December 01, 2003, volume 63, issure 12) Jubarte field, Campos Basin (SPE 117174) (offshore heavy oil with large amount of water.)	6	Deepwater Deployed with Limited Experience	Technology has been applied in a large number of offhore wells with both dry and wwet trees in North Sea, Brazil and GoM. Limited experience in deepwater GoM at high pressure so keep as TRL = 6
	In-Well Gas Lift	GL is not widely used in deepwater environment because of the following reasons: most wells in DW are deviated with wellbore clearance issue, GL is not ok for sand and heavy oil, the gas availability, the GL has a lower rate potential than ESP, the limit	6	Deepwater Deployed with Limited Experience	Technology field proven in deepwater and in environmental conditions similar to those observed in the deepwater GoM
	Subsea Seperation	Tordis, North Sea (OTC 19328, SPE 123159). The first commercial full scale subsea separation installation. By separating out water and sand at the sea floor and injecting this waste into a dump reservoir in a closed loop system. BC-10, Brazil (Heavy oil,	6	Deepwater Deployed with Limited Experience	Technology field proven in deepwater and in environmental conditions similar to those observed in the deepwater GoM
Well Technology	Low Cost Wells		0	Unproven Idea	Assumption: >50% cost reduction
	Low Cost Well Intervention	The North Sea (OTC 20417), Asgard, North Sea (SPE 121481)	5	Onshore Proven Technology	The technology is always evolving for different appllications. Considerable
	Horizontal Wells	Application of horizontal well at Europa, Ram Powell, Jubarte, Campos basin (SPE 117174)	6	Deepwater Deployed with Limited Experience	Technology field proven in deepwater and in environmental conditions similar to those observed in the deepwater GoM

The results of Neogene IOR evaluation are summarized in Table 32. The minimum and maximum incremental recovery factors and target OOIP are used to estimate the P90, P50, and P10 values of potential incremental barrels. The target potential numbers are not additive since the IOR processes may apply to a single field and be competing alternatives.

The technical readiness factors are used for risk weighting of the P50 IOR potential. The weighting is simply the TRL value divided by 7 or the maximum possible. Hence, the risk factor for conventional water injection is 1 while the risk factor for aquifer dump flooding is 4/7 or 0.57. The TRL risk factor is multiplied by the P50 target potential barrels to give the P50 risked IOR. Finally, the value of the P50 risked IOR is used to rank the 19 processes.

Table 32: Results of Neogene IOR evaluation and process ranking

			Technical IOR RF		Applications		Target Potential Barrels					
Process Number	IOR Category	IOR Process	Low	High	Field Count	Target OOIP of the field (MMSTB)	P90 Case (MMSTB)	P50 Case (MMSTB)	P10 Case (MMSTB)	Technical Readiness Level	P50 Risked IOR	Process Ranking
1	Water Injection	Conventional Water Injection	4%	25%	14	10,009	400	1,451	2,502	7	1,451	1
2		Seafloor Water Injection	4%	18%	18	10,338	414	1,137	1,861	4	650	2
3		Aquifer Dump Flooding Injection	4%	18%	18	10,338	414	1,137	1,861	4	650	3
4	Water-Based EOR	Low Salinity Water injection	3%	7%	26	22,344	670	1,117	1,564	2	319	11
5		Microbial EOR	1%	5%	5	7,168	72	215	358	3	92	16
6		Alkaline Surfactant Polymer (ASP)	5%	20%	7	6,481	324	810	1,296	3	347	8
7		Chemical Augmented Waterflooding	4%	16%	7	7,821	313	782	1,251	2	223	14
8	Gas Injection	Hydrocarbon Gas Injection	3%	12%	5	7,087	213	532	850	5	380	7
9		Hydrocarbon Gas Dump Flooding	3%	8%	10	4,742	142	270	398	0	0	18
10	Gas-Based EOR	Nitrogen Injection	3%	12%	8	7,970	239	598	956	4	342	9
11		CO2 Injection	3%	15%	5	1,811	54	163	272	3	70	17
12	Diverting Agents	Foam and other chemicals	1%	7%	12	12,890	129	493	857	4	282	12
13	Pumping & Artificial Lift	Subsea Multi-Phase Pumping	3%	7%	23	10,935	328	547	765	7	547	4
14		In-Well ESP	3%	7%	13	12,206	366	610	854	6	523	5
15		In-Well Gas Lift	3%	7%	21	10,506	315	525	735	6	450	6
16		Subsea Processing	2%	4%	6	5,516	110	165	220	6	141	15
17	Well Technology	Low Cost Wells	4%	9%	74	29,712	1,329	1,993	2,657	0	0	18
18		Low Cost Well Intervention	1%	4%	47	12,515	125	313	501	5	223	13
19		Horizontal / Multi-Lateral Wells	2%	9%	24	6,972	156	390	624	6	334	10

The results can first be looked at by the ranking of risked IOR potential. Water injection by conventional and the low-cost alternatives stand out as having the highest potential. These results include a number of larger Middle Miocene fields (Atlantis, Shenzi, Tahiti, and Thunder Horse) for which water injection is already tentatively planned in the development. The second group of high ranking potential IOR is for subsea pumping, electric submersible pumps, and gas lift. A third tier of IOR processes with the most risked potential includes hydrocarbon gas injection, nitrogen injection, chemical ASP flooding, and horizontal wells.

The ranking process, by risked reserves, should not be the only criteria used to consider other IOR technology. The target applications and OOIP is important even if the risk of applying the process is high. For example, low-cost wells have the largest target OOIP of nearly 30 Billion Bbl. Also, low-cost well intervention has the a large number of field applications due to the number of wet tree developments showing the importance of this technology, even though the target incremental oil potential is not high.

Low salinity water injection also has a high number of field applications and large IOR target. However, since the risk is high because this is evolving technology, it has a low risked potential ranking. It is still recommended that this IOR alternative be considered for research since the unrisked potential is so high.

9.4 *IOR Potential with Shared Infrastructure*

The field size and incremental oil potential are often too small for a single, deepwater field to carry the cost of a major IOR/EOR project. Gulf of Mexico blocks are 3 miles by 3 miles, and different operators may often compete in adjacent blocks. These impact the potential for infrastructure, pipelines and platforms, which can be shared for multiple fields. There are a large number of fields tied back to remote hosts. However, the remote host will often have been designed for the primary field development and may not have space and weight to add the facilities required for a waterflood or other incremental recovery project.

Options available to overcome these restrictions include:

1. Planning of shared facilities for new field developments and building in space and weight for maximizing life-of-field resource recovery. This most likely would require intervention from the MMS or other agency to ensure cooperation. Also, most companies prefer to better understand the subsurface performance and uncertainty prior to committing to additional capital expenditure during initial field development.
2. Cooperation for shared facilities in later field life where common benefits are observed. This option is more viable although the synchronizing the timing of needs from multiple fields can be an obstacle. However, there are regions with a high concentration of fields with similar geology and IOR needs that could share a common facility. Again, a government agency may be required to understand the needs of all field and to facilitate the interaction of companies with common potential needs operating in “focus” areas.

A few examples of areas which may have common future IOR needs are discussed below.

9.4.1 Atwater Foldbelt Area – Proximal to K2 Field

The K2 field and its reservoir performance have been discussed in earlier sections of this report. Drive energy from aquifer influx and rock compaction are limited, and the projected primary oil recovery is around 20% of OOIP. The operator and partners have been evaluating nitrogen injection and water injection schemes to increase oil recovery. Because there are space and weight limitations on the host TLP at Marco Polo field, incremental projects for K2 field will most likely need to include the construction of a new floating facility.

There are a number of Middle/Lower Miocene field developments in the area (Figure 68) which may have similar needs for the injection of water or gas and other future IOR process. Those fields include Mad Dog, Shenzi, Atlantis, Neptune, Tahiti, Knotty Head, and Holstein (younger age reservoirs). Some of these fields (Atlantis, Tahiti, and Shenzi) have already planned and designed for the potential future implementation of water injection. The Holstein field already

has implemented water injection, and BP recently announced the plans to prepare for water injection on Atlantis.

Even for those fields with existing water injection equipment (or space and weight to implement), there is potential for future shared infrastructure for gas injection, low salinity waterflooding as a tertiary recovery process, microbial EOR, or possible CO2 injection piped from shore. The biggest potential near-term is for a shared low salinity water injection supply facility for K2, Mad Dog, and Neptune fields to be used as a secondary recovery process with additional tertiary recovery benefits.

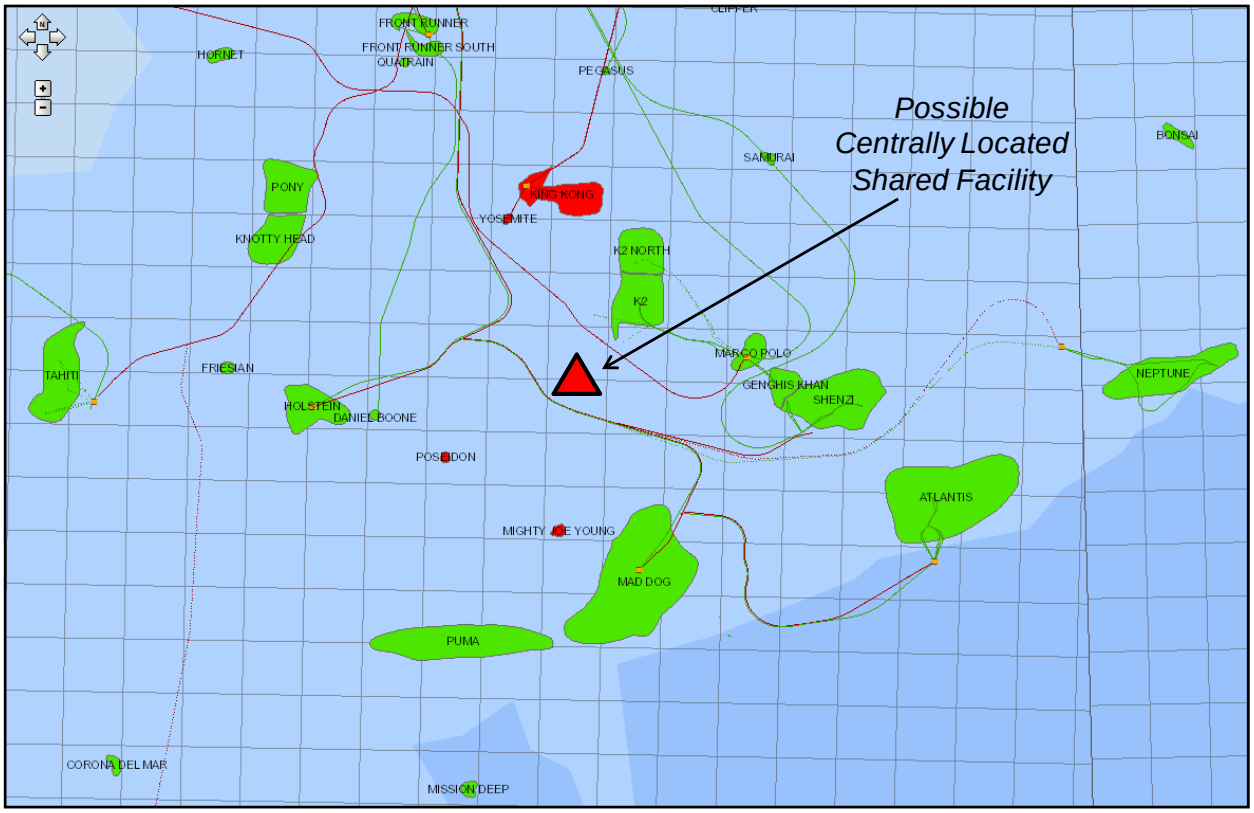


Figure 68: Atwater Foldbelt fields - potential for shared IOR infrastructure

9.4.2 Viosca Knoll – A Case for Infrastructure Sharing

Concentrated in the southern Viosca Knoll development area and in the adjacent Mississippi Canyon block is an extensive system of production facilities and product export pipelines serving a cluster of major oil and gas fields. Principal gas discoveries in the region are Virgo, Tahoe, and Prosperity. Oil fields considered in this example of infrastructure sharing are Petronius, Neptune, and Ram-Powell all situated in Viosca Knoll and, the Horn Mountain and King oil plays farther south in the Mississippi Canyon protraction area. These major oil fields are located approximately 100 to 150 miles south-east of New Orleans near the Gulf's continental shelf in water depths ranging from 1,800 to 4,000 feet. Field sites are shown in Figure 69.

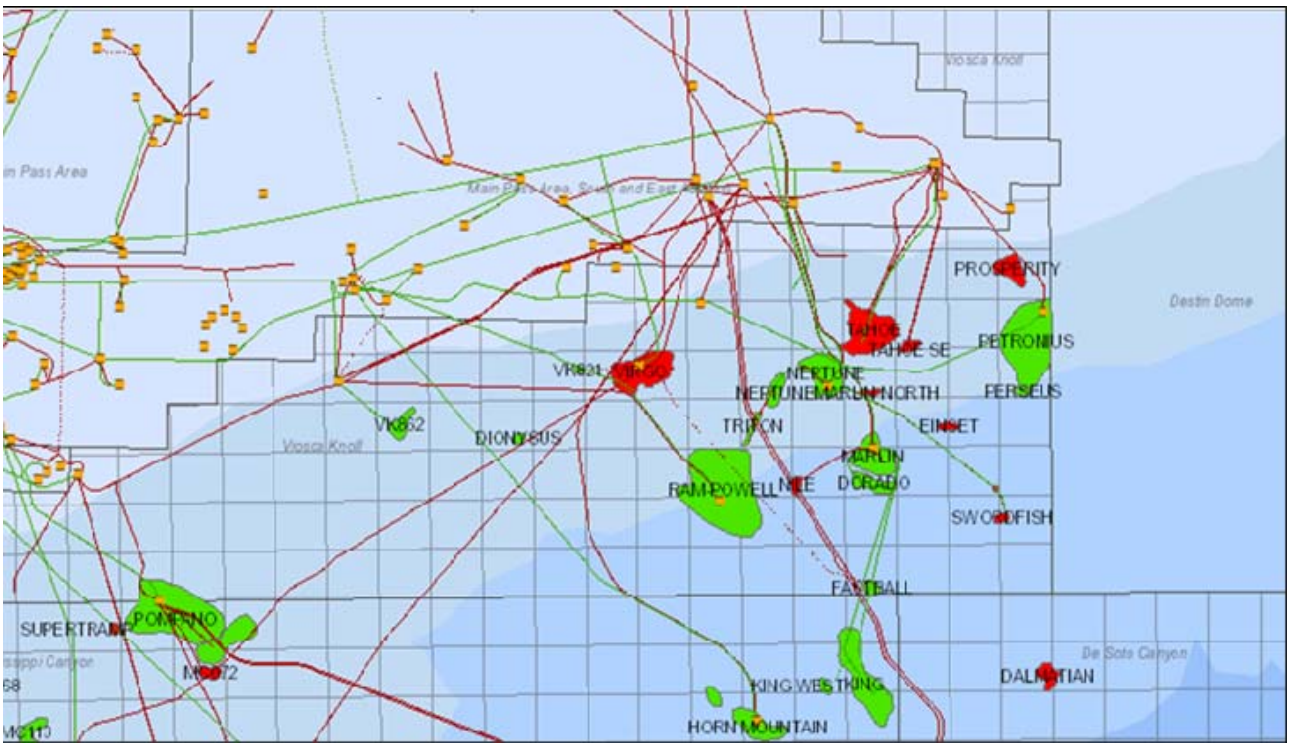


Figure 69: Major offshore fields and supporting infrastructure in the Viosca Knoll area

The oil fields under study have been on production for more than eight years. Ram-Powell and Neptune, placed on production in 1997, have estimated recoveries of 33% and 43% of OOIP, respectively. Now mature and with relatively high primary recovery factors, both projects are candidates for low salinity waterflooding as a tertiary application. Petronius, Horn Mountain, and King are newer developments with still higher recovery factors. Both Horn Mountain and Petronius were waterflooded from the onset of production. Expected ultimate recovery after secondary IOR is 40% for Horn Mountain and 57% for Petronius. Recovery at the King field is forecast at 54%. Both Petronius and Horn Mountain have upside potential using either a water-based or gas-based EOR method or some combination of these technologies. The IOR evaluation conducted here identifies low salinity water injection, MEOR, and CO2 injection as suitable techniques for Horn Mountain while CO2 flooding and MEOR can be applied to Petronius.

Operating synergies and overlapping logistics of neighboring fields warrant sharing of production facilities, injection systems, generating plants, supply lines, chemical distribution, and other material handling activities. Given that the Petronius compliant tower is closer to adjacent fields than is Horn Mountain and the fact that water injection facilities are installed topside, this location is a reasonable choice for placement of a centrally located facility. Main functions that would be managed from the expanded Petronius infrastructure would be injectant desalination, low salinity water distribution, CO2 sourcing-compression-distribution-recycling, and dosing of injection water with bacteria and nutrients in MEOR. Adapting existing equipment and installing new infrastructure at Petronius will depend on what the tower can accommodate in terms of extra weight and space requirements and the possibility of retro-fitting the original facility for a higher payload. Corrosion control will be an added expense to ensure the integrity of CO2 handling systems. Field operators participating in the alliance will need to coordinate often complex recovery strategies with those of competing reservoirs and with the central manager.

10 IOR Potential in Paleogene Fields

10.1 *Introduction*

10.1.1 Discovery of the Paleogene Horizon

The Paleogene discovery well, Trident-1, was drilled in Alaminos Canyon on the western side of the Gulf of Mexico in close proximity to the jurisdictional boundary between Mexican and U.S. territorial waters. Located about 185 miles south-east of Corpus Christi, Trident established hydrocarbon potential in the Perdido Fold Belt and marked the emergence of Lower Tertiary Wilcox targets in deepwater Paleogene exploitation (Meyer et al., 2005). While proving up significant oil accumulations, the Trident wildcat set a world record for a well sited in 9,700 feet of water and drilled to a total depth of 20,500 feet (SUBSEAIQ, 2009), (Blickwede, 2005).

Of the fourteen Paleogene discoveries, only Tiber is situated in under 5,000 feet of water, all other fields have water depths ranging from 5,900 to 9,700 feet and drilled depths from 10,200 to 27,700 feet. The Tiber discovery well has a water depth of only 4,155 feet; however, with a subsea depth of 30,900 feet, this drill site is one of the deepest in the world. The Tiber field is located about 250 miles south-east of Houston.

The resource base under study is comprised of fourteen Paleogene fields discovered from 2001 to 2009. Figure 70 is a regional map outlining the Alaminos Canyon, Keathley Canyon, and Walker Ridge protraction areas where Paleogene fields of interest are concentrated.

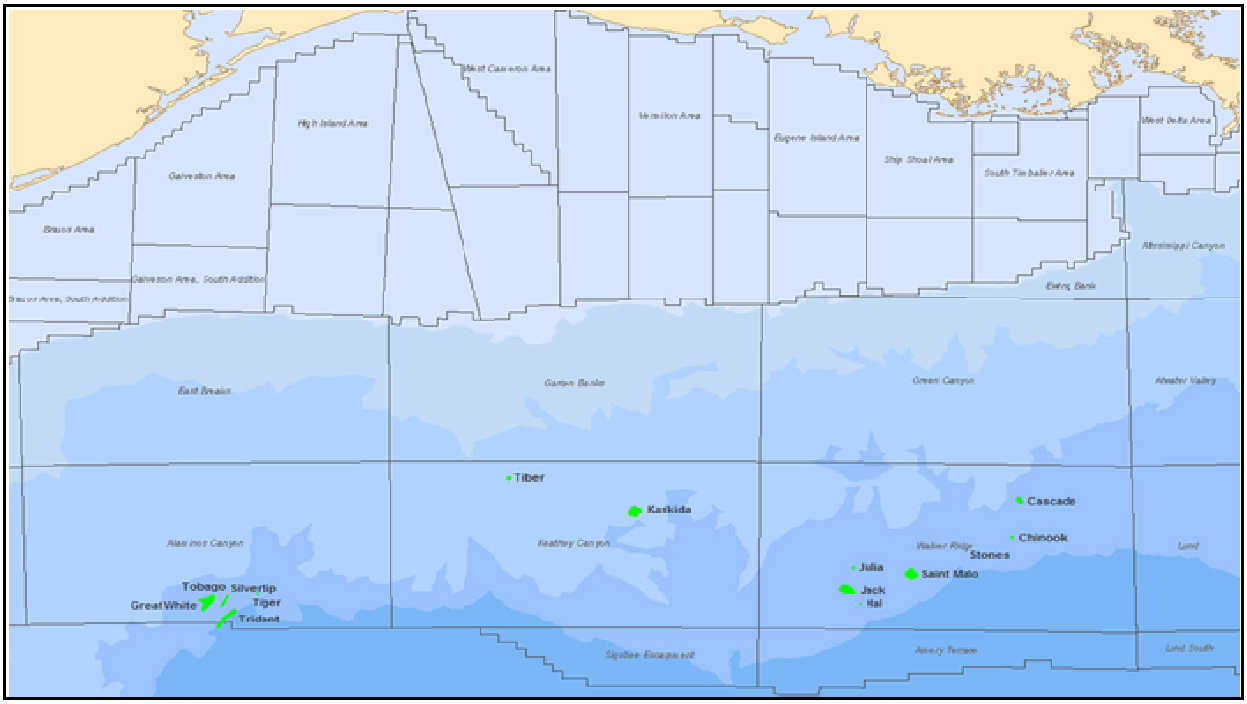


Figure 70: Deepwater GOM protraction areas and Paleogene field sites

Aggregated original-oil-in-place is estimated at 25 Billion stock tank barrels (Bstb). On an OOIP-basis, the largest field is Jack (4 Bstb), the smallest is a tie between Trident and Tobago (300 MMstb), and the average for the full field count is 1.8 Bstb. Over 50% of the resource base is

held in the four biggest fields (Jack, Saint Malo, Julia, Kaskida). Paleogene discoveries to date are much larger than most deepwater Gulf of Mexico Neogene fields. Field statistics on depth and original-oil-in-place for each protraction area are shown in Table 6.

10.1.2 Paleogene Development Experience

Opportunity realization in the deepwater Gulf of Mexico tends to follow a long and arduous course owing to initial capital requirements in the multi-billion dollar range complicated by infrastructure planning in regions distant from existing facilities and services. The deep, high-pressure and high-temperature Paleogene environment demands fit-for-purpose depletion methods and production techniques that often are neither fully understood nor validated at the field scale. These deficiencies can leave major technical gaps in a development scheme focused on recovery from the lower Tertiary Wilcox Formation.

Since 2001 when the Paleogene horizon was first encountered in the Trident exploration well, few fields have reached the implementation phase while most still remain under appraisal due to problematic sub-salt reservoir visualization and excessive well costs. The recent start-up of the Perdido spar in March 2010 attests to the many technical challenges and operating difficulties that must be solved at the design stage. Located 200 miles south of Freeport, Texas in the Alaminos Canyon block, the Perdido complex was eight years in the making and includes development from Great White, Silvertip, and Tobago fields. Great White, the main producer, was discovered in 2002 and represents about 80% of Perdido's total production (Lyle, 2007).

Table 33: Field and reservoir characteristics, Paleogene discoveries and fields

Select Paleogene Reservoir Profiles															
Protraction Area	Field	Reservoir	Water Depth (ft)	Subsea Depth (ft)	Equivalent Depth (ft)	Field Structure[5]	Average Pay Thickness (ft)	Initial Pressure	Initial Temp. (˚F)	Initial GOR (scf/stb)	Water Saturation	Porosity	Permeability (md)	Oil Gravity (˚API)	Oil Viscosity[6] (cp)
Alaminos Canyon	Great White[1]	13800	8,072	14,518	22,590	anticline	64	7,028	165	1,900	0.22	0.21	121	37	1
	Silvertip[1]	FRIO_3	9,493	13,338	22,831	anticline	64	6,537	111	2,065	0.16	0.35	2,027	37	1
	Tobago[1]	17200	9,493	17348	26,841	anticline	38	9,487	109	2,065	0.21	0.28	426	37	1
	Trident[1]	B	9,721	16097	25,818	anticline	31	8,675	132	1,700	0.54	0.25	14	40	1
	Tiger[1]	12800	9,004	12747	21,751	anticline	34	6,503	102	2,065	0.20	0.34	1,048	37	1
Keathley Canyon	Kaskida[2]		5,900	26,600	32,500	anticline			350	300	>0.20				
	Tiber[2]		4,155	30,900	35,055	anticline			350	300	>0.20				
Walker Ridge	Cascade[1]	SAND1	8,152	25,358	33,510	anticline	107	18,273	169	150	0.35	0.18	40	24	10
	Chinook[1]	SAND1	8,831	25,600	34,431	anticline	201	18,447	166	150	0.21	0.23	31	24	10
	Hal[3]		7,657			anticline			203	150	>0.2				
	Jack[1]	WILCOX_1	6,962	27,000	33,962	anticline	140	19,374	224	150	0.25	0.16	14	25	6
	Julia[4]		6,562	24,606	31,168	anticline			203	150				27	5
	Saint Malo[1]	WILCOX_1	6,991	27,154	34,145	anticline	185	19,023	225	150	0.28	0.17	14	28	5
	Stones[1]	WILCOX_1	9,571	26,826	36,397	anticline	210	19,196	199	366	0.27	0.17	30		

Notes:

1. Except where otherwise noted, information downloaded from Knowledge Reservoir's *ReservoirKB* database June 11/10.
2. As of June 11/10, no field data for Hal field recorded in the *ReservoirKB* database.

Water and total depths for Kaskida from www.offshore-technology.com, June 15/10.

Water and total depths for Tiber from www.sebseaiq.com, June 15/10.

Assuming a temperature gradient of 2˚F/100 ft, bottomhole temperature expected to exceed 350˚F.

BP describes Tiber oil as a "light crude," corresponding to an oil gravity of at least 30˚ API; value assigned to Kaskida by proxy.

A GOR of 300 scf/stb is used as a proxy.

Water saturation expected to be >0.20.

3. As of June 11/10, no field data for Hal recorded in the *ReservoirKB* database.

   Water depth for Hal from OCS report MMS 2009-016.

   Initial temperature, GOR, and oil gravity are the averages for the Walker Ridge reservoirs in this tabulation.

   Water saturation expected to be >0.20.

4. As of June 11/10, no field data recorded for Julia recorded in the *ReservoirKB* database.

   Water depth and total depth for Julia from Rigzone Jan 08/08.

   Initial temperature, GOR, and oil gravity are the averages for the Walker Ridge reservoirs in this tabulation.

   Water saturation expected to be >0.20.

5. Anticlinal structures from IHS Petroleum Frontiers, Deep-water Gulf of Mexico Wilcox Play, Berman and Rosenfield.

6. Oil viscosity estimated after Earlougher, *Advances in Well Test Analysis* (1977).

10.2 *Paleogene Reservoir and Fluid Characterization*

A geologic overview of the Paleogene age reservoirs is provided in Section 5 above.

Paleogene oil plays under study are normally discrete hydrocarbon deposits occurring over multiple, stacked turbidite reservoirs enclosed in anticlinal structures. Vertical distance to top of identified pay horizons in the various fields ranges from 18,300 feet at Great White in Alaminos Canyon to 36,400 feet at Stones in Walker Ridge.

Across the fourteen fields, porosity ranges from 16 to 36% while permeability varies from 14 to 2,207 millidarcies. These tendencies suggest reservoir quality is better than what should be observed at these excessive depths and weight of overburden. A plausible explanation for retention of porosity and permeability at levels consistent with shallower environments is the development of high pore pressures common to Paleogene reservoirs. On average, porosity is 18% with permeabilities from 10 to 30 millidarcies. Low permeabilities of 20 to 25 millidarcies in Keathley Canyon and Walker Ridge fields reflect pore narrowing from cementation and quartz overgrowths.

The crude quality for most deepwater oils contains moderate sulfur ranging from 0.5 to 2.0 wt% (Anderson et al., 2003). Gravity for Paleogene crude is a spread between heavy oil at 19° API to light oil with an API of 40°. Oil viscosity estimates are rather small being in the 1 to 11 cP range though when in conjunction with overpressured formations, higher viscosities in the 5-15 cP range would be expected.

Reservoirs in the Perdido Fold Belt differ materially from the Paleogene reservoirs in Keathley Canyon and Walker Ridge due in part to their shallow depth below mud line. For example, the main pay at Great White field, the Upper Wilcox, has characteristics of more similar to Neogene reservoirs (high GOR, high API, good permeability and low oil viscosity). Good reservoir quality is reported for Paleogene fields located in the Alaminos Canyon area outside the perimeter of the salt canopy. Average porosity and permeability for the five Alaminos Canyon fields are 29% and 727 millidarcies, respectively. Crude oil characteristics are also more favorable with an average oil gravity of 38 °API and an average oil viscosity of 1 cP.

Over-pressurized reservoir systems are generally undersaturated as original pressure far exceeds bubble-point conditions. As such, the lack of both a free gas cap and a sufficiently large and active water drive is an approximate indicator of poor reservoir energy at the onset of primary depletion. Fluid expansion is the main displacement mechanism during pressure drawdown to the bubble-point after which a solution gas drive becomes active. However, the effectiveness of gas coming out of solution is in line with a reservoir's gas-to-oil ratio. The oils of Keathley Canyon and Walker Ridge have low GOR, are highly undersaturated and as a result have a moderately high initial oil viscosity with values from 5 – 15 cP. The vertical depth of reservoirs in these protraction areas is more than 32,000 feet. As fluids are withdrawn and pore pressure is unable to withstand the weight of overburden, rock compaction will augment the expulsion of oil via fluid expansion and solution gas.

Paleogene fields in Alaminos Canyon are expected to perform better under primary depletion owing to higher energy available from solution gas drive. The average gas-to-oil ratio is 1,960 scf/stb, a five-fold difference over the highest GORs reported for fields in the other two protraction areas.

Unprecedented high-pressure and high-temperature (HP-HT) conditions in deep Lower Tertiary Wilcox targets with large overburden are defining characteristics of a typical Paleogene reservoir. Excessive initial pressure (> 19,000 psi) and temperature (> 220 °F) are reported for a Jack reservoir. Temperatures up to 350 °F have been inferred for Tiber and Kaskida

reservoirs, assuming a regional temperature gradient of 2 °F per 100 feet; however, this estimate may be high due to the potential heat shielding of the salt canopy in the area.

10.3 *Field Analog Investigation*

10.3.1 Reservoir Analog Database for a Typical Paleogene Play

The only documented examples of production from deepwater Paleogene reservoirs in the Gulf include a 2006 flow test of the Jack #2 well in Walker Ridge at more than 6,000 barrels of crude oil per day, and the first commercial oil production from the Perdido Project (Alaminos Canyon) in early 2010. Several months of production history from Great White, though valuable as a confirmation of reservoir quality and reserves potential in Lower Tertiary horizons, is too short a period of field experience to distill lessons learned to other Paleogene prospects that remain in the appraisal stage. Without substantial knowledge transfer to validate field depletion strategies, operators are left to rely on analogies made with reservoirs outside the Paleogene exploitation arena.

Therefore, a search for suitable analogs was undertaken. A reservoir analog database for a typical deepwater Gulf of Mexico Paleogene oil play enables decisions to be made around field design and strategic planning. Confidence in drawing parallels from the analog to a Paleogene field is improved through de-risking of assumptions assigned to the reservoir of interest. Moreover, a comprehensive knowledge base provides not only empirical evidence of viable operating techniques but an equally important playbook of failed methods that should be re-assessed and/or avoided in future field scenarios.

10.3.2 Survey Method and Selection Criteria

Public domain technical reports and journals were surveyed for world-wide analogs closely matching the properties of a typical Paleogene reservoir (Table 34). Goodness-of-fit is based on the premise that similar reservoir features and properties yield the similar dynamic behavior. The usefulness of the principle of analogy in reservoir management is twofold. First, similar methods tend to work on objects with matching characteristics. Second, incompatible actions can be avoided. The primary analog selection criteria are physical attributes and depletion strategy, with a secondary emphasis on the duration of field experience and information density.

Candidacy for reservoir analog was judged on four main points of comparison ranked in order of importance in the screening process: burial depth, depositional setting, similar reservoir properties and implementation of a water injection scheme. Burial depth relates to diagenetic control on porosity, formation stress, and permeability and is of primary importance. Table 35 outlines the prioritized selection criteria on which this survey methodology is based.

Table 34: Average properties of Paleogene fields and discoveries

Area	Water Depth (ft)	Subsea Depth (ft)	Avg. Pay Thickness (ft)	Initial Pressure	Initial Temp(°F)	Initial GOR (scf/stb)	Porosity	Perm. (md)	Oil Gravity (API)	Oil Viscosity (cp)
Alaminos Canyon	9,000	5,000	120	8,000	120	2,000	0.30	800	38	1
Keathley, Walker Ridge	5,000	20,000	1,000	19,000	240	250	0.12	15	29	5

Table 35: Survey method and selection criteria for reservoir analogs

Survey Method and Selection Criteria for Reservoir Analogs		
Point of Comparison	**Order of Importance**	**Selection Criteria**
Sediment maturity / diagenesis	Priority 1	Equivalent depth to pay
Geology	Priority 2	Depositional settings and lithofacies
Fluid flow	Priority 3	Tight formation, low permeability to oil
Water injection applications	Priority 4	Positive response to waterflood and measurable performance

10.3.3 Qualifying Analogs

A broad search framed by the prioritized screening rules produced six candidates for reservoir analog. Three of the six fields identified are offshore entities, two are onshore, and the last is a hybrid structure that spans both environments and has been developed from land and sea. Representing major petroleum resource provinces from around the world are the Barracuda field (Campos basin), the Forties field (North Sea basin), the Clair field (Shetland Islands area), the Elk Hills field (San Joaquin basin), the Wilmington field (Los Angeles basin), and the Forest Reserve field (Southern basin, Trinidad). Alignment between the analog family and a typical Paleogene reservoir is strongest on the point of geology as most of the candidates are turbidite sandstones occurring in anticlines that originated from deltaic depositional systems. Priority 2 is readily satisfied by the fact that Forties, Barracuda, Wilmington, and Elk Hills belong to the world's top four turbidite basins having the largest recoverable oil. While the same structural development and geological features are a compelling argument for analogy, no examples could be found that met the excessive water depths of Paleogene discoveries. Equivalent depth for a typical Paleogene reservoir is pegged at 25,000 feet. Distance to pay is so extreme that the best-fit deepwater analog is the Barracuda field where equivalent depth is a mere 12,000 feet. At less than half the targeted depth, the precedence for alignment around Priority 1 simply does not exist.

Specialized drilling and operating expertise demanded by deep, high pressure-high temperature, and tight conditions that typify Paleogene plays underscores the unique and complex circumstances of frontier deepwater environments in the Gulf of Mexico. A lack of previous field experience in harsh reservoir settings imposes restrictions on the few instances that may serve as a predictive tool. Confidence in patterning Paleogene reservoirs after a qualifying analog family depends on the strength of observed parallels as well as a sufficiently long and documented depletion period. Without reasonable similarity in the deepwater situation or alternatively some overlap in equivalent depth, the choice of an analog will invariably be less than perfect. This is not to say that knowledge transfer from imperfect candidates is unwarranted, rather, these analogies must be tempered by examples that do not fully duplicate excessive Paleogene conditions. At best, the short-list can be ranked on the basis of qualification by evaluating how each candidate measures up to the prioritized selection criteria.

The candidates as a group are not well matched to the HP-HT signature of Paleogene reservoirs. Individually, the Wilmington field, discovered in 1932, is quite shallow at an equivalent depth of 2,550 feet. The reservoir is a turbidite sandstone with a permeability of 38 millidarcies and was deposited as a submarine fan sequence. A very low initial reservoir

pressure (~1,200 psi) and over twenty years of production without pressure maintenance has caused surface subsidence (Mamora et al., 2000). Water injection applied after this long primary period was aimed more at mitigating further compaction than as an IOR technique to augment reservoir energy. Attention was given to various steam injection methods as Wilmington oil is heavy at 14° API. Absence of good production practice in reservoir management explains in part why only 29% of the field's nine billion barrels of original-oil-in-place has been recovered (Clarke et al., 2004).

The Clair field, a 1977 discovery, is deeper at 6,530 feet, has lighter oil, and a development plan that included an early water injection program. Original reservoir pressure is 2,700 psi and matrix permeability is 30 millidarcies. The Devonian reservoir rock is much older than Paleogene age and the non-marine, fluvial-lacustrine setting produced continental not turbidite sandstones. A lithology and diagenetic pathway unrelated to turbidite deposition suggest a different regime for porosity-permeability development and flow behavior. The expected recovery factor with water injection is only 14% (Clifford et al., 2005; Wylde et al., 2005).The four analog fields, Barracuda, Forties, Elk Hills and Forest Reserve, share many attributes and development features, a commonality that overlaps the Paleogene counterpart but fails to match equivalent depth stipulated in Priority 1. The shortfall with respect to the Paleogene model is compared across the analog family in Table 36. Nonetheless, all candidates are notably aligned on turbidite geology, low permeability, and water injection treatment thereby fulfilling the other three selection criteria.

10.3.4 Screening Outcomes

Wilmington and Clair fields have some degree of alignment based on the prioritized screening criteria but markedly diverge from the Paleogene model on key points of comparison. As such, they are deemed outliers and removed from the class of qualifying analogs. Both Wilmington and Clair, however, contain numerous fault blocks and the development technique employed could lend itself to managing potential Paleogene compartmentalization.

The remaining contenders - Barracuda, Forties, Elk Hills and Forest Reserve, share many attributes and development features, a commonality that overlaps the Paleogene counterpart but fails to match equivalent depth stipulated in Priority 1. The shortfall with respect to the Paleogene model is compared across the analog family in Figure 71. Nonetheless, all candidates are notably aligned on turbidite geology, low permeability, and water injection treatment thereby fulfilling the other three selection criteria. A location map of the four qualifying analogs is given in Figure 72. Screening outcomes are indicated in Table 36.

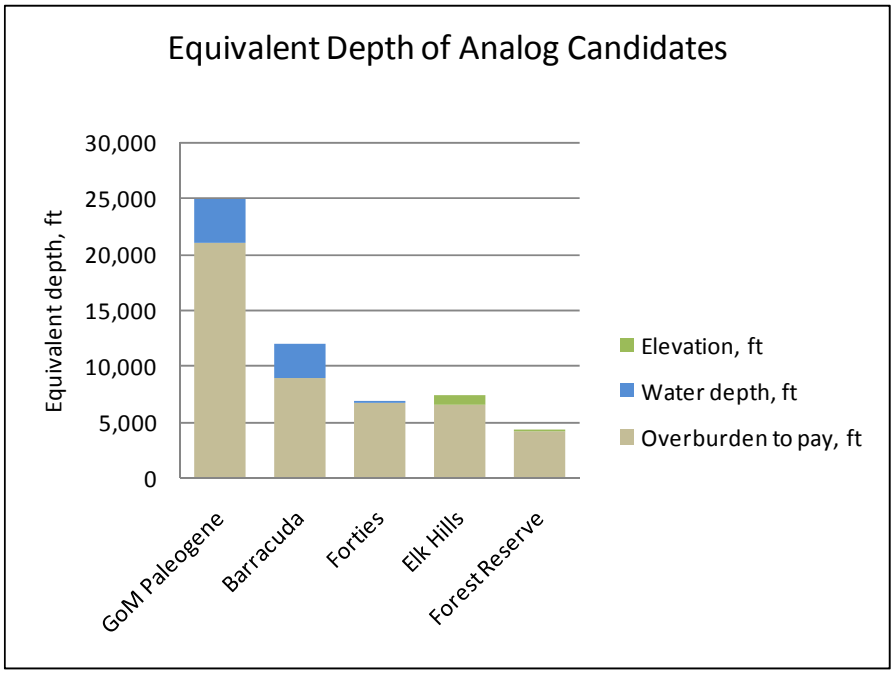


Figure 71: Equivalent depths of Paleogene analogs

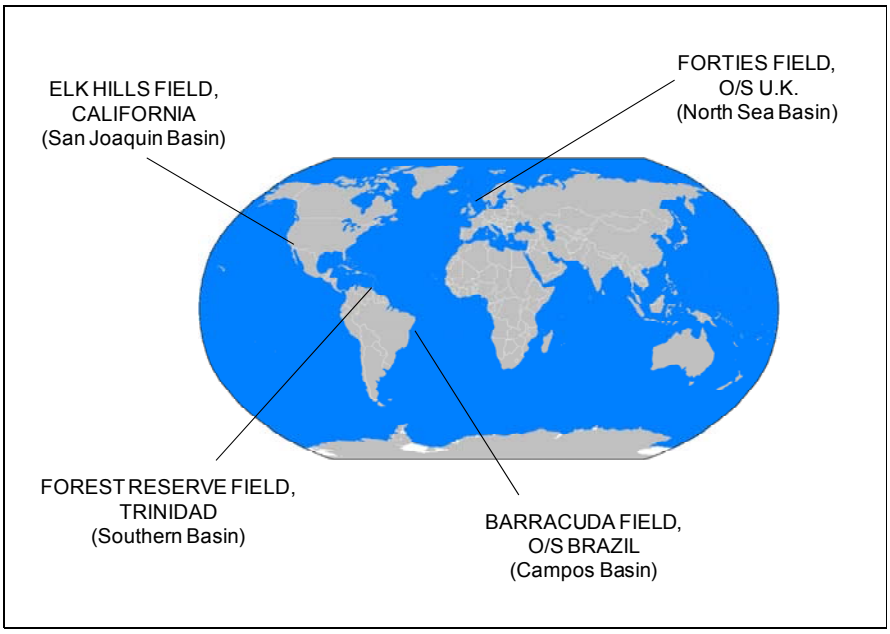


Figure 72: Location of Paleogene analogs

A comprehensive analog database was built, compiling additional information on the qualifying fields for a detailed comparison with the typical Paleogene play. Raising the granularity on analog signatures follows from the selection criteria being satisfied by basic analogies. A deeper understanding of the relationship between Paleogene reservoir and field analog behaviors is afforded by an extended study encompassing reservoir conditions and properties, displacement mechanisms, recovery methods, formation architecture, rock composition, operating technology, and depletion performance. For each of the qualifying analogs, field demographics and geology are summarized in Table 37, volumetrics and recovery factors in

Table 38, reservoir conditions and properties in Table 39, reservoir structure, lithofacies, and mineralogy in Table 40, and depletion performance in Table 41.

Table 36 through Table 41 were populated by reservoir data and other field statistics derived from the following sources:

- Barracuda field (Bacoccoli et al., 1988), (Assis et al., 1998), (Alves et al., 2005), (da Costa Filho, 2005), (Campagnolo et al., 2000), (Farias et al., 2010), (Euphemio et al., 2009), (Drilling Contractor, 2002).
- Forties field (Jennette et al., 2000), (Simpson et al., 1991), (Leighton et al., 2001), (Brown et al., 1991), (Brand et al., 1996), (Chesterman et al., 2009), (Hillier et al., 1978), (Vaughan et al., 2007), (Emery et al., 1993).
- Elk Hills field (Ezekwe et al., 1991), (Starcher et al., 1996), (McJannet, 1996), (Dickinson et al., 2005), (Walker et al., 2002).
- Forest Reserve (Hosein, 1996), (Wattley, 1976), (Mohammed-Singh et al., 2006), (Russell, 1988), (Wach et al., 2008), (Kuuskraa et al., 2006), (Bisson et al., 2004).

Table 36: Qualifying Paleogene analogs and screening outcomes

Qualifying Paleogene Analogs and Screening Outcomes					
Selection Criterion	**Gulf of Mexico Paleogene Play**	**Barracuda Field**	**Forties Field**	**Elk Hills Field**	**Forest Reserve Field**
Priority 1 Equivalent depth, ft	25,000	12,010	6,909	7,400	4,215
Priority 2 Geology	Turbidite sandstone (interbedded sands and shales)	Turbidite sandstone	Turbidite sandstone	Turbidite sandstone	Turbidite sandstone
Priority 3 Low permeability to oil, md	15	66	31	2	35
Priority 4 Undergone water injection	No	Yes	Yes	Yes	Yes

Table 37: Field demographics and geology of Paleogene analogs

FIELD DEMOGRAPHICS AND GEOLOGY OF PALEOGENE ANALOGS

Typical Gulf of Mexico Paleogene Play	Features / Reservoir & Fluid Properties (points of comparison)	BARRACUDA FIELD (Campos Basin)	FORTIES FIELD (North Sea Basin)	ELK HILLS FIELD (San Joaquin Basin)	FOREST RESERVE FIELD (Southern Basin)
	Field Demographics				
offshore GoM	Location	offshore Brazil	offshore U.K.	onshore California	onshore Trinidad
2001	Discovery year	1989	1970	1941	1914
0	Elevation, feet	0	0	900	15
4,000	Water depth, feet	3,045	250	0	0
21,000	Average depth of pay, feet	8,965	6,659	6,500	4,200
25,000	Total equivalent depth, feet	12,010	6,909	7,400	4,215
1,000	Thickness of pay, feet	824	614	450	260
	Geology				
Paleogene	Age of deposits	Oligocene, Eocene, Paleocene	Paleocene	Miocene	Miocene
submarine fan	Depositional setting	submarine fan	deltaic fan sequence	pelagic & terrigenous	deltaic
turbidites (interbedded sands & shales)	Lithology	turbidite sandstones	turbidite sandstones	turbidite sandstones	turbidite sandstones
consolidated	Rock texture	friable; partially consolidated	poorly consolidated	consolidated	unconsolidated but not cemented
Wilcox	Target zone	MRL330, ENCOBR	Forties	Main Body B	Upper Cruse

Table 38: Volumetrics and recovery factors of Paleogene analogs

VOLUMETRICS AND RECOVERY FACTORS OF PALEOGENE ANALOGS

Typical Gulf of Mexico Paleogene Play	Features / Reservoir & Fluid Properties (points of comparison)	BARRACUDA FIELD (Campos Basin)	FORTIES FIELD (North Sea Basin)	ELK HILLS FIELD (San Joaquin Basin)	FOREST RESERVE FIELD (Southern Basin)
	Volumetrics & Recovery Factors				
250	Original Oil-in-Place, MMstb	2,540	4,000	530	36
to be determined	Recovery factor, %	32	65	40	46
various	Recovery mechanism	solution gas	bottom aquifer drive	solution gas, partial water drive, gravity drainage	solution gas, gravity drainage
to be determined	Secondary/IOR/EOR	seawater injection	peripheral seawater injection	peripheral to pattern waterflood, gas injection	gas injection, waterflood, CO_2 flood

Table 39: Reservoir conditions and properties of Paleogene analogs

RESERVOIR CONDITIONS AND PROPERTIES OF PALEOGENE ANALOGS

Typical Gulf of Mexico Paleogene Play	Features / Reservoir & Fluid Properties (points of comparison)	BARRACUDA FIELD (Campos Basin)	FORTIES FIELD (North Sea Basin)	ELK HILLS FIELD (San Joaquin Basin)	FOREST RESERVE FIELD (Southern Basin)
	Initial Reservoir Conditions				
20,000	Pressure, psia	4,980	3,230	3,150	2,200
241	Temperature, °F	165	205	210	130
36	Water saturation, %	40	23	39	27
250	Gas-oil-ratio, scf/stb	466	313	930	400
1,239	Saturation pressure, psia	2,845	1,196	2,976	1,500
yes	Over-pressured ?	no	no	no	no
	Reservoir Rock Properties				
12	Porosity, %	29	27	20	31
15	Permeability to oil, md	66	31	2	35
4.5	Rock compressibility, x E-06 psi^{-1}	3.2	11.8	5.0	3.0
	Reservoir Fluid Properties				
29	Oil gravity, °API	24	37	36	25
5	Oil viscosity, cp	3	0.8	0.4	13

Table 40: Reservoir structure, lithofacies, and mineralogy of Paleogene analogs

RESERVOIR STRUCTURE, LITHOFACIES, AND MINERALOGY OF PALEOGENE ANALOGS

Typical Gulf of Mexico Paleogene Play	Features / Reservoir & Fluid Properties (points of comparison)	BARRACUDA FIELD (Campos Basin)	FORTIES FIELD (North Sea Basin)	ELK HILLS FIELD (San Joaquin Basin)	FOREST RESERVE FIELD (Southern Basin)
sheet sands of Wilcox turbidite trend	Structure	lenticular channel sands	anticline	anticline	anticline
faulting	Compartmentalization Risk	some sealing faults interpreted	minor faulting	few significant faults	unknown
fine-grained siliciclastic turbidites dominated by quartz, feldspar, and clays; cementation from quartz overgrowths, chlorite clay, carbonate minerals	Lithofacies & Mineralogy	siliciclastic turbidite sandstones intercalated with shales and marls; sandbodies low in clay	turbidite sandstones dominated by quartz, feldspars and lithic fragments; detrital illite, chlorite and hematite coatings are common; some calcite infill	feldspathic, clay-rich turbidite sands; 10-35% illite/smectite clay content	fine-grained turbidite sandstone containing some silt and swelling clay; deltaic sands without diagenetic cements

Table 41: Depletion performance for Paleogene analogs

DEPLETION PERFORMANCE FOR PALEOGENE ANALOGS				
points of comparison	BARRACUDA FIELD (Campos Basin)	FORTIES FIELD (North Sea Basin)	ELK HILLS FIELD (San Joaquin Basin)	FOREST RESERVE FIELD (Southern Basin)
Primary oil recovery - duration - recovery factor	 1997-2004 4%	 1975 1%	 1976 12%	 1933-1960 21.3%
Secondary oil recovery - duration - recovery factor - method	 2004-present 28% sea water injection	 1976-present 64% sea water injection	 gas injection 1976-1988 (ineffective) waterflood 1978-present 28%	 gas injection 1956-1977 20% waterflood 1974-1980 0.40%
Enhanced oil recovery - duration - recovery factor - method	 ---	 ---	 ---	 1986-2003+ 4.7% CO_2 flood
Estimated ultimate recovery	32%	65%	40%	46%
Production technology	acidizing	acidizing	hydraulic fracture stimulation, fracture height control, acidizing	gravel pack completion
Recovery issues	sand production; barium/strontium sulfate scaling	sand production; barium sulfate scaling; $CaCO_3$ deposition in gas-lifted wells	scale deposition in gas-lifted wells; compatibility of injection & formation waters and rock geochemistry; clay plugging	by-passing of oil from early water breakthrough; CO_2 channeling due to excessive rates; clay plugging

10.3.5 Analog Limitations

During the early stages of deepwater exploitation in the Gulf of Mexico when development is sparse and production experience begins to emerge from learning trials, the analog approach provides a much needed companion knowledge base for rationalizing development strategy. Performance histories, operating styles, and lessons learned from the analog family enable robust decision-making capability through proxy-driven analyses. Technology transfer from reservoir analogs is a de-risking opportunity for Paleogene field conceptualization such that the aggregate experience in the analog family both in actual recovery management and production technology design and implementation, can reduce some development uncertainties in the play of interest. A critical requirement in the analog exercise is concluding the extent of this window of opportunity for the purpose of defining where and when equivalences can be drawn. Identifying operating mistakes and incorrect premises in the analogs and their avoidance are equally if not more important.

The scope of application is set by how well the suite of analogs is aligned to the Paleogene model. In the case of depth or the high pressure-high temperature conditions, the analog family falls short of an ideal match. Ranking the individual analogs with respect to equivalent depth demonstrated the Barracuda field to be the closest of the analogs at 12,000 feet. Even with good alignment on geology, permeability and a waterflooding procedure, the Barracuda analogy has limited justification and should be used with caution. Barracuda, which represents the

offshore fields in the Campos basin, is neither abnormally pressured nor influenced by a dominant, overlying layer of allochthonous salt as is seen in the Gulf. Without a correspondence, these two features alone detract from an otherwise compelling analogy.

The Barracuda development nevertheless has distinguished itself as a leader in offshore field operations, infrastructure, and effective logistics. On the production side, the Brazilian example has deployed numerous leading-edge operating techniques from horizontal well control to subsea oil-water separation. Table 42 is a catalog of operations-based applications conducted at experienced analog fields including Barracuda which has been ranked highest overall in the analog family. Again, the transfer of appropriate, analog-proven technologies to a Paleogene field design concept and customization to Gulf of Mexico deepwater specifications can mitigate exploitation risks in less established operating environments.

Table 42: Technology transfer from Paleogene analog family

TECHNOLOGY TRANSFER FROM PALEOGENE ANALOG FAMILY	
Application / Technique	Experienced Analog
Surface infrastructure - FPSO	Barracuda
Artificial lift - gas lift	Barracuda, Forties, Elk Hills
Well completions – wet trees	Barracuda
Well control – horizontal multilaterals	Barracuda
SCADA – permanent downhole gauges	Barracuda, Forties
Stimulation – acidizing	Barracuda, Forties, Elk Hills
Injectant – sea water treatment	Forties
Subsea oil-water separation	Barracuda
Depth-migrated seismic/imaging	Barracuda
Sand contention	Barracuda, Forties
Scaling inhibition	Barracuda, Forties, Elk Hills
SRB-H_2S-Fe_xS_y control	Elk Hills
EOR – CO_2 flooding	Forest Reserve
Gas recycling (contra-indication)	Elk Hills

10.4 *Expected Performance and Recovery Factor*

10.4.1 Depletion Mechanisms and EUR

Primary recovery mechanisms for a typical Paleogene play are fluid expansion and rock compaction. The potential for aquifer influx is an uncertainty and in most cases cannot be relied upon for providing significant drive energy. Although a consolidated rock texture fortified by cementation suggests a competent formation under normal conditions, the combined water column and weight of overburden at an overall depth of 25,000 to 35,000 feet would likely crush weaker zones in the reservoir when fluids are withdrawn. Sand produced with the hydrocarbon stream upon matrix breakdown can improve permeability but this advantage is short-lived and eventually the volume of sand entering the wellbore will impede oil flow.

Abnormal pressure-temperature profiles, uncommon reservoir depths, lower than normal stress gradients, and tight formations with low permeability to oil have the cumulative effect of

downgrading reservoir quality in Paleogene plays, especially the fields to the east of Alaminos Canyon. Depletion performance under primary means of production is understandably on the low side of the empirical recovery factor range. An expected ultimate recovery (EUR) of 10% is predicated on large oil volumes lost to various trapped oil mechanisms.

10.4.2 Formation Uncertainties

Principal subsurface risks are porosity, permeability, reservoir continuity. Porosity is inversely related to depth and permeability varies exponentially with porosity. Paleogene reservoirs have retained a higher than normal porosity for deep horizons with an average of ~18% for Keathley Canyon and Walker Ridge area. The formations are tight as expected (average k is 26 md). Permeabilities for reservoirs in Alaminos Canyon are dramatically higher (average k is 727 md) and are more characteristic of Neogene plays.

Geomechanical uncertainties focus on leakage along fault blocks caused by high-pressure situations and fracture permeability systems created by the northwest-southeast regional fracture trend. The azimuth direction of natural fractures has a bearing on displacement and sweep efficiency.

In addition to sealing faults, reservoir compartmentalization in Paleogene-age formations is associated with long intervals of interbedded sandstones and shales with expected occurrences of impermeable calcite streaks. Laterally extensive indurations and other barriers to flow discretize the producing interval into a series of stacked reservoirs. Variations in both lithology and permeability render only moderate net-to-gross ratios in the order of 60% or less possibly creating the need for independent exploitation of multiple pay zones. The likelihood of water-bearing sands interspersed within complex turbidite geologies also requires special techniques to manage channeling and early break-through in very heterogeneous formations.

Type logs for wells in the Great White, Upper Wilcox main pay, and the Jack field Lower Wilcox main pay are shown in Figure 73. The two reservoirs are compared to show the gross thickness and net-to-gross (NTG) sand variation. The Jack #1 well log depicts an arrangement of poorer quality stacked reservoirs corresponding to the Wilcox 1 oil reservoir. There is an additional Wilcox 2 reservoir below with a similar stacking of inter-bedded sands and shales over a large gross interval.

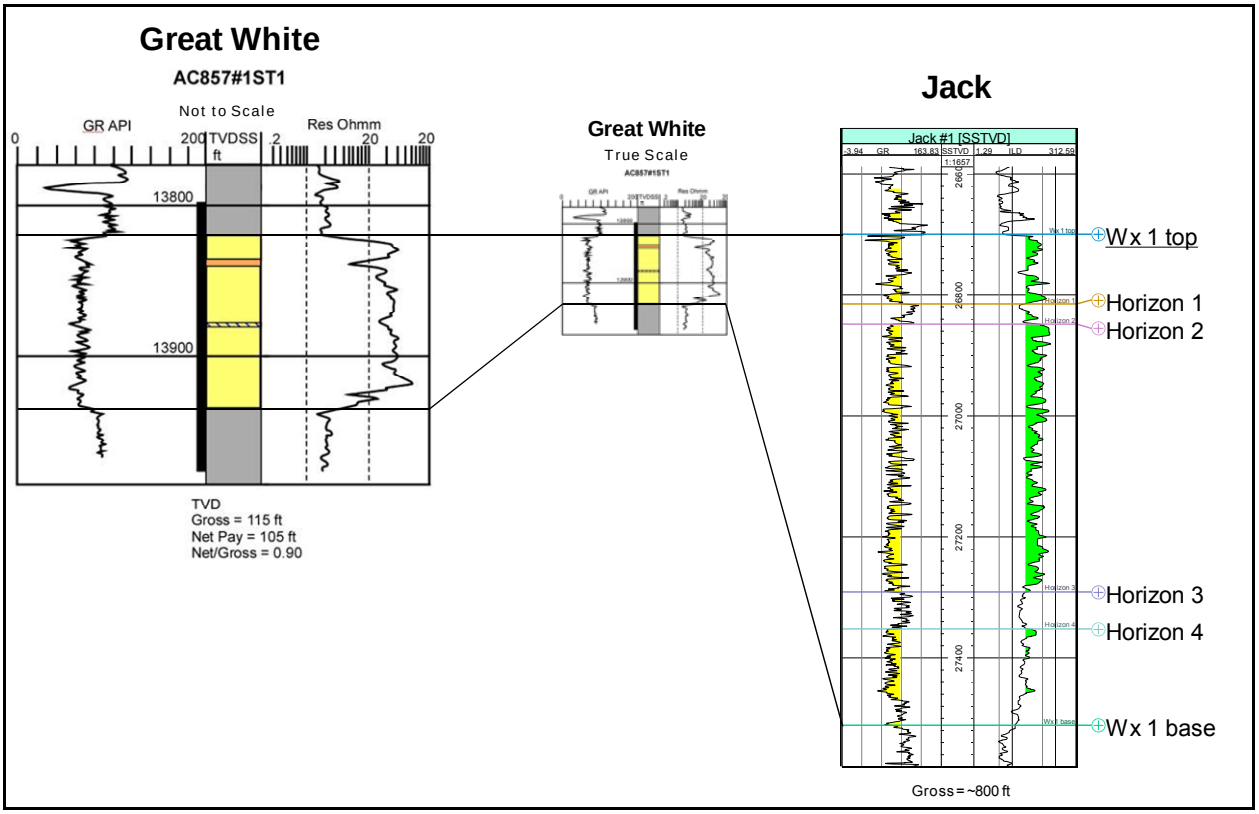


Figure 73: Type logs from Great White and Jack fields

10.4.3 Well Deliverability and Estimated Oil Rate

Productive capacity of a typical Paleogene well is modeled after the Jack #2 extended well test conducted in 2006. Performance was tracked for Jack #2 over a period of 23 days during which the reported flow rate was 6,000 barrels of crude oil per day. The test targeted two zones in the Wilcox 1 trend totaling nearly 445 feet of pay (Rains, 2005). Average reservoir properties of permeability 15 mD, oil viscosity of circa 5 cP, and the net pay reported above are used to estimate a well productivity index (PI) for the tested well of 1.0 Bbl/d/psi. The Jack PI is assumed to represent the capability of deepwater Keathley Canyon and Walker Ridge Paleogene wells and is assigned to the group as a proxy.

A Neogene example from Genesis field (Pourciau et al., 2005) is used for comparison. The Genesis example achieved a peak rate of 22,400 BOPD with a drawdown of ~ 250 psi giving an initial PI of 89.5 Bbl/d/psi. Therefore, comparative Paleogene wells may have initial productivity 70 – 100 times lower than what is typically observed in Neogene reservoirs. Oil rates at the start of primary recovery will tend to be very high from release of overpressure but will quickly fall as permeability impedance begins to dominate the flow regime.

10.4.4 Waterflooding Potential

Water injection programs will be difficult to execute in tight, abnormally-pressured Paleogene reservoirs. The key driver in a successful waterflooding operation is sufficient injectivity to overcome low permeability and strong initial back-pressure at the sand face. Conformance control is a prime concern in heterogeneous intervals several hundreds of feet thick where highly conductive water sands may be interbedded with pay. Significant water zones contained within productive horizons may call for water shut-off techniques to manage the outflow from

these multiple layers. Reservoir compartmentalization from faulting and the presence of stratigraphic barriers impose limits on water drive sweep efficiency.

Despite many drawbacks that tend to oppose the implementation of a waterflood, Paleogene reservoirs are candidates for water injection programs und the rules of good production practice. The high initial pressures of up to 19,000 psi coupled with low saturation pressures provide some leeway for commencement of pressure maintenance. Adding energy to the reservoir through injected water should begin just before drawdown reaches bubble-point conditions. Injectivity will improve but at the expense of over-pressurization. There are benefits of both lower oil viscosity and increased oil volume from expansion for delaying the start of injection to lower pressures. Avoidance of severe sub-zone differential pressure also factors into the exact timing for pressure support.

Structural elements amenable to waterflooding recovery technology offset some of the problematic features of Paleogene reservoirs if leveraged properly in the project design. Gravity drainage enhancement is possible in deposits with sharp dip whereby oil is mobilized by a density difference between the injectant and the reservoir oil. Strata with substantial dip occur in all Paleogene anticlines. Natural vertical fracture systems in anticlines elongated by compressional forces promote piston-like frontal advance along the main axis of the structure.

Recovery schemes for the Perdido operation and the planned joint development of the Jack and Saint Malo fields in Walker Ridge confirm waterflooding potential in Paleogene reservoirs. The subsea installation for Alaminos Canyon's Great White-Silvertip-Tobago venture includes one water injection line and three water injection trees. Although production is not scheduled to begin until 2014, the front-end engineering design for Jack-Saint Malo has a provision for 200,000 barrels per day of water injection. The first Paleogene projects to come onstream recognize waterflooding as an improved oil recovery process.

10.4.5 Intervention Losses

Reservoir deliverability over the producing life of the development project is subject to losses arising from workovers, recompletions, plant upsets, reservoir treatments, retro-fitting, and other remedial work which forces wells to be shut in for an extended period of time. Interrupting the momentum of field operations can be damaging to ultimate recovery in that some production originally forecasted can no longer be recovered.

10.5 *Expectation of IOR Benefits*

Ultimate oil volumes by primary recovery methods are estimated at 10% of OOIP. Access to incremental reserves above the 10% primary volume calls for modifications to the base extraction method in the way of production optimization, pressure maintenance, remedies to problematic operations, and other techniques aimed at improving recovery. Extended-reach well completions, water and gas injection, artificial lift, open-hole gravel packing, water diversion systems, and hydraulic fracture stimulation are among the technology-focused solutions for raising the deliverability of Paleogene plays.

Reaching commerciality will be a formidable accomplishment since capital outlays for deepwater projects are some of the largest spends on industry record. The Perdido SPAR, subsea equipment, and wells are estimated to cost 3 billion USD (Reuters, March 2010). A standard deepwater well commands an investment of 100 million USD or more, putting restraints on the number of wells that can be affordably drilled. Monetary restrictions on drilling initiatives should be weighed against the value of field delineation, accelerated drainage from more take-points, and higher formation sweep efficiency. Another major cost center is ancillary

components such as tie-backs, pipeline infrastructure to shore, or other product handling facilities. Unit cost for oil and gas transportation pipelines is 4 million USD per mile of pipe installed in waters greater than 2,900 feet (MMS, 2007).

A typical Paleogene development venture has an estimated expenditure burden of at least 8 billion USD in capital costs over a 25-year life cycle (Ellis, 2010). For a stand-alone field concept comprised of a SPAR, 35 wells and 175 miles of export pipelines, the cost structure is modeled in Table 43. Deepwater economics based on these generic design elements are far from attractive. Assuming a primary recoverable of 180 million barrels (10% of average OOIP for a Paleogene field) and a sanctioned $60 per barrel oil price, forecasted gross revenue is only 10.8 billion USD whereas total capital and operating expenses over the lifespan exceed 18 billion USD. The project, at its worst, cannot cover all development costs nor satisfy government take. Mandatory taxes and royalties, not accounted for in the cost structure, worsen an already bleak economic picture. A shortfall of nearly 8 billion USD and a failure to minimally break even under this first-cut test for economic viability highlights deficient returns from un-optimized primary exploitation.

Profitability exists in the improved oil recovery value chain where extra earnings are generated by incremental production from depletion methods enhanced by IOR strategies. Operatorship venues to capture upside potential from unitization, infrastructure sharing, strategic business alliances, and regional synergies can further reduce exposure thus preserving IOR benefits.

Table 43: Typical Paleogene development cost structure

TYPICAL PALEOGENE DEVELOPMENT COST STRUCTURE (FORECAST ONLY)				
Project Life -	25 years			
CAPITAL EXPENDITURES				
Cost Center	Count	Unit Cost (millions USD)		Total Cost (millions USD)
Spar	1	4,000		4,000
Wells	35	100		3,500
Pipeline (miles)	175	4		700
			Total	8,200
OPERATING EXPENDITURES				
Percentage of CAPEX per year	5.0%			10,250
			Total	10,250
Total Project Expenditure, billions USD (real terms 2010)				**18.5**

10.5.1 Deriving Value from IOR Methods

Coaxing additional oil from reservoirs through improved oil recovery technologies and operational enhancements has garnered the attention of producers and researchers alike for over seventy years. From a long history of investigation and practice, the engineering science encompassing IOR procedure has evolved into a widely-recognized discipline founded on standard recovery schemes proven many times over by field-scale applications.

The quest for specialized, innovative procedures aimed at oil that is becoming more difficult to access demands novel techniques, some remarkably simple in their deployment while others have a complexity that defies the formulation of mechanistic, pore-scale models. Regardless of the IOR process under consideration, the objectives remain constant from method to method: (1) efficient extraction of oil beyond that recoverable from a base primary development plan and, (2) minimization of unrecovered hydrocarbon volume at final abandonment. Application of improved oil recovery techniques to offshore Paleogene oil fields mirrors these fundamental goals and perhaps more so given a critical dependence on IOR to mobilize some of the 90% original-oil-in-place left behind after primary efforts are concluded.

Reliance on improved oil recovery accentuates the importance of designing optimal depletion processes for deepwater field exploitation. Paleogene reservoirs are particularly amenable to potential IOR schemes because of a massive resource base, large volume of oil remaining at the end of unassisted primary depletion, and exceptionally high cost of abandonment. The term unassisted refers to a primary development project without elaborate well control and optimizing strategies such as horizontal or multilateral well technology, pressure maintenance, artificial lift, infill drilling, and hydraulic fracture stimulation to bolster a reservoir's natural drive energy. It is the most rudimentary of pressure drawdown operations. Improved oil recovery, by this admission, is any process that realizes oil production and recovery incremental to this baseline performance.

Many Paleogene fields have not progressed past the appraisal stage and are appropriate candidates for a greenfield IOR mandate. Planning of improved oil recovery methods in the overall field development concept increases the likelihood of full-cycle economic viability since costly retro-fitting programs can be mitigated when IOR contingencies are already accounted for in a flexible project design. Ideally, an IOR technique should be phased in at the onset but certainly before any anticipated high water production.

Early implementation of an engineered strategy has the potential benefit of a more effective oil displacement process that can extend the plateau oil rate thereby deferring the eventual arrival of field decline. A longer plateau period generally translates to an increase in total incremental oil recovered. Shifting the time of abandonment in combination with higher displacement efficiency, extra produced oil, and infrastructure cost savings would have a positive impact on a Paleogene project's net present value (Aikman et al., 1999). Decline behavior can also be moderated depending on the strategic imperatives factored into the original design. Recognizing the need for improved oil recovery at an early stage in the field development schedule underscores an incentive for real gains in profitability first by reducing capital exposure then raising technical recovery efficiency.

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10.6 *Improved Recovery Concepts*

10.6.1 IOR Processes for Paleogene Reservoirs

As shown in Figure 51, most improved oil recovery methods fall into three standard categories: thermal, non-thermal, and production technology supporting the base reservoir development. Since thermal exploitation is best suited for 10 to 20 °API heavy oils and tar sands with gravities less than 11 °API (Thomas, 2007), such methods are inappropriate for light Paleogene oil.

Non-thermal recovery technologies are suitable for light crudes with gravities of more than 25° API and viscosities less than 100 cP. Depending on structural geology, lithofacies and mineralogy, Paleogene fields are good candidates for water drives, miscible floods, and immiscible displacement. Though chemical floods have been widely tested, overall the field application results have been poor. Less proven processes and processes with more reservoir risk, such as MEOR and foam have not demonstrated a broad scope of application and are too risky for consideration.

Most Paleogene fields have not seen first oil and little production experience is available for judging IOR viability. The immediate strategy is to augment reservoir energy, raise sweep efficiency, and unlock capillary-bound oil in the primary depletion stage. Figure 74 is a short-list

of IOR methods selected as applicable for the Paleogene. The reservoir-based IOR processes selected for further screening are:

- Conventional water injection
- Seafloor water injection
- Low salinity water injection
- Conventional hydrocarbon gas injection
- Nitrogen gas injection

Many onshore CO2 projects have been field-verified throughout the world; however, the logistics of transporting a guaranteed source of carbon dioxide to a remote area of the Gulf is a major obstacle holding back IOR feasibility. Due to the cost burden of a dedicated supply of CO2, either by 150 miles or more of pipeline from the Texas coast or from a batch delivery via tanker, plus carbonic acid corrosion control, CO2 injection is eliminated from the options list.

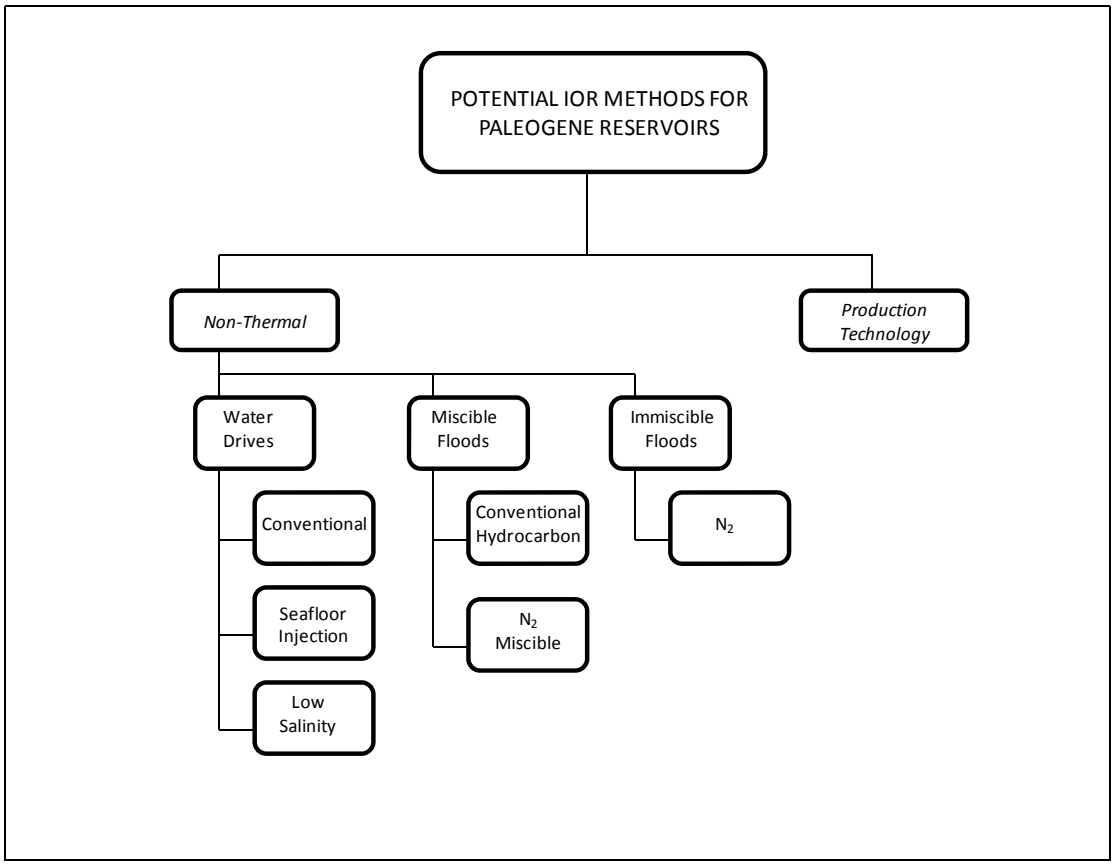

Figure 74: Potential IOR methods for Paleogene reservoirs

10.7 *Potential Recovery from Paleogene IOR Processes*

10.7.1 Technical IOR Recovery Factors

Reservoir performance under IOR processes deemed suitable for Paleogene exploitation is expected to reasonably follow the Neogene recovery ratings to some degree but with modifications to account for situations unique to Paleogene field development. Direct

assignment of Neogene recovery factors to Paleogene reservoirs is in keeping with general production experience in the Gulf, similar IOR trials at shared field analogs, and commonality in deepwater field operations. Low salinity water injection (3-7%) and nitrogen flooding (3-12%) in Paleogene fields are assumed to yield the same proportional recovery as their Neogene counterparts.

A low-to-high technical IOR recovery factor range of 2-22% is forecast for conventional water injection (Lui et al., 2008). The waterflood IOR estimated by the sector model of Paleogene reservoir is 6% (Appendix A) as the reference for technical IOR recovery factor determination. Seafloor water injection would produce incremental oil comparable to the conventional method but performance is downgraded for subsea operating difficulties and additional interventions. The range, adjusted on the high side, becomes 2-15%.

Conventional hydrocarbon gas injection has a range of 3-8%, correcting the Neogene high-end factor downward to reflect the deep, high pressure-high temperature, low permeability conditions in Paleogene plays.

Turning to IOR processes tied to production technology, the benefit of diverting agents is set at 3-7.5% or about half of the oil trapped by inefficient sweep (15%).

An in-well ESP has an advantage over subsea multi-phase pumping provided the equipment is re-tooled for the Paleogene subsurface environment. The IORs of in-well ESP and multi-phase pumping at mudline estimated by the sector model of Paleogene reservoir are 5% and 6% respectively (Appendix A). Based on the results, the performance assumptions are 5-10% for subsea multi-phase pumping and 3-15% for the in-well ESP.

Under well technology, highly deviated (horizontal) wells and their variations have an expectation of 2-5% incremental oil recovery, the high side reduced slightly from the Neogene figure to measure complexities related to deeper wells in highly-stratified formations.

Hydraulic fracture stimulation has both high technical and economic merit as a technology-focused remedy for tight Paleogene rock. A boost of 5-10% additional oil is tied to emplacement of induced fracture systems. In the Walker Ridge area, a frac-pack procedure was successfully applied to a high pressure-high temperature Jack well drilled to 27,000 feet. However, hydraulic fracture treatments similar to those used onshore for tight reservoirs can possibly be adapted to the Paleogene reservoirs.

Technical IOR recovery factors for the suite of Paleogene IOR processes are given in Table 44.

Table 44: Technical incremental oil RF ranges for Paleogene IOR processes

Technical IOR Recovery Factor for Paleogene Fields				
Process Number	IOR Category	IOR Process	Technical IOR Recovery Factor	
			Low	High
1	WATER INJECTION	Conventional Water Injection	2.0%	22.0%
2		Seafloor Water Injection	2.0%	15.0%
3	WATER-BASED EOR	Low Salinity Water Injection	3.0%	7.0%
4	GAS INJECTION	Conventional Hydrocarbon Gas Injection	3.0%	8.0%
5	GAS-BASED EOR	Nitrogen Injection	3.0%	12.0%
6	DIVERTING AGENTS	MEOR Water Injection Diverters	3.0%	7.5%
7	PUMPING and ARTIFICIAL LIFT	Subsea Multi-phase Pumping	5.0%	10.0%
8		In-well ESP	3.0%	15.0%
9	WELL TECHNOLOGY	Hydraulic Fracturing	5.0%	10.0%
10		Deviated / Horizontal Wells	2.0%	5.0%

10.7.2 Implication of Economic Reality

The exceptionally high cost of doing business in the deepwater frontiers of the Gulf made clear by 100 million USD minimum capital outlay for drilling a single Paleogene well puts into perspective the serious economic challenges that must be addressed even with optimistic technical feasibility. Technical merit alone cannot sanction project development. Indeed, economic rationalization is a final step in validating a development concept proposal.

Aside from the provision of a Paleogene cost structure estimate, this evaluation is limited to establishing the relative merit of certain IOR processes on a technical basis. A quantitative investigation of economic viability is outside the scope of study.

10.7.3 Risk Appraisal for Incremental Reserves

A simple approach was taken to incorporate the element of risk into the evaluation methodology. For each IOR process of interest, incremental oil volume as a fraction of original-oil-place was determined for three risked scenarios corresponding to P90, P50, and P10 cases. Risk-adjusted potential barrels are based on the following convention:

- P90 IOR R.F. = low technical IOR recovery factor
- P10 IOR R.F. = high technical IOR recovery factor
- P50 IOR R.F. = (P90 IOR R.F. + P10 IOR R.F.) / 2

Therefore,

- P90 risked incremental oil volume = P90 IOR R.F. x P50 OOIP
- P10 risked incremental oil volume = P10 IOR R.F. x P50 OOIP, and

P50 risked incremental oil volume = P50 IOR R.F. x P50 OOIP.

10.7.4 Technical Readiness Level (TRL) of Paleogene IOR Processes

As in the Neogene evaluation, technical readiness levels for Paleogene IOR methods are assigned according to the adapted DeepStar guidelines. The TRLs determined for Paleogene IOR processes are generally equivalent or lower maturity for the same Neogene method. A lower rating signifies greater uncertainty and lack of fit-for-purpose infrastructure for stepping out into deeper, harsher conditions in Paleogene reservoirs. For example, significant practice with horizontal wells in Neogene fields and very little experience in Paleogene horizons results in a Neogene rating of 6 while only 5 is assigned to the Paleogene case.

A summary of the technical readiness levels of potential Paleogene IOR processes is given in Table 45.

Table 45: Technical readiness factors, Paleogene IOR processes

Technical Readiness Levels of Potential IOR Processes			
Process Number	**IOR Category**	**IOR Process**	**Technical Readiness Level (TRL 0-7)**
1	WATER INJECTION	Conventional Water Injection	6
2		Seafloor Water Injection	4
3	WATER-BASED EOR	Low Salinity Water Injection	2
4	GAS INJECTION	Conventional Hydrocarbon Gas Injection	5
5	GAS-BASED EOR	Nitrogen Injection	4
6	DIVERTING AGENTS	MEOR Water Injection Diverters	1
7	PUMPING and ARTIFICIAL LIFT	Subsea Multi-phase Pumping	6
8		In-well ESP	5
9	WELL TECHNOLOGY	Hydraulic Fracturing	4
10		Deviated / Horizontal Wells	5

10.7.5 Enabling Technologies and Development Needs

Improvements from production technology are realized through mechanical, chemical, thermal, and kinetic means such as well design, stimulation, artificial lift, heat management, water shut-off, conformance control, solids management, sand contention, reservoir souring control, hydrate inhibition and the like. These measures are considered enhancements to a traditional reservoir-based method but are nonetheless IOR processes capable of raising ultimate recovery. Many of these tools and procedures are essential to primary depletion and are thus enabling technologies built into the initial field conceptualization. Other techniques are aimed at breaking down the impediments to offshore field development.

Operating technologies critical to Paleogene exploitation are pumping and artificial lift, extended reach (horizontal) well technology, hydraulic fracturing, and water injection diverters. Depending on the nature of the reservoir and its specific behavior, additional remedies may be called for:

- Multi-azimuth and wide-azimuth seismic surveys for sub-salt illumination
- Heat management by electrical heating and heat tracing
- Addition of a light diluents (naptha) to manage viscosity of flowing oil
- Frac and pack completions
- Stimulation fracture height control to avoid contacting water or depleted zones
- Acid treatment to remove near-wellbore damage
- Plugs, packers, liners, and cement squeeze for mechanical water shut-off
- Smart chemical diversion systems for selective, temporary plugging of high water zones
- Injectivity modification with a viscosifier polymer
- Hot water injection to reverse wax deposition
- Operating above the asphaltene onset pressure (AOP)
- Methanol or glycol to inhibit hydrate formation
- Prevention of scale by filtration of suspended solids
- Reservoir souring contention

Even with this vast toolkit of enabling technologies, there are fundamental deficiencies in IOR concepts that need to be solved both in theory and practice. Major technical gaps holding back Paleogene development are:

- Timely and reliable sub-salt seismic visualization
- A weak mechanistic model for low-salinity water injection
- Lack of a comprehensive model to better understand nitrogen flooding
- Offshore desalination plants dedicated to oil operations
- Cryogenic facilities operating on offshore platforms.
- Technology transfer is a critical driver in project realization.

10.8 *Paleogene IOR Process Evaluation*

10.8.1 Target OOIP from Field Applications

Five reservoir technologies and an equal number of production enhancements to the base IOR process were evaluated on a stand-alone basis. This is to say that ten different IOR processes were analyzed independently of one another rather than in various integrated strategies as would typically be the case for recovery optimization. A realistic hybrid solution is a combined waterflood and gas injection project utilizing premium in-well ESP. Unified IOR processes capture depletion and operating synergies but in order to identify possible overlaps in targeting the same trapped oil volume, more granularities are needed to describe each reservoir.

Without adequate details for dynamic reservoir modeling, the evaluation results may overstate the aggregate incremental volume forecasted. The target OOIP in each of the ten independent appraisals assumes a given IOR process can be applied equally well to all fourteen fields in the Paleogene resource base.

10.8.2 Ranking Metric for Prioritizing IOR Processes

Potential IOR processes are screened on a P50-risked incremental oil volume which has been normalized by the technical readiness level (TRL). The formula for this ranking metric is:

P50-Risked IOR Volume = P50 case potential volume

x (process TRL / maximum TRL of 7)

Individual IOR processes are then compared by rank ordering the TRL-adjusted potential volumes in descending order.

10.8.3 IOR Process Ranking for Paleogene Fields

Input assumptions for IOR processes under consideration and evaluation outcomes are detailed in Table 46. The top-ranking Paleogene IOR processes are conventional water injection, subsea multi-phase pumping, and in-well ESP.

Table 46: Paleogene IOR process evaluation and ranking

DEEPWATER GULF OF MEXICO: IOR PROCESS RANKING FOR PALEOGENE FIELDS													
				Technical IOR Recovery Factor		Applications		Target Potential Barrels					
Process Number	IOR Category	IOR Process	Trapped Oil Mechanism Target	Low	High	Field Count	Target OOIP for Field Count (MMstb)	P90 (MMstb)	P50 (MMstb)	P10 (MMstb)	Technical Readiness Level (TRL 0-7)	P50 Risked IOR (MMstb)	IOR Process Ranking
1	WATER INJECTION	Conventional Water Injection	displacement drive energy	2.0%	22.0%	14	25,000	500	3,000	5,500	6	2,571	1
2		Seafloor Water Injection	displacement drive energy	2.0%	15.0%	14	25,000	500	2,125	3,750	4	1,214	4
3	WATER-BASED EOR	Low Salinity Water Injection	capillary bound	3.0%	7.0%	14	25,000	750	1,250	1,750	2	357	9
4	GAS INJECTION	Conventional Hydrocarbon Gas Injection	sweep efficiency	3.0%	8.0%	14	25,000	750	1,375	2,000	5	982	7
5	GAS-BASED EOR	Nitrogen Injection	capillary bound	3.0%	12.0%	14	25,000	750	1,875	3,000	4	1,071	6
6	DIVERTING AGENTS	MEOR Water Injection Diverters	sweep efficiency	3.0%	7.5%	14	25,000	750	1,313	1,875	1	188	10
7	PUMPING and ARTIFICIAL LIFT	Subsea Multi-phase Pumping	high abandonment pressure	5.0%	10.0%	14	25,000	1,250	1,875	2,500	6	1,607	2
8		In-well ESP	high abandonment pressure	3.0%	15.0%	14	25,000	750	2,250	3,750	5	1,607	3
9	WELL TECHNOLOGY	Hydraulic Fracturing	non-connected volume and sweep efficiency	5.0%	10.0%	14	25,000	1,250	1,875	2,500	4	1,071	5
10		Deviated/ Horizontal Wells	non-connected volume and sweep efficiency	2.0%	5.0%	14	25,000	500	875	1,250	5	625	8

10.8.4 Summary of Key Paleogene IOR Concepts

With a long history of offshore experience, conventional water injection has the highest expectation for success in all Paleogene reservoirs. Seafloor water injection is the next best recovery technology followed by nitrogen flooding then conventional hydrocarbon gas injection. Low salinity water injection, still in its infancy, has the lowest rating of the reservoir-based IOR processes.

Some form of subsea boosting either by multi-phase pumping or submersible pumps is clearly a solution for high abandonment pressures. The technologies can each raise incremental recovery by 6 to 7%. A new generation of downhole ESP has a large upside potential for extending the producing life of a Paleogene reservoir.

Hydraulic fracturing, capable of tripling production rate, will prove to be an effective treatment for low permeability reservoirs.

The overall IOR benefit is phased over the Paleogene development schedule in step-wise increments correlated to various stages of depletion. Relative contributions from select IOR process are sequenced in the following development scenario:

- Primary = 10%
- Optimized Primary = hydraulic fracturing (4.3%), extended reach wells (2.5%)
- Secondary-IOR = conventional water injection (10.3%)
- Optimized Secondary = diverting agents (0.8%), pumping (6.4%), ESP (6.4%)
- Secondary-EOR = low-salinity injection in tertiary mode (1.4%)
- Other ranked processes are deemed outside this feasibility window

All fourteen fields are considered stand-alone operations without the benefit of unitization or strategic alliances. Impact of field size is ignored and all fields are developed with the same methods and phasing. Inter-relationships across different IOR processes are not accounted for.

The inverted waterfall chart in Figure 75 represents an aggregate deliverability forecast for Paleogene exploitation. The target oil EUR is 42.1% recovery of OOIP.

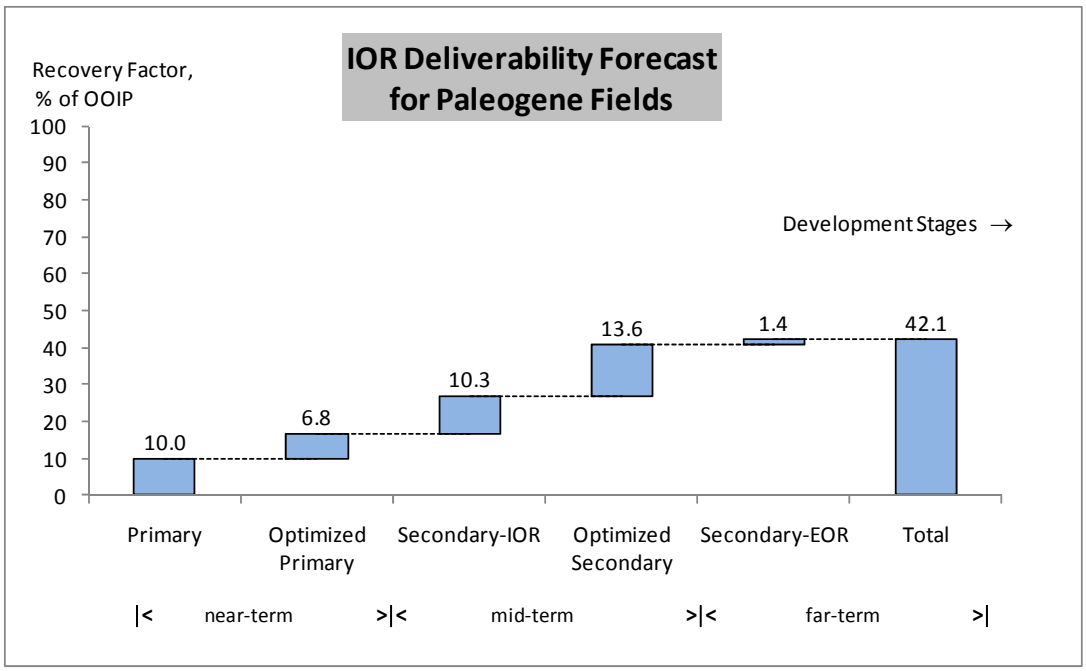

Figure 75: Paleogene IOR deliverability sequence and total potential

11 Conclusions

The following are conclusions on the potential for improved recovery in deepwater Gulf of Mexico fields.

1. For IOR considerations, the deepwater Gulf of Mexico fields and reservoirs are divided into two age groups due to significant property and drive energy differences:
   - Neogene: Miocene, Pliocene, and Pleistocene age reservoirs
   - Paleogene: Oligocene, Eocene, Paleocene
2. Oil recovery in Neogene reservoirs ranges from 16% - 32% - 48% (P90-P50-P10). These statistics exclude reservoirs with water injection. However, when waterflooded reservoirs are included, the statistics are unchanged due to limited historical water injection.
3. There is a large target for improved recovery in the Neogene because:
   - Average oil recovery is modest at 32% and the projected ROIP in discovered fields is 21 billion bbl.
   - Many reservoirs have only moderate natural drive energy from rock compaction and aquifer influx.
   - Only a limited number of reservoirs have high recovery >50% from strong aquifer drive or engineered waterflooding.
4. The primary risks of implementing IOR projects in Neogene reservoirs are:
   - Average reservoir OOIP is small at ~ 50 MMSTB which combined with the high costs of deepwater operations creates challenging economics.
   - Reservoirs are deep and geologically complex (structural and depositional), and the seismic image is typically of low resolution. This has led to a poor track record of predicting performance and has elevated the risk profile for all incremental projects.
   - The high cost of wells.
5. The most promising IOR concepts for Neogene are:
   - Adding reservoir energy by injecting water or gas. Water injection is most favorable due to the robust gas sales infrastructure.
   - There is a need for a low-cost alternative for water injection. The most favorable alternatives are seafloor water injection and aquifer dump flooding.
   - Subsea boosting and artificial lift are key IOR technologies for primary production optimization and enhancing secondary recovery permitting flow to higher water cut.
   - Nitrogen is a good alternative for adding reservoir energy and with tertiary recovery benefits since it would be miscible in many reservoirs. There are many operational benefits for using inert nitrogen gas. The potential drawback is that asphaltenes can be more unstable in the presence of the gas.
   - Injection of low-salinity water is an emerging technology which can add tertiary recovery benefits to a waterflood by reducing residual oil saturation (Sor). Nano-filtration membrane technology has advanced rapidly for offshore sulfate reduction plants, and is quickly becoming an industry standard for waterflood projects (deepwater Angola and Ursa and Shenzi in the GoM). A low salinity injection project would use similar hardware and is therefore near technical readiness. There is still uncertainty in understanding the reservoir recovery

mechanisms and the application of the IOR process has not been proven through full field use. However, there are huge benefits in the deepwater Gulf of Mexico for the implementation of a low salinity water injection system at the same time that water injection equipment is added for secondary recovery.
- There is a significant need for low-cost riserless light well intervention (RLWI) technology due to the number and growth rate of wet tree installations.

6. The Paleogene age reservoirs in Keathley Canyon and Walker Ridge have significant oil recovery challenges. The forecast primary RF is only 10% of OOIP, and the expected ROIP in discovered fields is 23 Billion Bbl. There is no production experience, and no suitable analog was found worldwide. The development risk is high due to stepping out into a new frontier of depth, high pressure / high temperature, and complex geology
7. The Paleogene requires critical new technology for even primary production and development. Key IOR concepts for improving oil recovery are:
   - Adding reservoir energy through water injection
   - Technology for reservoir management of water injection and production from a thick, heterogeneous reservoir. This includes downhole data acquisition (pressure, rate, water cut) and control equipment for multi-zone completions with remote operation or control by RLWI vessel.
   - Subsea pumping and downhole pumps with high operating delta pressure to achieve lower BHFP and abandonment pressure.
   - Seafloor water injection is needed for remote, ultra-deepwater fields which are a long distance from the host facility
   - Advancements in hydraulic fracturing to enhance productivity and injectivity in a low permeability reservoir

12 Technical Gaps

Of the nineteen prime reservoir and production based IOR processes deemed suitable for Neogene reservoirs, only two concepts are considered proven technology in the deepwater Gulf of Mexico. Both conventional water injection and subsea multi-phase pumping have attained the highest technical readiness level (TRL) of 7. Ten potential improved oil recovery methods were evaluated and ranked for the Paleogene study area. Again, conventional water injection and subsea multi-phase pumping are the most advanced technologies, however, a TRL of 6 was assigned to each to reflect limited experience with the deeper Paleogene reservoirs and their unusual high pressure-high temperature conditions.

For the most part, both Neogene and Paleogene IOR technologies are immature. Technical gaps now prevent their implementation in the deepwater Gulf though progress is being made on proving IOR mechanisms, perfecting production technologies that enable the underlying depletion strategy, building onto the experience base, and leveraging operating synergies and business alliances to lower project costs. Table 47 and Table 48 outline the present status of potential IOR methods applicable to Paleogene and Neogene reservoirs, respectively. Current technical readiness levels are stated for each IOR process under review. Bridging solutions presented here are steps necessary for bringing still-to-be matured IOR concepts into the realm of deepwater field-proven technology.

Table 47: Technical gaps in Paleogene IOR processes

Technical Gaps in Paleogene IOR Processes				
Process Number	**IOR Category**	**IOR Process**	**Current TRL (0 – 7)**	**Bridging Solutions to Reach Proven Technology (TRL 7)**
1	Water injection	Conventional water injection	6	▪ Validate technology at the field-scale in deep (>25,000 ft TVD), high pressure (>20,000 psi), and high temperature (>250 °F) reservoir conditions ▪ A key Paleogene-specific need is reservoir management of water injection and production from thick, heterogeneous formations supported by downhole data acquisition and control equipment for multi-zone completions operated remotely with a riserless light well intervention (RLWI) vessel
2	Water injection	Seafloor water injection	4	▪ Validate technology at the field-scale in deep (>25,000 ft TVD), high pressure (>20,000 psi), and high temperature (>250 °F) reservoir conditions ▪ Capture North Sea experience on the evaluation, design and performance of seafloor water injection ▪ Transfer viable subsea water injection and treatment (SWIT) concepts deployed at Ekofisk, Tordis and Columba (North Sea), Tyrihans (Norwegian CS), Marlim and Albacora (Campos), Barton (Malaysia) to the deepwater environment ▪ For better reliability and performance, optimize smart SWIT system for automation, and remote operation ▪ Adapt existing solids removal, continuous water sterilization, and biocide dosing equipment for deepwater applications ▪ Create best-in-class software tools which can confidently model reservoir souring, corrosion, plugging, and scaling associated with seawater injection. The tools need to reduce the risk of these operational issues by helping to formulate the mitigation plan which prevents souring, corrosion, and scaling.
3	Water-based EOR	Low salinity water injection	2	▪ Adopt a comprehensive pore-scale model that adequately explains the displacement mechanisms behind the low salinity effect in deepwater Gulf of Mexico reservoirs ▪ Adapt and enhance the current sulfate removal nano-filtration technology for desalinization to <5000 ppm in a facility footprint for offshore platform use.

				▪ Identify reservoir/operating risks (rock mineralogy, swelling clays, initial wettability, formation water ionic profile, cation exchangers etc.) ▪ Once mechanisms for improved recovery are understood, provide enhancements to predictive tools for history matching successful injection projects and forecasting reservoir performance under low salinity injection
4	Gas injection	Conventional hydrocarbon gas injection	5	▪ Transfer injection technologies successfully demonstrated in North Sea and onshore Alaska (North Slope) projects to deeper, high pressure-high temperature conditions in the Gulf ▪ Modify well completions to ensure integrity when operating at high injection pressure in high pressure-high temperature environments ▪ Given the likelihood that produced gas from low-GOR Paleogene oil cannot satisfy utilization rates, an external gas source is required (e.g. stranded nearby gas pools) ▪ Identify the asphaltene onset pressure (AOP) at various reservoir conditions and derive nomogram-type charts for managing in-situ deposition ▪ Expand compressor operating range to deliver the injectant to deep, tight, and possibly overpressured zones ▪ Factor in the option of an offshore C3-C5 extraction facility for recycling produced gas
5	Gas-based EOR	Nitrogen injection	4	▪ Adapt nitrogen injection technology used for shallower, onshore projects for deeper, high pressure-high temperature conditions ▪ Better understand the reduction of residual oil saturation by nitrogen miscibility ▪ Re-tool proven onshore cryogenic facilities as small, light-weight offshore units for extracting nitrogen from air ▪ If necessary, modify the well completion to ensure integrity when operating at high injection pressure in high pressure-high temperature environments ▪ Expand compressor operating range to deliver the injectant to deep, tight, and possibly overpressured zones ▪ Identify the asphaltene onset pressure (AOP) at various reservoir conditions and derive nomogram-type charts for managing in-situ deposition ▪ Find an accurate correlation which gives the minimum miscibility pressure (MMP) of nitrogen with crude oils ▪ Augment the offshore cryogenic-injection system with a nitrogen rejection facility to separate N2 from the gas production stream for recycling ▪ Develop chemical to inhibit the increase of the AOP with the introduction of nitrogen to oil
6	Diverting agents	MEOR water injection diverters	1	▪ Advance a dynamic method of conformance management using microbes coupled with water injection as an alternative to traditional mechanical control of multiple zone injection ▪ Adapt current technology for higher GoM temperatures (>180 °F) and larger offshore well spacing ▪ Identify the inter-relationships of key chemical and biological drivers in an engineered MEOR application (strain, nutrient concentration, reservoir chemistry, in-situ temperature etc.) ▪ Establish the link between microbial treatment and lowering of residual oil saturation ▪ Investigate microbial visbreaking of low API crude oil ▪ Design a hybrid waterflood optimization process whereby microbes are routinely used in water injection to add tertiary benefits during the secondary recovery process ▪ Quantify observed recovery improvement in terms of microbial design parameters ▪ Develop a new specialized simulation tool for predicting in-situ MEOR performance
7	Pumping and artificial lift	Subsea multi-phase pumping	6	▪ Extend offshore field applications to deeper, high pressure-high temperature conditions ▪ Minimize down-time using riserless light well intervention (RLWI)
8	Pumping and	In-well ESP	5	▪ Tailor current downhole pump technology for delivering higher rates and lowering abandonment pressure

	artificial lift			▪ Incorporate changes for better reliability in extremely deep, high pressure-high temperature operating environments ▪ Evaluate new approaches in the way of hydraulic submersible pumps or an ESP with rigless access
9	Well technology	Hydraulic fracturing	4	▪ Transfer fracture stimulation technology employed in onshore tight gas reservoirs to offshore targets with the goal of delivering a two- to three-fold gain in oil recovery from low permeability rock ▪ Design custom frac fluid rheology needed for long service time in high temperatures (>250 °F) ▪ Ensure adequacy of proppant strength under excessive overburden pressures
10		Deviated / horizontal wells	5	▪ Consider the technical feasibility and merit of drilling horizontal wells in high pressure environments ▪ Determine whether well geometry is a solution to the productivity issue ▪ Overcome the difficulties from using a slant or multi-lateral well to contact stacked reservoirs in very thick, highly-stratified formations ▪ Transfer techniques used for long horizontal and multi-lateral wells in the deepwater Campos Basin to the deepwater GoM ▪ To achieve HSE standards, adopt best practices for overbalanced drilling

Table 48: Bridging solutions for technical gaps in Neogene IOR processes

Bridging Solutions for Technical Gaps in Neogene IOR Processes				
Process Number	**IOR Category**	**IOR Process**	**Current TRL (0 – 7)**	**Bridging Solutions to Reach Proven Technology (TRL 7)**
1	Water injection	Conventional water injection	7	▪ Status is proven technology for Neogene oil plays in the deepwater Gulf of Mexico ▪ Process can be further optimized with: – A lower-cost, smaller-footprint platform alternative for mature fields with existing infrastructure – Reliable completion design and remediation of existing wells for multiple-zone completions in partially depleted reservoirs – Enabling technologies of enhanced reservoir characterization (wide azimuth seismic imaging for high quality deep/sub-salt illumination), and lower well costs (strategic drilling alliances, producer-held rig operatorship)
2	Water injection	Seafloor water injection	4	▪ Validate technology at the field-scale in Neogene reservoir (depth: 10,000-20,000 ft TVD; pressure 10,000-13,000 psi; temperature: 180-200 °F) ▪ Capture learnings from the North Sea experience on the evaluation, design and performance of seafloor water injection ▪ Transfer viable subsea water injection and treatment (SWIT) concepts deployed at Ekofisk, Tordis and Columba (North Sea), Tyrihans (Norwegian CS), Marlim and Albacora (Campos), Barton (Malaysia) to the deepwater environment ▪ For better reliability and performance, optimize smart SWIT system for automation and remote operation ▪ Adapt existing solids removal, continuous water sterilization, and biocide dosing equipment for deepwater applications ▪ Create best-in-class software tools which can confidently model reservoir souring, corrosion, plugging, and scaling associated with seawater injection. The tools need to reduce the risk of these operational issues by helping to formulate the mitigation plan which prevents souring, corrosion, and scaling.
3	Water Injection	Aquifer dump flooding water injection	4	▪ Transfer production experience from October Field (offshore Egypt, uncontrolled), Zakum Field (offshore Abu Dhabi, uncontrolled), Umm Gudair Field (Kuwait, uncontrolled), Onbysk Field (Russia, reverse controlled), to decide on success factors in the deepwater ▪ Concept approval from GoM deepwater regulatory body for

				deployment of this technology in water injection schemes ▪ Set regulated guidelines by which operators will need to prove an aquifer is a viable source and that the completion design will adequately manage the waterflood ▪ Map known natural aquifers contacted by deepwater GoM wells that are prolific, have high pressure plus good deliverability, and are preferably upstructure of candidate reservoirs for waterflooding ▪ Improve reliability and performance of intelligent completions (e.g. dual water supply from aquifer and target reservoir injection; dual action pumping systems for separation of oil from water in controlled dumpflooding) ▪ Develop advanced downhole data acquisition technology for monitoring crossflow rate and wellbore injection pressure in uncontrolled methods, control of injection rate, and prevention of solids plugging ▪ Devise a metering system for tracking individual component streams commingled from simultaneous production and injection in stacked reservoir plays ▪ Integrate tests for purity of injected water into smart well dumpflood design ▪ Control injection profile through re-completion of multi-tasking wells
4	Water-based EOR	Low Salinity Water Injection	2	▪ Adopt a comprehensive pore-scale model that adequately explains the displacement mechanisms behind the low salinity effect in deepwater Gulf of Mexico reservoirs ▪ Adapt and enhance the current sulfate removal nano-filtration technology for desalinization to <5000 ppm in a facility footprint for offshore platform use. ▪ Identify reservoir/operating risks (rock mineralogy, swelling clays, initial wettability, formation water ionic profile, cation exchangers etc.) ▪ Once mechanisms for improved recovery are understood, provide enhancements to predictive tools for history matching successful injection projects and forecasting reservoir performance under low salinity injection
5	Water-based EOR	Microbial EOR	3	▪ Advance a dynamic method of conformance management using microbes coupled with water injection as an alternative to traditional mechanical control of multiple zone injection ▪ Adapt current technology for higher GoM temperatures (>180 °F) and larger offshore well spacing ▪ Identify the inter-relationships of key chemical and biological drivers in an engineered MEOR application (strain, nutrient concentration, reservoir chemistry, in-situ temperature etc.) establish the link between microbial treatment and lowering of residual oil saturation ▪ Investigate microbial visbreaking of low API crude oil ▪ Quantify observed recovery improvement in terms of microbial design parameters ▪ Develop a new specialized simulation tool for predicting in-situ MEOR performance
6	Water-based EOR	Alkaline surfactant polymer (ASP)	3	▪ From lab analyses, determine the suitability of tertiary ASP to medium-gravity GoM crudes in a low viscosity, low dosage method for existing waterflooded fields ▪ Qualify deepwater GoM reservoirs by mineralogy, de-selecting ASP candidates with a large clay fraction that would impede the IFT-reducing capacity of an added chemical ▪ Reduce the injected pore volume for a given IOR benefit by improving the efficiency of ASP reactions ▪ Dedicate research to smart chemical additives such as demulsifiers, petroleum soaps, and viscosifiers including methods for mitigating chemical consumption/degradation ▪ Investigate ways to increase the longevity of ASP chemicals particularly polymers subjected to high temperature ▪ As a cost saving measure, assess processes for extracting produced chemicals for recycling
7	Water-based	Chemical augmented	2	▪ Due to significant technical gaps in offshore application, postpone evaluating technical merit until after IOR screening for low salinity, MEOR, ASP, and gas-based EOR

	EOR	waterflooding		
8	Gas injection	Conventional hydrocarbon gas injection	5	▪ Transfer injection technologies successfully demonstrated in North Sea and onshore Alaska (North Slope) projects to deeper, high pressure-high temperature conditions in the Gulf ▪ If necessary, modify the well completion to ensure integrity when operating at high injection pressure in high pressure formations ▪ Carry out industry study to reconcile stranded gas reserves and secondary gas reservoirs in oil fields for potential secondary recovery utility ▪ Identify the asphaltene onset pressure (AOP) at various reservoir conditions and derive nomogram-type charts for managing in-situ deposition ▪ Expand compressor operating range to deliver the injectant to deep, overpressured zones ▪ Factor in the option of an offshore C3-C5 extraction facility for recycling produced gas
9	Gas injection	Hydrocarbon gas dump flooding	0	▪ Obtain conceptual approval from the regulatory authorities to use technology for pressure maintenance and IOR ▪ Hydrocarbon gas source in reservoirs in the target field. ▪ Develop a robust well completion for dual gas production and re-injection in the same well with downhole control and rate measurement
10	Gas-based EOR	Nitrogen injection	4	▪ Adapt nitrogen injection technology used for shallower, onshore projects for deeper, high pressure-high temperature conditions ▪ Better understand the reduction of residual oil saturation by nitrogen miscibility ▪ Re-tool proven onshore cryogenic facilities as small, light-weight offshore units for extracting nitrogen from air ▪ If necessary, modify the well completion to ensure integrity when operating at high injection pressure in high pressure-high temperature environments ▪ Expand compressor operating range to deliver the injectant to deep, tight, and possibly overpressured zones ▪ Identify the asphaltene onset pressure (AOP) at various reservoir conditions and derive nomogram-type charts for managing in-situ deposition ▪ Find an accurate correlation which gives the minimum miscibility pressure (MMP) of nitrogen with crude oils ▪ Augment the offshore cryogenic-injection system with a nitrogen rejection facility to separate N2 from the gas production stream for recycling ▪ Develop chemical to inhibit the increase of the AOP with the introduction of nitrogen to oil
11	Gas-based EOR	CO2 Injection	3	▪ CO2 supply and deliver system to offshore installation(s). Operator's group study required to look at share infrastructure and supply hub. ▪ An industry CO2 supply initiative to collect and then distribute CO2 to offshore "core areas" for multiple field application ▪ Design and develop a light-weight and small footprint facility for CO2 separation from hydrocarbon gas for an offshore platform. ▪ A safety and cost-benefit analysis study of example deepwater offshore field for determination of CO2 economic challenges and future industry initiatives
12	Diverting agents	Foam and other chemicals	4	▪ Advance a dynamic method of conformance management using microbes coupled with water injection to replace traditional mechanical control of multiple zone injection ▪ Adapt current MEOR technology for higher GoM temperatures (>180 °F) and larger offshore well spacing ▪ Identify the inter-relationships of key chemical and biological drivers in an engineered MEOR application (strain, nutrient concentration, reservoir chemistry, in-situ temperature etc.) ▪ Establish the link between microbial treatment and lowering of residual oil saturation ▪ Investigate microbial visbreaking of low API crude oil ▪ Design a waterflood optimization process whereby microbes are routinely used in water injection to add tertiary benefits during the

				secondary recovery process ▪ Quantify observed recovery improvement in terms of microbial design parameters ▪ Develop a new specialized simulation tool for predicting in-situ MEOR performance
13	Pumping and artificial lift	Subsea multi-phase pumping	7	▪ Status is proven technology for Neogene oil plays in the deepwater Gulf of Mexico ▪ Process can be further optimized with: – A new multiphase pump development capable of handling a higher gas fraction to reduce pump inlet pressure and to ultimately lower abandonment pressure
14	Pumping and artificial lift	In-well ESP	6	▪ Tailor current downhole pump technology for delivering higher rates and lowering abandonment pressure ▪ Improve reliability of a deep-set pump installation for delivery of high head and at high operating pressures/temperatures ▪ Evaluate new approaches in the way of hydraulic submersible pumps or an ESP with rigless access ▪ Develop a reliable downhole power supply with wet tree connectors and for dry tree wells on floaters with vertical heave
15	Pumping and artificial lift	In-well gas lift	6	▪ Adapt proven technology used in both shallow and deepwater dry tree completions and, in riser/subsea manifold based equipment to downhole, wet tree installations in the deepwater GoM ▪ Generate high operating pressure gas-lift values
16	Pumping and artificial lift	Subsea processing	6	▪ Combine gas-liquid separation with high pressure liquid boosting where subsea tie-backs are more than 50 miles
17	Well technology	Low-cost wells	0	▪ Investigate new rig ownership and contracting strategy to reduce day-rate costs of deepwater rigs and to help stimulate deepwater drilling ▪ Form an industry study group to develop low cost, slim well design for IOR projects applying water or gas injection
18	Well technology	Low-cost well intervention	5	▪ Develop riserless intervention methods with lubricators for wet tree access and downhole minor remedial operations. ▪ Design a fit-for-purpose downhole aquifer dumpflood completion which can be replaced with light well intervention (LWI) vessels ▪ Implement data acquisition telemetry systems without electric cables for easier and lower cost interventions
19	Well technology	Horizontal / multi-lateral wells	6	▪ Improved reliability of horizontal well completions in overpressured reservoirs ▪ Need for highly deviated well completion strategy to improve performance in poorly connected, compartmentalized reservoir.
20	Other	Enabling technology	N/A	▪ Improve reservoir characterization to reduce the risks of project forecasts of IOR benefits ▪ Develop high-quality sub-salt reservoir imaging with enhancements to current seismic surveying and interpretation methods or by new reservoir imaging technology ▪ Establish reservoir sensing technology similar to dynamic testing that uses pressure impulses for determining reservoir connectivity

13 Recommendations

Recommendations for future work to attempt to bridge the technical gaps for IOR processes are summarized below.

1. The risked IOR project economics will be greatly improved with the key enabling technologies of better reservoir characterization and lower well costs as described below:
   - Fund research on improving wide azimuth seismic technology or finding alternative tools for imaging below salt and in deep reservoirs.
   - Develop new remote sensing technology that provides the equivalent of dynamic data without production or testing.
   - Fund research with operators and service providers to evaluate a “paradigm shift” in drilling technology and cost.
   - Fund research for the development of riserless light well intervention (RLWI) or rigless vessels for well intervention with fit-for-purpose design in consideration of future Paleogene completion needs.
2. Overcome the perceived risks for seafloor water injection and aquifer dump flooding in deepwater GoM.
   - Funding of a study to identify field applications and to develop a basis of design.
   - Review and capture knowledge base from North Sea studies (CAPSIS and C-FAST).
   - Improve where required the accuracy of predictive tools for souring, scaling, and corrosion.
3. Technology gaps for waterflooding the Paleogene are numerous. Fund research in conjunction with operators and service providers in defining and developing the following new equipment, techniques, and materials:
   - Completion technology to improve injectivity and provide control of injection profile.
   - Injector completion where integrity is not compromised with downhole cross-flow.
   - Reliable multi-zone completion for producers with data acquisition (pressure, rate, water cut), mechanism for water shut-off (or other isolation requirements), and completion control by remote intervention or RLWI.
   - A low-cost diverting agent using MEOR technology for injection well profile control needs.
4. Evaluate the necessary modifications to the current sulfate reduction nano-filtration technology to make low salinity waterflooding possible. Determine candidate reservoirs and fields, and consider the use of shared infrastructure in mature areas with limitations of space and weight on production platforms.
   - Fund research to assess a “brownfield” implementation of LowSal in the Chevron/Marathon Petronius field for tertiary recovery. The study group could include operators from the nearby Neptune, King, Swordfish, Horn Mountain, and Ram Powell fields to gauge interest in the use of a shared facility for low salinity water supply.
5. There is a need for R&D for the development of a reliable, downhole deep-set pump installation for a Paleogene well to deliver higher rates and to lower abandonment pressure. Due to the depth and pressure, investigate the development of a hydraulic

submersible pump which can deliver high delta pressure while not requiring downhole electrical connections. Otherwise, consider an electric submersible pump (ESP) with rigless access operable in a high temperature environment.

6. Microbial EOR (MEOR) technology is a potentially low-cost diverting agent for conformance control in heterogeneous formations with highly-stratified lithology. There is uncertainty in the field-scale stimulation and growth of microbes with IOR benefits particularly the operating dimensions of an engineered MEOR application. Microbial reactions are also linked to lowering of the residual oil saturation and oil viscosity reduction. Fund research to evaluate the use of MEOR including:
   - Determine the interplay of chemical and biological controls (reservoir chemistry, nutrient concentration, growth period etc.).
   - Establish operating scope for various strains deployed in different in-situ conditions.
   - Quantify the impact of formation temperature on microbial performance in the near-wellbore region. Assess the feasibility of thermophilic microbes for use up to 250 °F.
   - Identify enzyme-producing microbes aimed at reducing Sor and improving sweep efficiency in a field-scale displacement process.
   - Evaluate microbial visbreaking of low API crude oil.
7. Nitrogen injection has both secondary and tertiary recovery benefits but has not been employed offshore due to the large space and weight requirements for air extraction equipment.
   - Fund research to develop the technology of advanced nitrogen extraction from air for use on deepwater facilities and at reasonable/low cost, weight, and footprint.
8. A gap exists in the hydraulic fracturing technology used onshore for ultra-low permeability reservoirs insofar as transferring these techniques to Paleogene reservoirs for a similar gain in the productivity index.
   - Fund research in coordination with operators and service providers for the development of Paleogene hydraulic fracturing technology to increase initial well PI by factor of 3 to 5 times the current expectations.

Nomenclature

Table 49: Nomenclature

ϕ	Porosity
°API	Degrees API
°F	Degrees Fahrenheit
Δp	Pressure differential
AAPG	American Association of Petroleum Geologists
AOP	Asphaltene onset pressure
API	American Petroleum Institute
ASP	Alkaline-surfactant-polymer
ATCE	Annual Technical Conference and Exhibition
bbl	Barrel
BBOE	Billion barrels of oil equivalent
BCFD	Billions of cubic feet per day
BHP	Bottomhole pressure
BOE	Barrels of oil equivalent
B_{oi}	Initial formation volume factor
BOPD	Barrels of oil per day
BSCF	Billions of standard cubic feet
BSTB	Billions of stock tank barrels
BTU	British thermal unit
BWIPD	Barrels of water injected per day
bwpd	Barrels of water per day
C_1	Methane
C_{12}	Uodecane
C_2	Ethane
C_3	Propane
C_5	Pentane
C_6	Hexane
$CaCO_3$	Calcium carbonate
CAPEX	Capital expenditure
CO2	Carbon dioxide
cp	Centipoise

C_r	Rock compressibility
C_t	Total compressibility
DW	Deepwater and ultra-deep water
EOR	Enhanced oil recovery
ESP	Electrical submersible pump
EUR	Estimated ultimate recovery
FAWAG	Foam-assisted water-alternating-gas
FBHP	Flowing bottomhole pressure
Fe_xS_y	Iron sulphide compound
FPSO	Floating production storage and offloading
ft	Feet
FVF	Formation volume factor
GCSSEPM	Gulf Coast Section SEPM
GL	Gas lift
GOM	Gulf of Mexico
GOR	Gas-to-oil ratio
GR	Gamma ray
H_2S	Hydrogen sulphide
HC	Hydrocarbon
HCPV	Hydrocarbon pore volume
HP	High pressure
HT	High temperature
IFT	Interfacial tension
IOR	Improved oil recovery
k	Permeability
k_h	Horizontal permeability
k_v	Vertical permeability
LowSal	Low salinity water injection
LSU	Louisiana State University
md	Millidarcies
MEOR	Microbial enhanced oil recovery
MIE	Multi-component ion exchange
MMB	Million barrels
MMBOE	Million barrels of oil equivalent
MMBW	Millions of barrels of water

MMP	Minimum miscibility pressure
MMS	Minerals Management Service
MMSCF/d	Millions of standard cubic feet per day
MMSTB	Millions of stock tank barrels
N	Volume of oil originally in the reservoir
N/G	Net-to-gross
N_2	Nitrogen
Na_2CO_3	Sodium carbonate
NAB	MMS National Assessment Brochure
NaOH	Sodium hydroxide
NCS	Norwegian Continental Shelf
NETL	National Energy Technology Laboratory
N_p	Volume of oil produced
NPC	National Petroleum Council
NTG	Net-to-gross
NTNU	Norwegian University of Science and Technology
OCS	Outer Continental Shelf
OG21	Board established by the Norwegian Ministry of Petroleum and Energy
OGIP	Original-gas-in-place
OOIP	Original-oil-in-place
OTC	Offshore Technology Conference
OWC	Oil-water contact
P10	10% probability
P10 IOR R.F.	high technical IOR recovery factor
P50	50% probability
P50 IOR R.F.	(P90 IOR R.F. + P10 IOR R.F.) / 2
P90	90% probability
P90 IOR R.F.	Low technical IOR recovery factor
P_b	Bubble-point pressure
P_i	Initial pressure
PI	Productivity index
ppm	Parts per million
P_r	Reservoir pressure
P_{sat}	Saturation pressure

psi	Pounds per square inch
psia	Absolute pressure in pounds per square inch
psig	Gauge pressure in pounds per square inch
PV	Pore volume
PVT	Pressure-volume-temperature
R&D	Research and development
RB	Reservoir barrels
RF	Recovery factor
RLWI	Riserless light well intervention
ROIP	Remaining-oil-in-place
RPSEA	Research Partnership to Secure Energy for America
SCADA	Supervisory control and data acquisition
scf	Standard cubic feet
SEPM	Society of Economic Paleontologists and Mineralogists
s_{oi}	Initial oil saturation
s_{or}	Residual oil saturation
SPE	Society of Petroleum Engineers
SRB	Sulfate-reducing bacteria
SS	Subsea
SSBI	Subsea separation, boosting, and injection
stb	Stock tank barrels
STB/d	Stock tank barrels per day
SWAG	Simultaneous water-and-gas
s_{wi}	Iinitial water saturation
TAC	Technical Advisory Committee
THP	Tubing head pressure
TIFF	Tagged image file format
TRF	Technical readiness factor
TRL	Technical readiness level
TTA3	OG21 Technology Target area 3 (enhanced recovery)
TTA4	OG21 Technology Target area 4 (cost effective drilling and intervention)
TVDSS	Total vertical depth subsea
UERR	Undiscovered economically recoverable resource
URF	Ultimate recovery factor

US	United States
USD	U.S. dollars
USGS	United States Geological Survey
WAG	Water-alternating-gas
WOR	Water-oil ratio

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Appendix A: Simulation Sector Model

Neogene Reservoir Sector Model

A sector model was constructed to use for predicting improved oil recovery. The field data of the deepwater GoM Neogene age reservoirs were extensively searched through various public resources (ReservoirKB, MMS, AAPG, and etc.) to provide ranges of model input properties. The input data represent ranges of properties observed in Mars, Atlantis, Ursa, Horn Mountain, Mad Dog, Thunder Horse, Tahiti, K2, and Shenzi fields. Fluid PVT is based on correlations used to match known reservoir pressure, temperature, and oil API and bubble point.

Simulation Model

The geologic model is built using field type logs representing high, medium and low case net/gross sand ratios. The model contains X=26, Y=26, Z=58 grids with dimensions of 5000 ft by 5000 ft by 300 ft thick (Figure 76). The model has a layer thickness and properties defined using a type log from the Tahiti field, M21A and M21B reservoirs (Figure 77). The model contains a shale layer separating upper and lower zones. An estimate was made for porosity to permeability relationship based on other deepwater Gulf of Mexico published trend data.

The model includes one updip producer and a downdip injector for the cases with injection. The model OOIP is 68.4 MMSTB, and there is 54.7 BSCF associated OGIP representing a GOR of 800 SCF/STB.

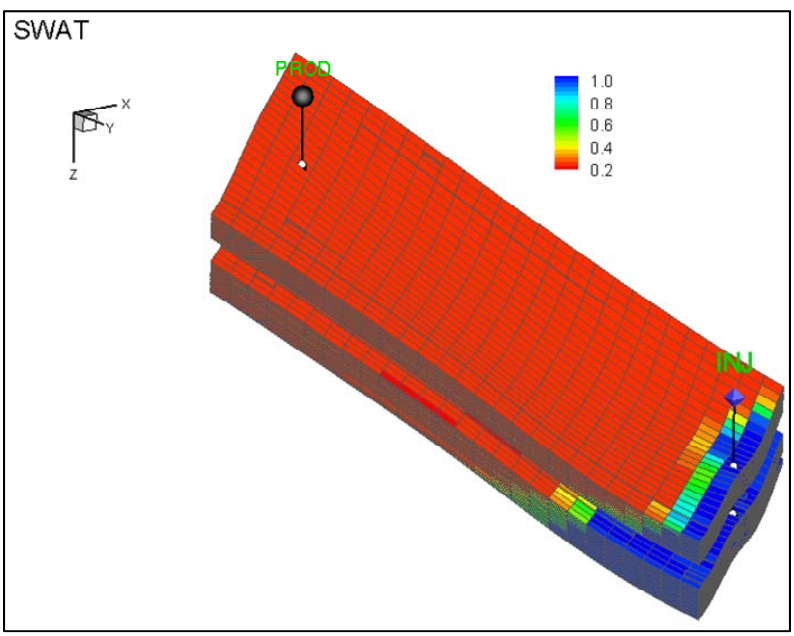

Figure 76: Initialized sector model for simulation of Neogene IOR potential

A simple depositional facies model was populate including sheet sand, distal sheets, and shale (Figure 77). The well log motifs and properties were used to pick the facies and some slight variation was populated in the model away from the single well control point. For the most part the model is layer-cake where each layer facies and rock properties are close to those observed on the type well log at that depth.

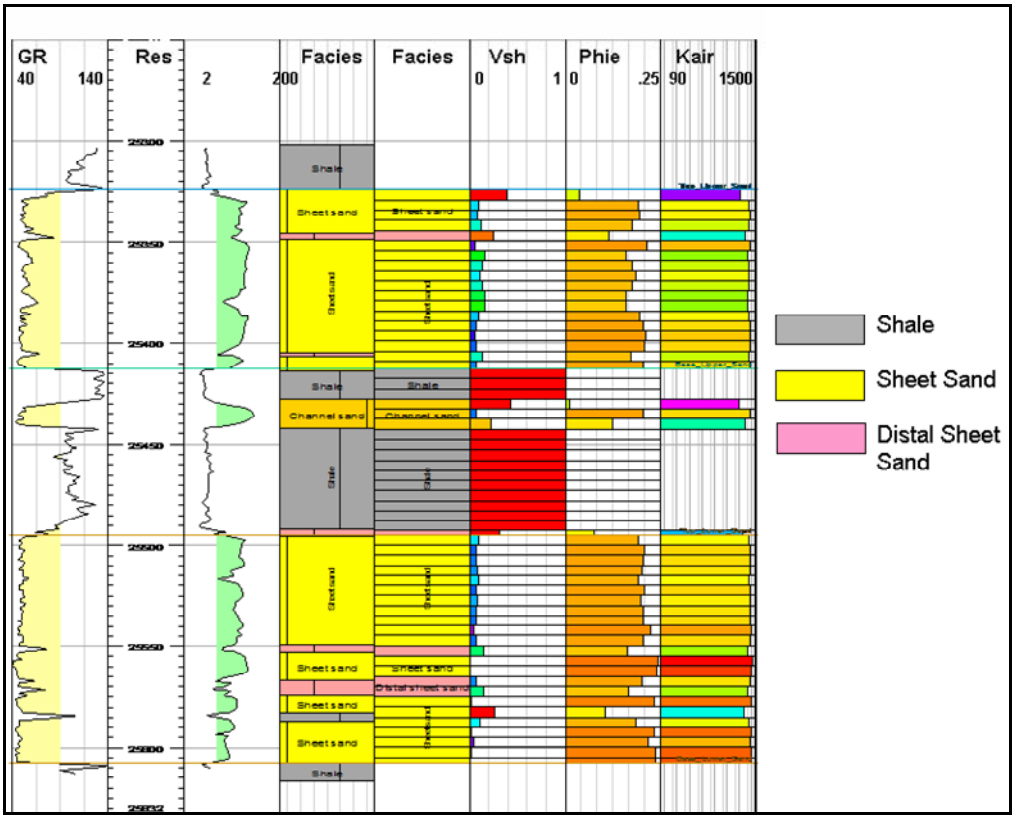

Figure 77: Type log from Tahiti field used to define sector model Neogene properties

The model has an average permeability of 800md, and a cross-section view of permeability change with depth is shown in Figure 78.

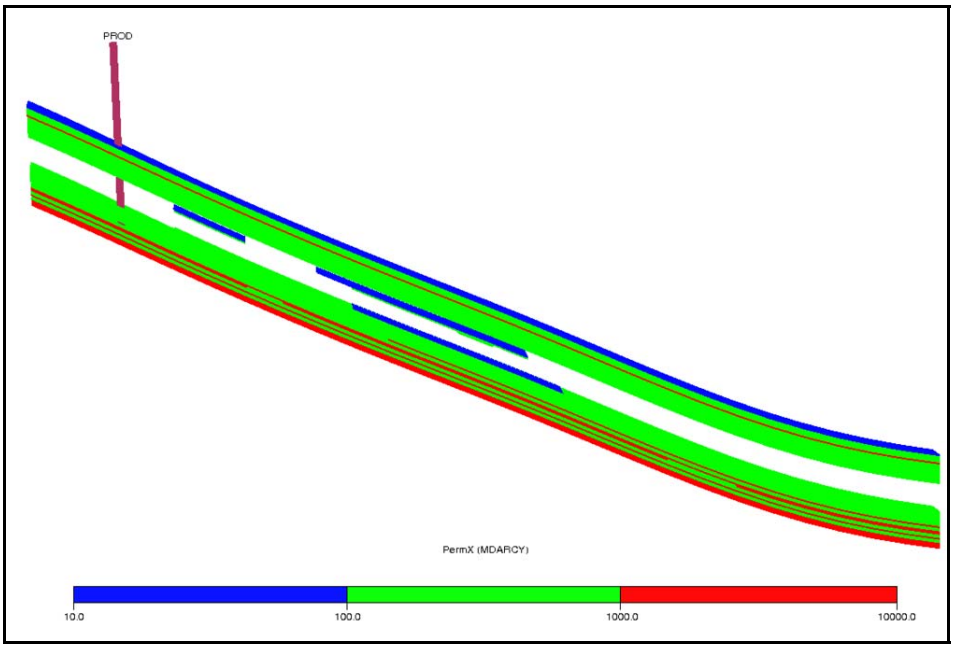

Figure 78: Neogene model permeability

The vertical permeability is set using a Kv/Kh ratio of 0.1. The proxy model includes a fault, without displacement, between the updip producer and the downdip region. The transmissibility across the fault is controlled to act as a flow barrier which will reduce the drainage area and totally or partially block the communication between the producing wells and injection wells or aquifers. The model assumes some reduction of transmissibility (multiplier of 0.7) between the updip production well area and the aquifer/injector well.

A minimum size natural aquifer is included representing 0.40 x hydrocarbon pore volume (HCPV). Most of the upper Tertiary reservoirs are unconsolidated and present very high pore volume compaction. The model rock compressibility is 38 E-6 psi-1 based on published information (Pourciau 2003, Ring 2003 and Ostermeier 2001). Porosity and permeability reduction with declining reservoir pressure are modeled in the simulation.

Oil-water and gas-oil relative permeability and capillary pressure curves were derived using endpoints representative of data observed for deepwater Gulf of Mexico. The curve shapes were defined using Corey exponents. A summary of the endpoint data is show in Table 50.

Table 50: Neogene model relative permeability endpoint data

Swirr	Swcr	Swmax	Sgl	Sgcr	Sgu	Sorw	Sorg
0.20	0.20	1.00	0.00	0.05	0.75	0.25	0.25
Water Krw at SWU	**Gas Krg at SGU**	**Oil Kro at SWMIN**	**Water Krw at SORW**	**Gas Krg at SORG**	**Oil Kro at SGCR**	**Oil Kro at SWCR**	
1.00	0.46	1.00	0.40	0.55	0.98	1.00	

Conventional Waterflood IOR

Initially, the model was used to match a typical performance for a highly compacting reservoir with limited aquifer influx and no water injection. The primary recovery was then compared to a number of simulations with a downdip injector assuming various voidage-replacement ratios.

For waterflood cases, the injector is started after 1.5 years of production. The injection voidage is set to 0.6, 0.9, 1.0 and 1.1 times as the production voidage. The economic limit of well was initially set at 80% water cut but a sensitivity to RF is included for a higher water-cut limit of 90%.

The primary oil RF is 38.8% which is similar to the forecast of primary oil recovery for the Mars N/O sand from volumetrics and decline analysis prior to the start of injection. The waterflood IORs range from 12 to 18% based on voidage replacement ratios of injection. The incremental oil is the not proportional to the voidage replacement ratio because the economic limit setting. The higher voidage replacement ratio causes water cut reaches economic limit earlier.

When the economic limit is reset to 90% water cut, the incremental recovery over primary production ranges from 14.9% - 21.8%. The results of sensitivity to water-cut limit are shown in Table 51. The simulated incremental RF for waterflood after depletion in a highly compacting reservoir validate the estimates observed from reviewing waterflood performance in deepwater GoM fields.

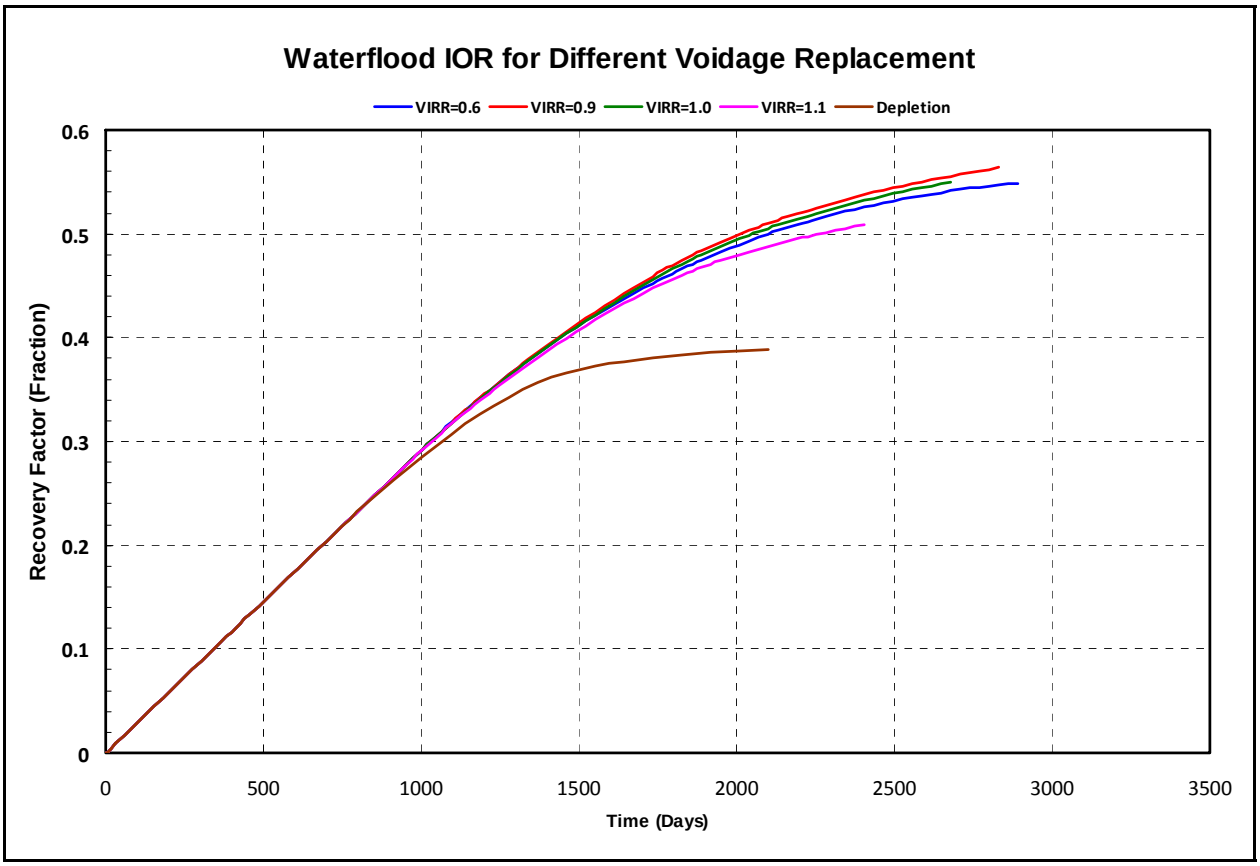

Figure 79: Simulated waterflood incremental oil RF compared with primary recovery

Table 51: Waterflood RF at different water-cut limits

	Waterflood IOR			
	VIRR=0.6	VIRR=0.9	VIRR=1.0	VIRR=1.1
Water cut = 80%	54.8%	56.3%	54.9%	50.9%
Water cut = 90%	54.9%	60.6%	58.7%	53.7%
Incremental Oil	0.1%	4.3%	3.8%	2.8%

Secondary Low Salinity Water Injection

The cross-section model is used to forecast the incremental recovery potential from low-salinity water injection. The predictions are hypothetical given no core data or field trials for which to determine the potential Sor reduction or the change in relative permeability curve shape.

The low-salinity model consists of the following capabilities:

- Salt is modeled as an additional single lumped component in the aqueous phase which can be injected and tracked. The viscosity and density of the aqueous phase is dependent on salinity.
- Relative permeability and capillary pressure were made a function of salinity. There is no dependency at high or low-salinity. The high and low relative permeabilities are two inputs. Shapes are interpolated in between (Figure 80). The relative permeability curves display the characteristic behavior found in the many corefloods of more favorable fractional flow behavior and a similar water relative permeability at high and low-salinity residual oil saturation. Residual oil saturation as a function of is input as a table.

The simulation is run where low-salinity water is injected in secondary recovery mode after one and half year depletion. The LowSal injection was run with different voidage ratios. The results of incremental oil recovery for low-salinity water injection versus convention seawater injection are shown in Table 52.

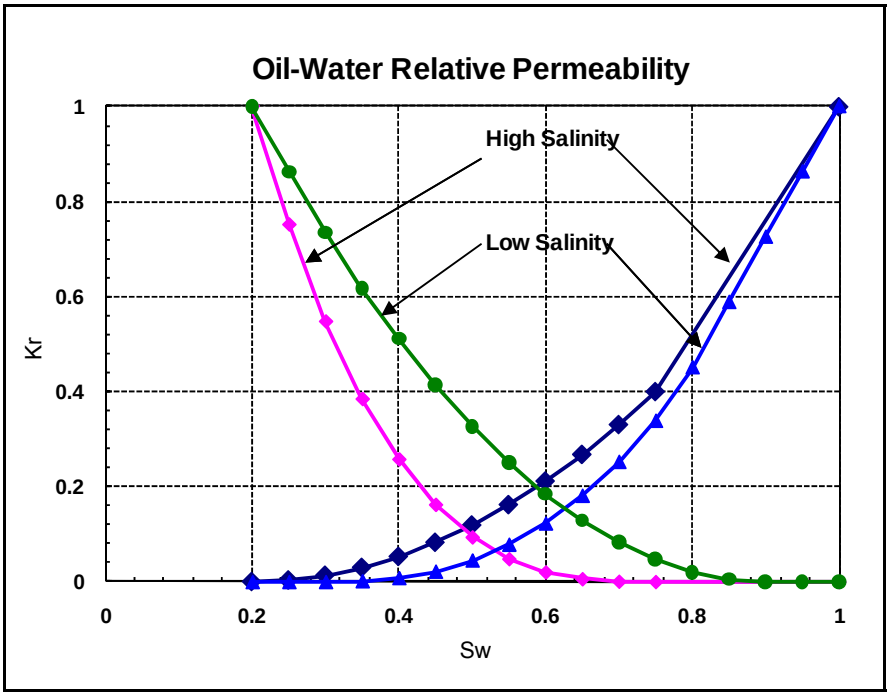

Figure 80: Relative permeability curves for seawater and low-salinity water

Table 52: Recovery by seawater injection vs. low-salinity water injection

	Waterflood IOR			
	VIRR=0.6	VIRR=0.9	VIRR=1.0	VIRR=1.1
Convention	54.8%	56.3%	54.9%	50.9%
LowSal	57.7%	63.4%	61.8%	56.1%
Incremental Oil	2.9%	7.1%	6.9%	5.2%

Paleogene Reservoir Sector Model

The Paleogene sector model is based on digitized well logs from the Jack field appraisal well #2. Logs were available as TIFF images from the MMS and include GR, intermediate and deep resistivity and sonic. Well tops were published by Stromboe et al. 2007. A simple facies model with clean sand, shaley sand and shale is defined based on cut-offs of volume of shale (Vsh). The Jack #2 log and facies are shown in Figure 81.

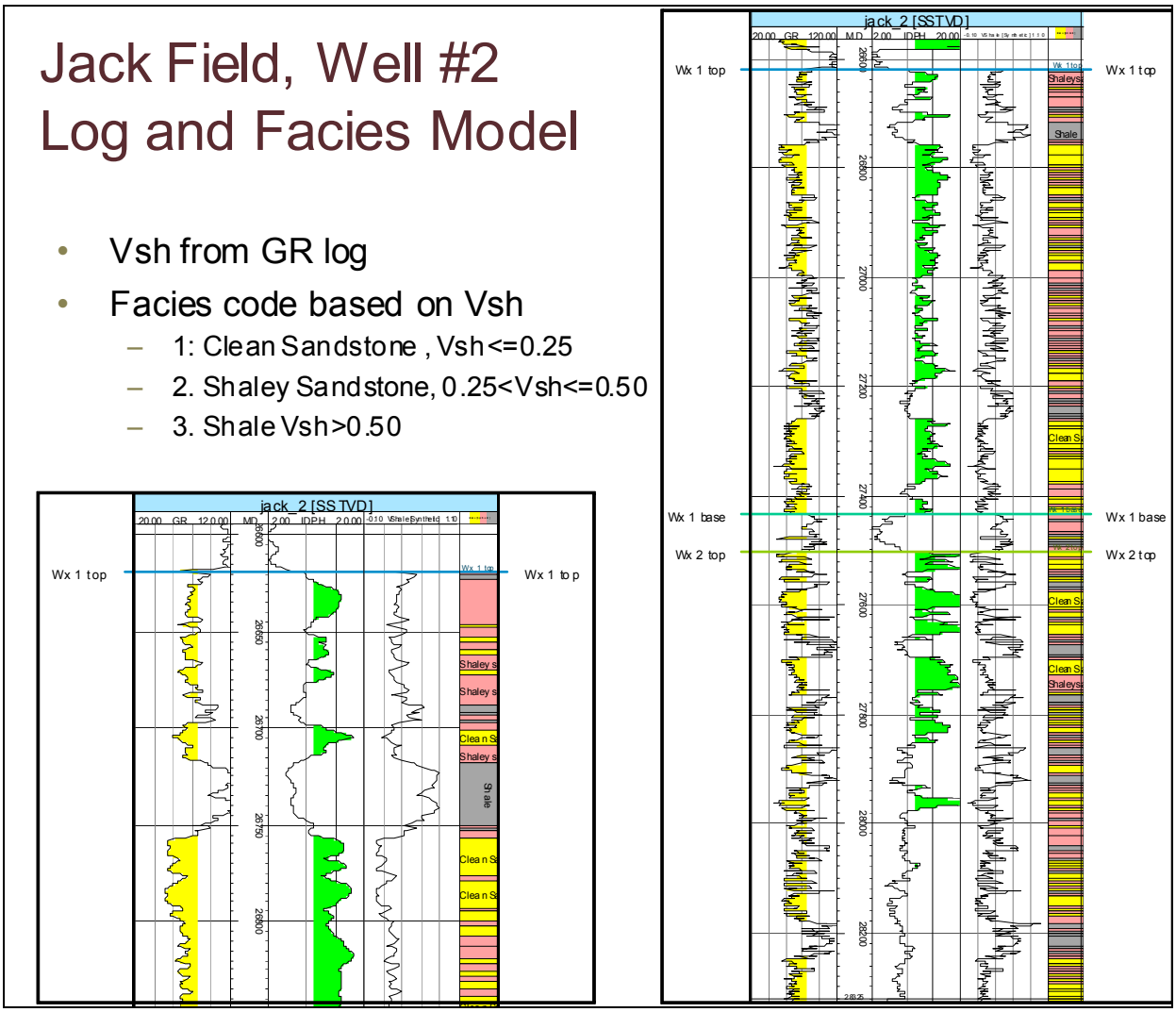

Figure 81: Jack #2 well, basis for Paleogene sector model

Simulation Model

A simulation model is a simple rectangular outline with 100 ft x 100 ft cells. There were 7 cells across and 27 cells long. The model has three zones (Table 53) based on the surfaces and well tops. The layering was made 1 ft increments to preserve vertical heterogeneity. The model size is 670 ft x 2673 ft x 1818 ft bulk volume (Figure 82). The left panel shows the grid depth while the right panel is initial oil saturation. The total number of cells is 343,602.

A summary of model input and a cross-section showing initial oil saturation and the different oil-water contacts used for Wilcox 1 and 2 zones is shown in Figure 83. The permeability model is

derived using a relationship with porosity. A model view of permeability is shown in Figure 84. The Mean permeability is 1.9 mD, maximum is 155 mD, and minimum is 0.00.

Table 53: Paleogene model zones, layers, OWC and OOIP

Zone Number	Current Name	Model Layer	OWC TVDss	OOIP MMSTB
1	WX1	1-817	27850	6.4
2	WX Shaly	818-887	27850	0.009249
3	WX2	888-1818	28900	6.86

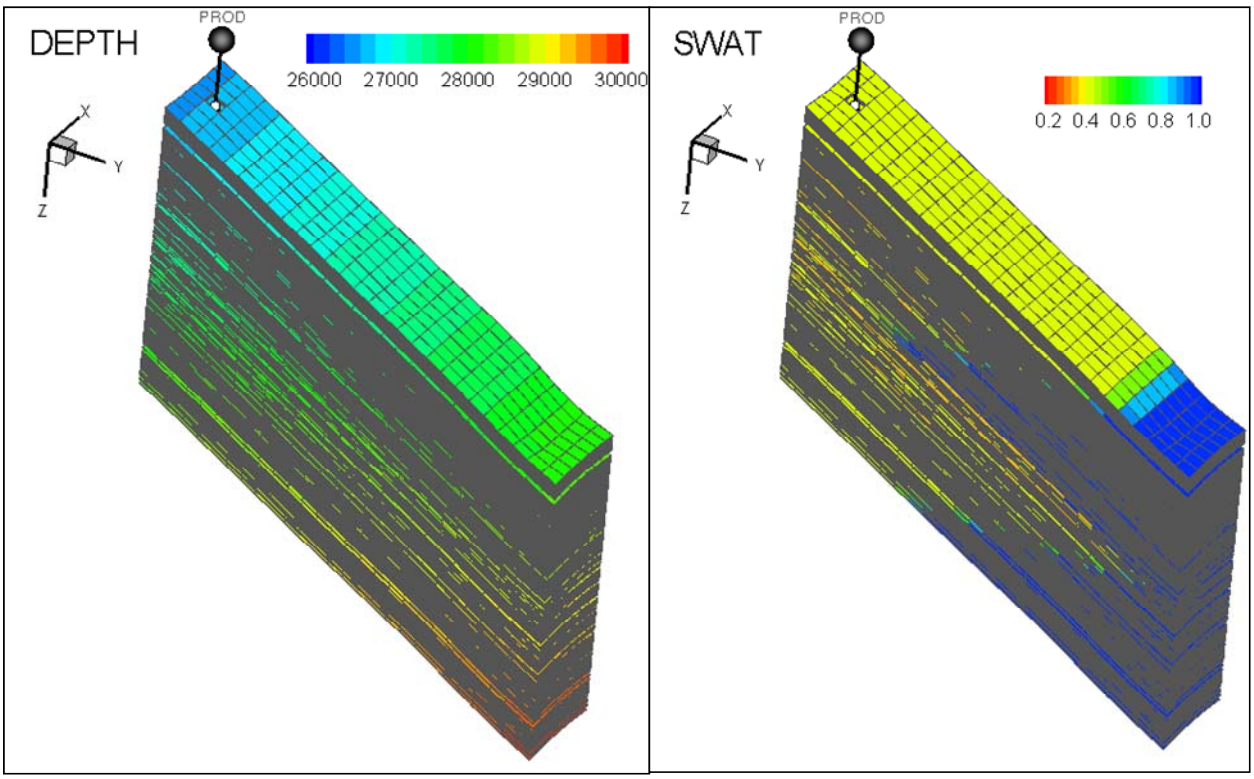

Figure 82: Paleogene cross-section model views

- Model based on Walker Ridge rock and fluid properties as determined from public forums
- Depth 28,000 ft (Jack #2 well)
- Pr = 19,500 psi
- Psat = 2000 psi
- GOR = 350 scf/stb
- Oil viscosity = 5 cp at Pi
- OOIP = 13.5 MMSTB
- Cr = 2.5 microsips

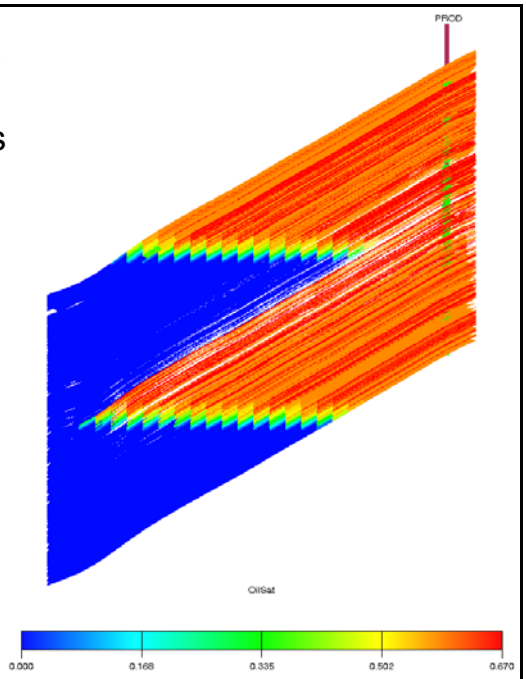

Figure 83: Cross-section view of Soi, oil-water contacts, and basic model data

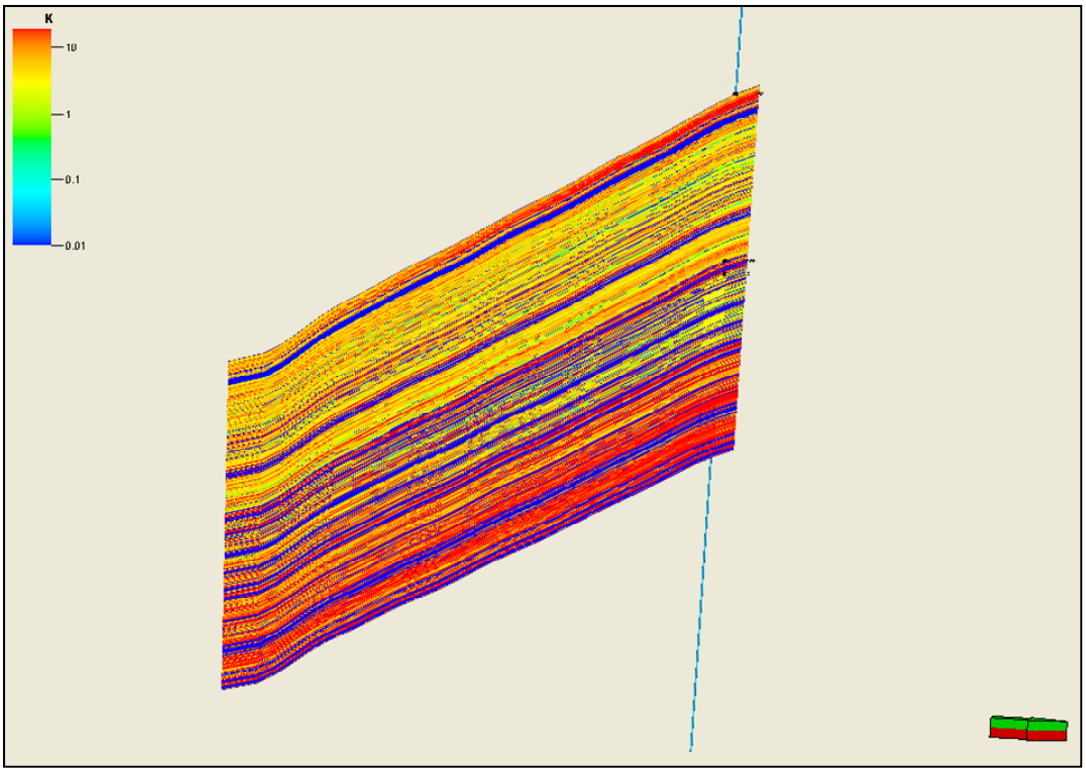

Figure 84: Paleogene model permeability

The relative permeability used to initialize the model is shown in Figure 85. Different curves are used for clean sand, shaley sand and shale.

The fluid properties were derived from correlations using the GOR, reservoir pressure and temperature, oil API and an assumed low bubble point pressure of 2000 psia. The resulting oil formation volume factor and oil viscosity data is shown in Figure 87 and Figure 88.

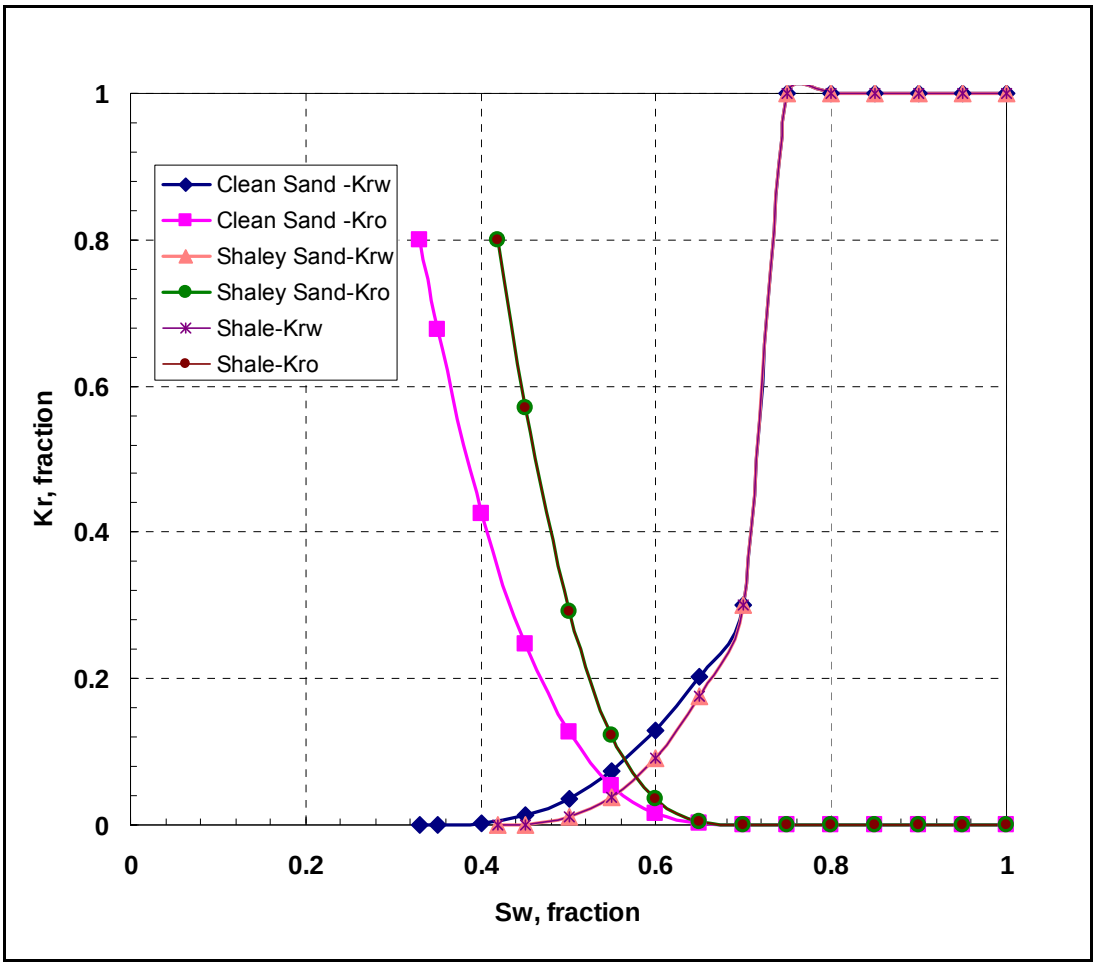

Figure 85: Oil-water relative permeability in Paleogene model

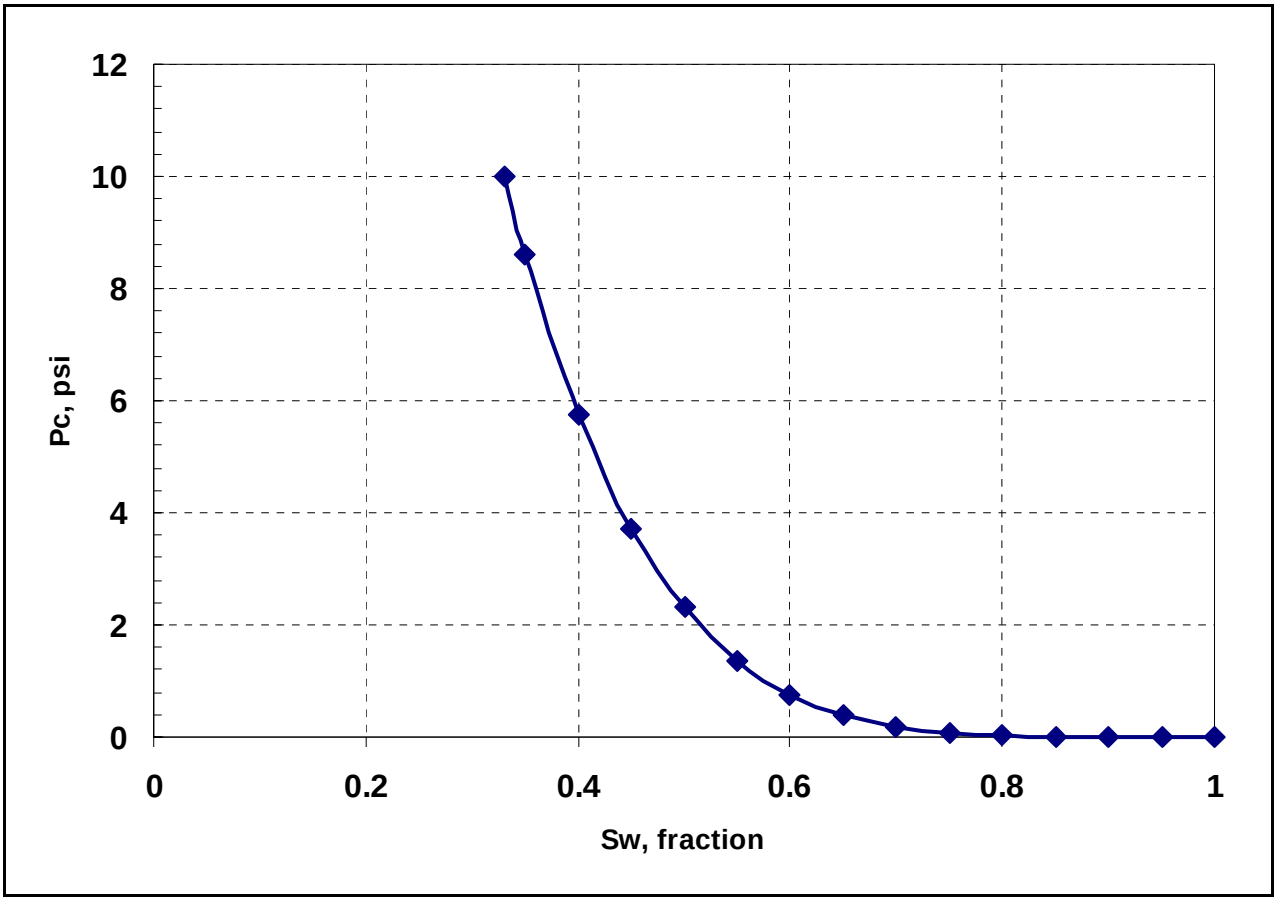

Figure 86: Assumed capillary pressure curve

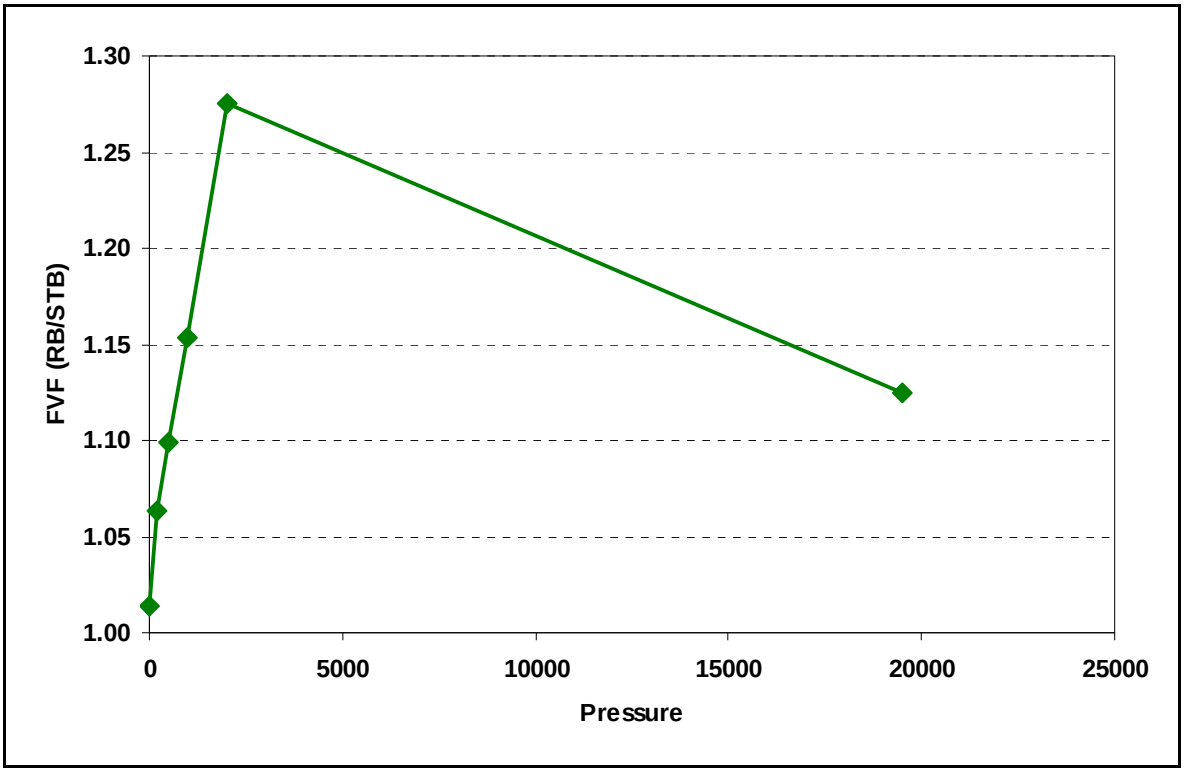

Figure 87: Oil FVF from correlation, Paleogene model

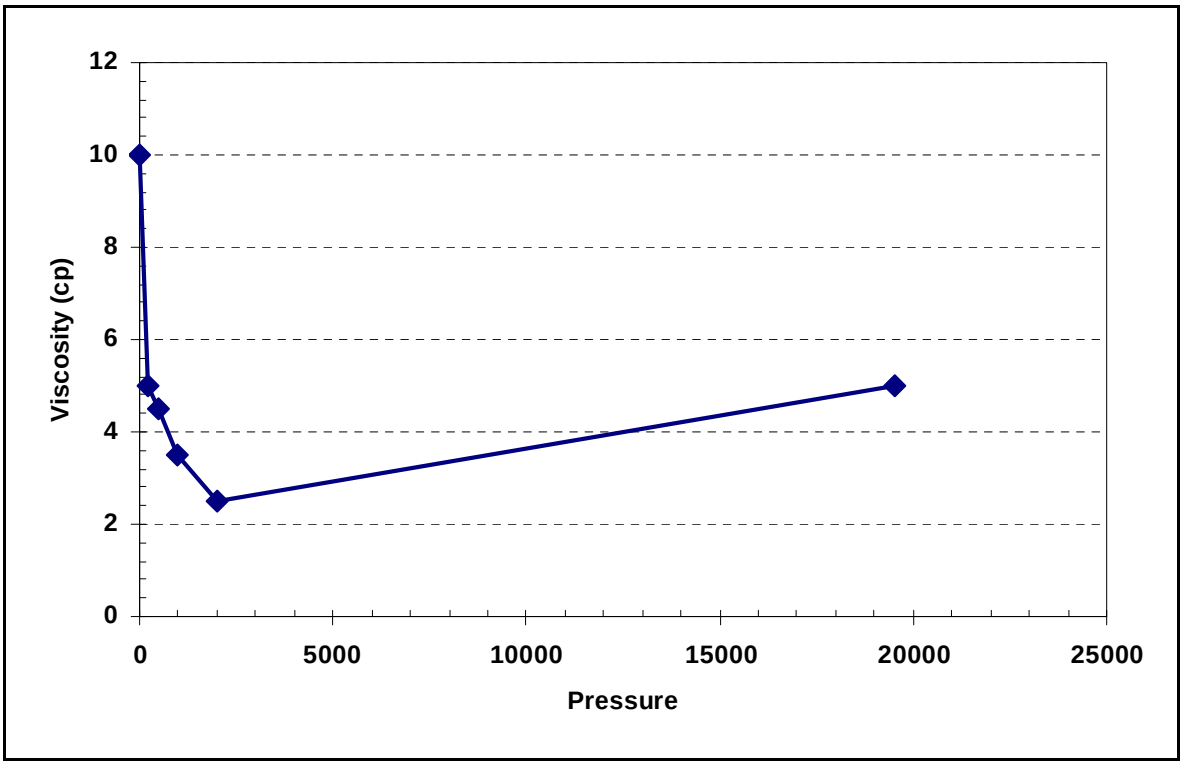

Figure 88: Oil viscosity estimated for Jack field

Depletion Forecast

The model was run to predict rate and recovery for primary production. The oil recovery is 12% of OOIP. The oil rate quickly declines with no production plateau (Figure 89). The peak oil rate is 8,100 STB/d and the well has an initial PI of 1.5 STB/d/psi. The initial pressure draw-down near wellbore was about 8,000 psi. The dominated drive mechanism is oil expansion.

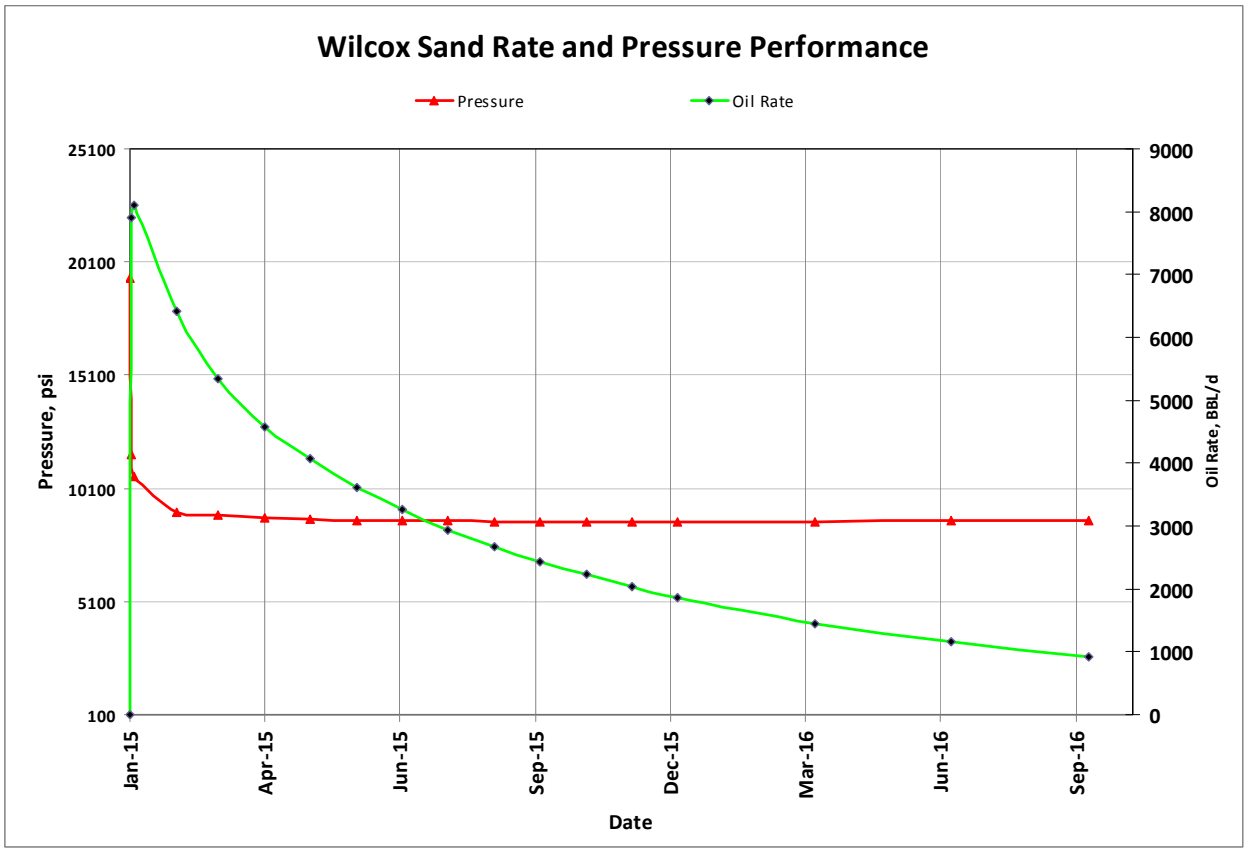

Figure 89: Paleogene primary recovery forecast

Paleogene Field IOR Forecast

Five Paleogene IOR processes were investigated using the Jack model to determine incremental recovery (Table 54).

Table 54: IOR cases investigated in Paleogene model

Process Number	IOR Category	IOR Process
1	Water Injection	Conventional Water Injection
2	Pumping & Artificial Lift	Subsea Multi-Phase Pumping
3		In-Well ESP
4		In-Well Gas Lift
5		Riser Based Gas Lift
6	Well Technology	Hydraulic Fracturing

Conventional Water Injection

Water injection is initiated after one year of production due to high initial reservoir pressure. , the performance of the reservoir is illustrated in the following plots of pressure, oil rate, water injection, drive mechanisms and cumulative production.

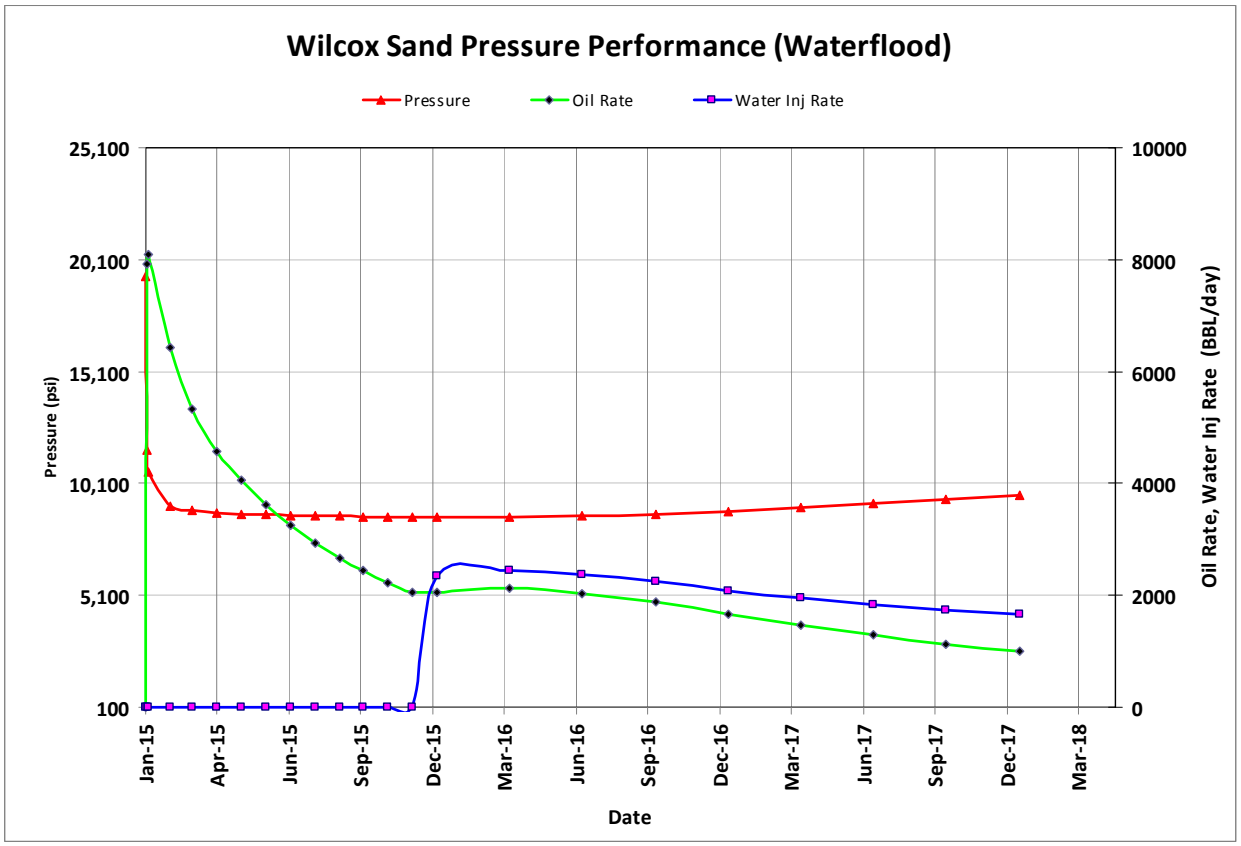

Figure 90: Waterflood performance of pressure, oil rate and water injection rate

The oil rate quickly declined from 8,100 STB/d to 2,045 STB/d in one year. The production rate became stable after water injection started. The well was shut in after more than two-year production after oil rate dropped to less than 1,000 STB/d. The peak production rate is 8,100 STB/d during depletion, average rate 2,264 STB/d. The water cut was 35% when the well was abandonment (Figure 90). The reservoir is driven by fluid expansion early on and then by the engineered water injection (Figure 91). The waterflood oil recovery factor is 18.6% of OOIP and the incremental over primary production is 6%.

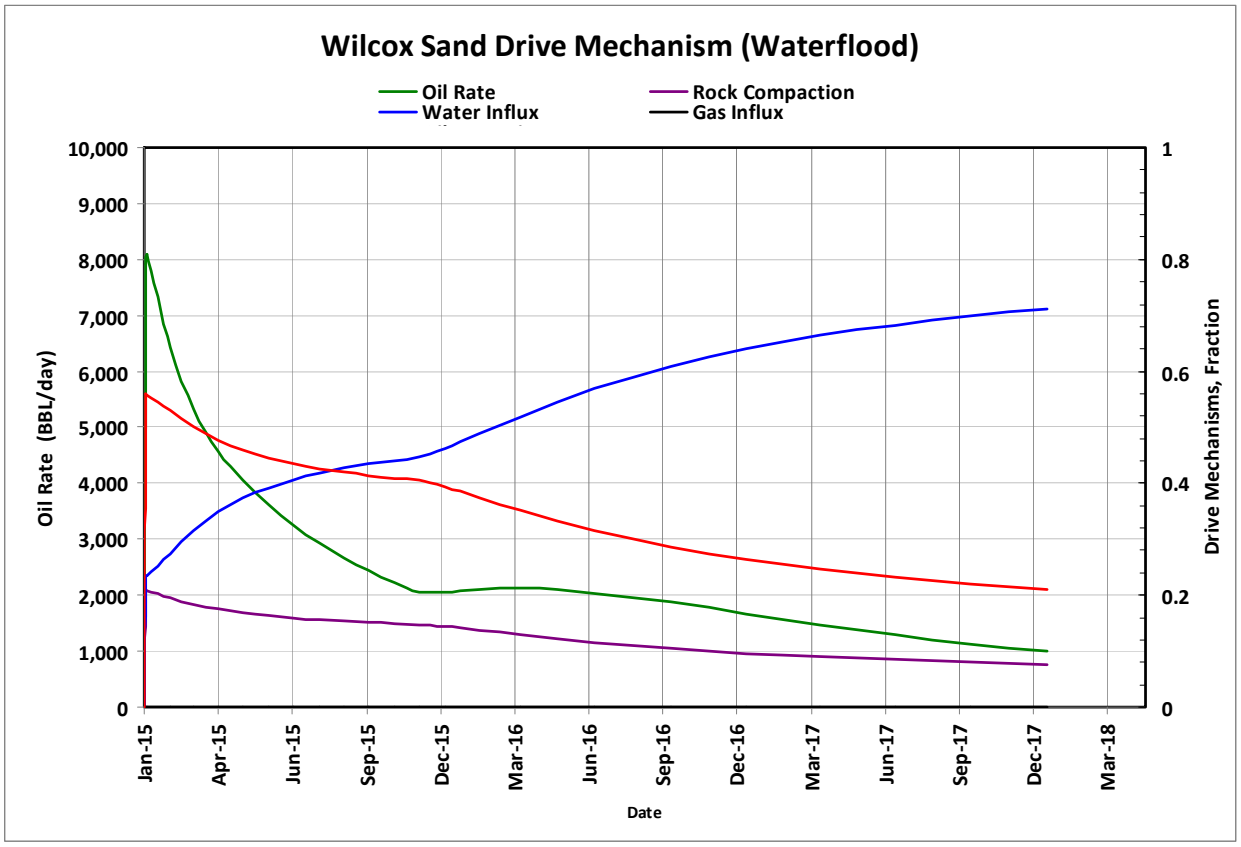

Figure 91: Producer oil rate and drive mechanisms with waterflood

Pumping & Artificial Lift

Due to the high abandonment pressure and low water cut, the simulation of artificial lift is included by electrical submersible pump (ESP) and gas lift.

The in-well ESP was designed using Prosper with the input data summarized in Table 55. The REDA-S8900N is chosen with 216 stages. The tubing inside diameter is 3.6 inches. The outer diameter of ESP is 6.5 inches. The design is validated by calculating sensitivities. The efficient operation at the design rate can be achieved over the entire range of expected well and pump efficiency conditions. Figure 92 demonstrated the ESP can accommodate future changes of the well production rate.

Table 55: Input data for in-well ESP design

Pump Depth (measured)	25,000	ft
Design Rate	6,000	STB/day
Top Node Pressure	250	psi
Head Required	8,518	ft
Average Downhole Rate	6,974	RB/day
Pump Inlet Temp	230	°F
Pump Inlet Pressure	5,506	psia
Pumb Discharge Pressure	8,443	psia

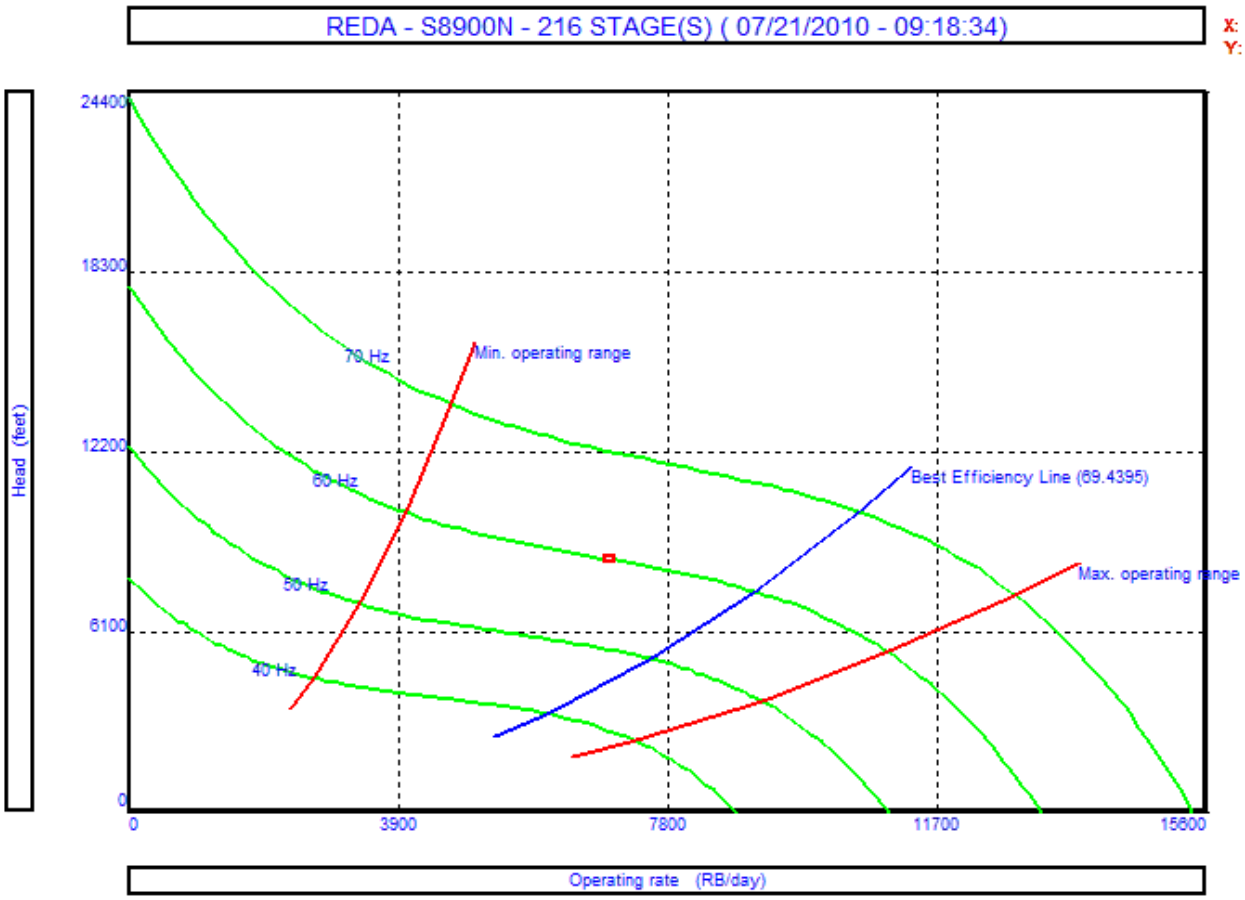

Figure 92: ESP design curve for in-well Paleogene installation

The forecast of primary production with and without a downhole ESP is shown in Figure 93. The oil recovery factor is 17.4% with the ESP around 6% more oil recovery than the primary production scenario.

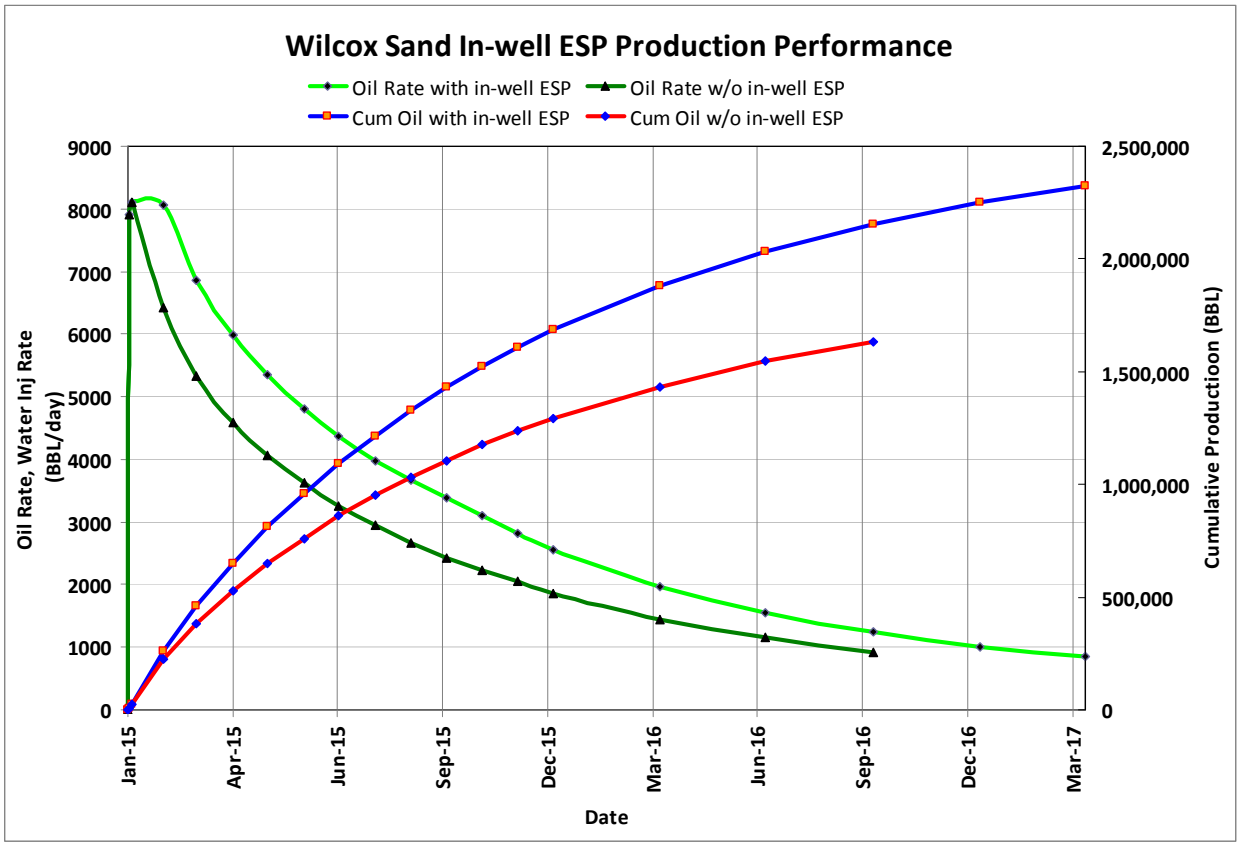

Figure 93: Oil rate and cumulative with and without ESP for primary production

ESPs are traditionally used in oil wells to improve production as an artificial lift method, but recently have been used to boost production on the seafloor from subsea well head to host facilities. The seafloor boosting with ESP can be installed at the base of subsea risers, in seafloor caisson gas-liquid separators, or near the production well manifold. A case is simulated here to compare an ESP at the base of a riser versus the installation downhole. It is modeled that the subsea wellhead is 11 miles from the host facility.

The simulated performance is shown in Figure 94. Oil recovery factor is 16.3% for the case with the ESP at the base of the riser. The incremental oil is 5% over the depletion case without artificial lift but 1% less oil recovery than the case with the ESP in-well.

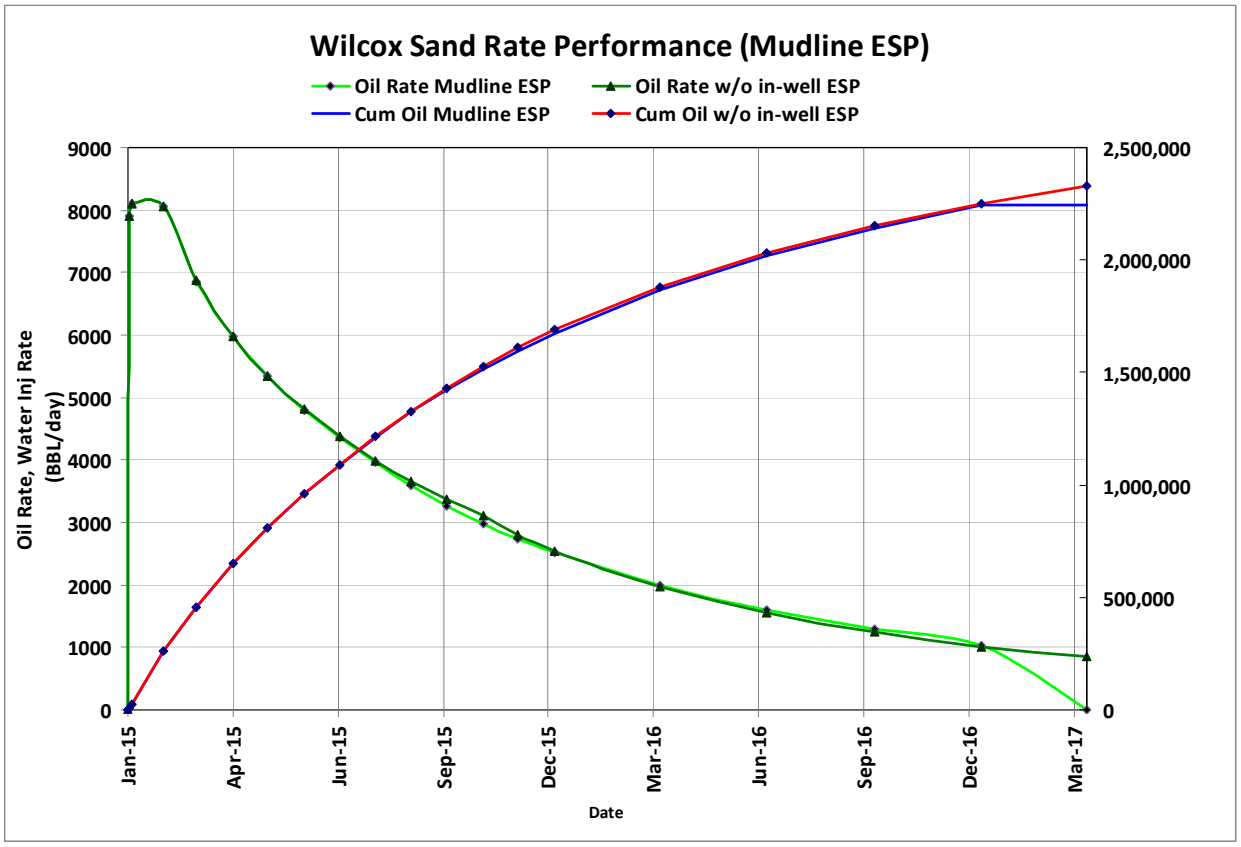

Figure 94: Producer oil rate and cumulative oil by ESP at Mudline with ESP in well

The use of gas-lift inside of a production riser has been employed in subsea operations, and is a proven method to increase and stabilize production rates. The injection of the gas into the flowstream, at the base of riser, lightens the fluid column.

The recovery factor is 12.2%, which is 0.2% incremental oil over the depletion case with no artificial lift. The benefits for gas lift were minimal since no water was produced.

In-Well Gas Lift

In the in-well gas lift case, the mandrel is installed at 25,000 TVD ss. The injected gas rate is set as 5 MMcf/day. The EUR is 1.66 MMSTB and incremental oil is negligible (Figure 95). It proves that the gas lift is not an efficient artificial lift downhole and a large offset from the host facility. Gas lift applications are limited due to higher required operating pressure than current design rated to 5,000 psi.

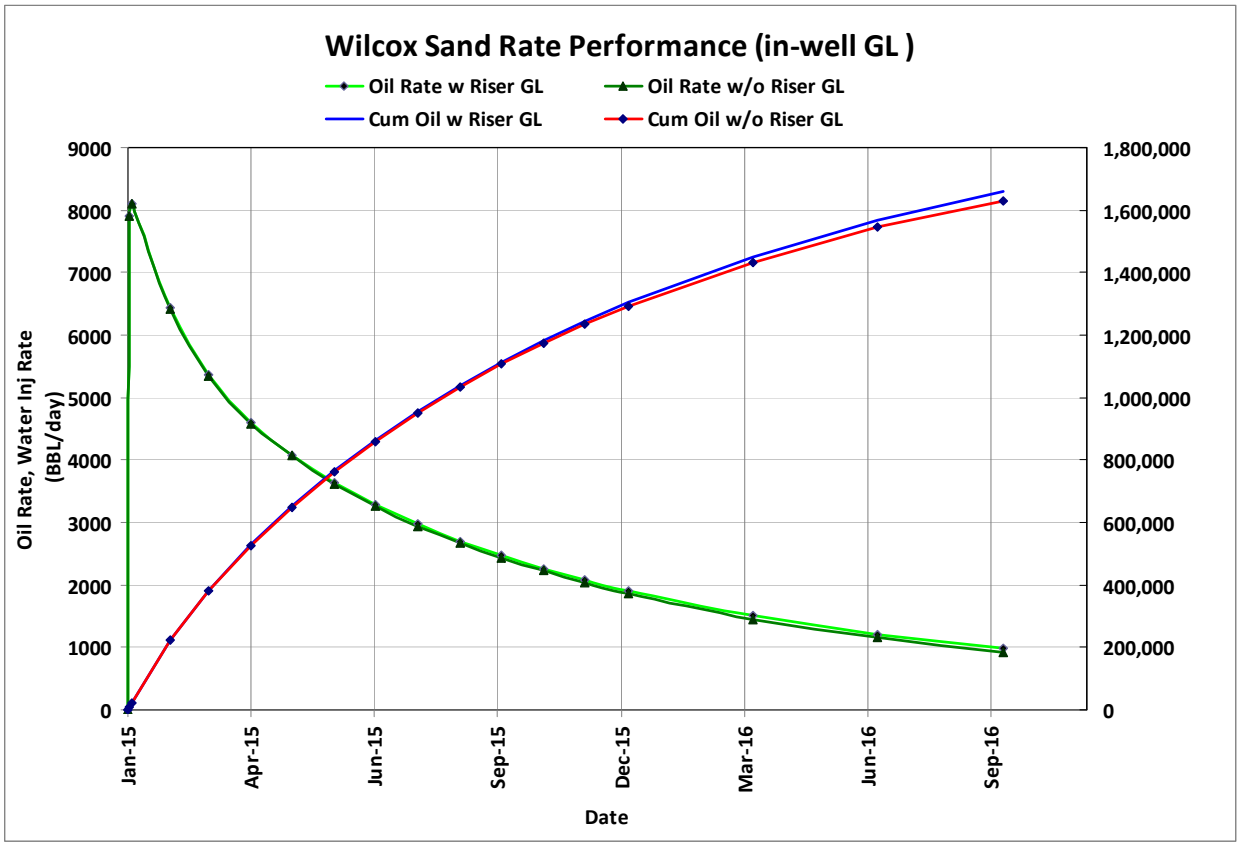

Figure 95: Producer oil rate and cumulative oil by ESP at Mudline with GL in well

Well Technology – Hydraulic Fracturing

The implementation of a massive hydraulic fracture was modeled simply by assigning skin factor equal to -3. In base case, the skin factor of +3 is used to simulate no hydraulic fracturing. The incremental oil is 0.6%. The PI after hydraulic fracturing operation can reach 9 bbl/d/psi (versus the base case of 1.5 bbl/d/psi).

The peak production rate reaches 15,000 bbl/d which is twice as much as no hydraulic fracturing scenario. But the production rate declined dramatically due to lack of reservoir energy. Therefore the combination of water injection, hydraulic fracturing and artificial lift would enhance more oil recovery. The hydraulic fracture was also model by modifying directional permeability near wellbore. The fracture half length is assumed as 150 ft. The permeabilities of wellbore and nearby blocks in X-direction have been multiplied by 10. The PIs in two cases are both equal to 8 bbl/d/psi. The EURs are the same as -3 skin factor case.

Appendix B: Interviews with Industry Experts

KRNACKC081100

A Report to

Research Partnership to Secure Energy for America

for

"Expert Input on IOR Technical Focus Direction and Incentives"

Improved Oil Recovery for Deepwater Gulf of Mexico

Subcontract #07121-1701

Prepared by:

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December 2009

Knowledge Reservoir
Document Control Sheet

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Revision	Date	Reason For Issue	Prepared	Checked	Approved
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0	10/5/09	Second Milestone Report	G. Longmuir	G. Longmuir	
			D. Crossley	D. Crossley	J. Lach

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Project Information: RPSEA Sub-contract #07121-1701

Research Partnership to Secure Energy for America (RPSEA) is a non-profit research consortium with more than 145 members, including 25 US research universities, 5 US national laboratories, other major research institutions, large and small energy producers, and energy consumers. Its mission is to provide a stewardship role in ensuring the focused research, development, and deployment of safe, environmentally-sensitive technology that can effectively deliver hydrocarbons from domestic resources to the citizens of the US.

RPSEA was chosen by the US Department of Energy's National Energy Technology Laboratory to manage a public-benefit research program set up by the US Congress in the Energy Policy Act of 2005, funded from lease bonuses and royalties paid by industry to produce oil and gas on Federal lands. An element of this research program is the identification and development of new methods of exploring for, producing, and transporting-to-market hydrocarbons from deepwater (> 1,000 ft) and ultra-deepwater (> 5,000 ft) Gulf of Mexico.

As part of RPSEA's overall research roadmap for the Gulf of Mexico (GoM), and following competitive bidding, RPSEA awarded sub-contract #07121-1701 to Knowledge Reservoir, LLC of Houston, to investigate Improved Oil Recovery (IOR) processes. Knowledge Reservoir's partners in this effort are Louisiana State University and Anadarko Petroleum.

Most IOR processes are currently not feasible in the challenging environment of deepwater and ultra-deepwater (collectively, DW) GoM. The objectives of sub-contract #07121-1701 are to identify the most prospective IOR processes for the DW GoM; to identify "technology gaps" which are currently preventing the application of those IOR processes; and to identify avenues for future Research and Development which might bridge those technology gaps and make those IOR processes economically viable in DW GoM.

In subsequent work (beyond the scope of this sub-contract), RPSEA may seek appropriate partners and invest funds in Research and Development projects to advance those identified IOR processes to commercial practicality for application in the deep waters of the Gulf of Mexico.

1 Executive Summary

Knowledge Reservoir is pleased to present this Milestone Report to Research Partnership to Secure Energy for America (RPSEA) for consultative services on Improved Oil Recovery processes for deepwater and ultra-deepwater Gulf of Mexico, pursuant to sub-contract #07121-1701.

As part of the sub-contract Scope of Work, Knowledge Reservoir was directed to seek input from experts to help identify and prioritize Improved Oil Recovery (IOR) opportunities in deep water and ultra-deepwater Gulf of Mexico (DW GoM).

The interviews reported here build on earlier workshops organized by the US Department of Energy in 2000 and by RPSEA in 2005. Knowledge Reservoir interviewed 18 carefully selected individuals from industry, government, and academia with relevant widely-varying expertise and with a deliberately broad range of perspectives.

The views of these experts are broadly in line with the major conclusions from the earlier workshops. The principal way to improve ultimate recovery in DW GoM will be to reduce the costs of wells and facilities. Interviewees suggested a broad range of approaches which might help to accomplish this. In general, the experts did not expect to see major breakthroughs; rather, they expected that progress will likely come from the integration of multiple individually-small incremental improvements in many different technologies.

There was less input from the experts on new and improved IOR processes which would increase ultimate recovery. The experts felt that current IOR processes proven onshore can be made to work offshore with innovations in cost-effective equipment and wells. The experts also emphasized the importance of implementation to the success of IOR projects. IOR implementation needs an integrated team, from sub-surface specialists to field operations staff. IOR implementation also needs a well-organized adequate data acquisition program. Any IOR process considered for application offshore should already have a successful track record onshore.

Compared to the prior workshops, the experts in these individual interviews placed more emphasis on risk (and the perception of risk) as key barriers to the implementation of IOR in DW GoM. The ‘high risk’ of offshore was related back to reservoir complexity and the mixed track record of forecasting reservoir performance. There was no consensus on how best to mitigate risks. However, there was agreement on the need for better data acquisition and modeling tools to improve forecasts which would reduce the risks of doing IOR projects.

Input from the interviews has highlighted the challenge that RPSEA faces in selecting where best to invest its Research and Development (R&D) funds. The key areas are cost reductions in wells and facilities, but progress is likely to come from the integration of multiple small advances in many technologies rather than from focused R&D investments in a few selected technologies. No further specific direction was given on IOR processes (waterflooding, gas injection, etc.) which are considered important for the future improvement of oil recovery factor.

2 Background to the Expert Interviews

2.1 *Genesis of the Expert Interviews*

The Scope of Work for Sub-Contract #07121-1701 calls in Section 1.1.a for the facilitation of brainstorm meetings on IOR technical focus direction and incentives:

"KR, LSU and APC shall conduct workshops and other discussion forums with IOR experts to include industry, academic and RPSEA/government personnel to present the team's plans for carrying out the project, solicit ideas, methodologies, concepts and process variations, and to help identify and begin prioritizing key IOR opportunities in the DW GoM."

In the years before the current RPSEA contract, the US Department of Energy sponsored a number of workshops on technology development for deepwater and ultra-deepwater Gulf of Mexico (DW GoM). To build on those efforts, Knowledge Reservoir gained approval from RPSEA's Working Committee to follow up with a series of focused interviews with a limited number of experts on the oil and gas industry.

Experts were carefully selected to encompass a wide range of backgrounds and perspectives. The individuals who participated in the interviews are listed in section "List of Interviewees".

Individual interviews at the interviewee's convenience were hoped to be more efficient and practical to arrange than a workshop requiring simultaneous attendance by all the experts. While individual interviews did make more efficient use of the interviewee's time, the process of organizing and implementing those interviews turned out to be more time-consuming than originally expected. It had also been hoped that the experts might be more forthcoming in individual interviews than in a crowded workshop; this hope does seem to have been fulfilled.

2.2 *US DoE Workshops – 2000*

In 2000, the US Department of Energy held a series of workshops around the US, from which they developed an *"Offshore Technology Roadmap for the Ultra Deepwater Gulf of Mexico"* (US DoE, November 2000). The objectives of those workshops were described thus in the final report:

"Meeting the Nation's growing demand for energy through safe and sustainable deepwater energy development requires a deliberate, coordinated, and well-financed effort - it requires a detailed roadmap.

This report, and the roadmapping exercise that produced it, is the result of a series of transparent workshops held across the nation."

DoE organized a kick-off meeting in Houston followed by a series of 5 Offshore Technology Roadmapping (OSTR) workshops at various locations in the US in July and August 2000. Each workshop focused on a different set of stakeholders – Investors, Producers, Technology, Government, and Non-governmental Organizations. The workshops were attended by a total of 159 generally very senior level individuals from across the spectrum of stakeholders.

A critical point which emerged from these workshops was that no single technology was identified as holding revolutionary potential. Rather, the expectation was that breakthroughs in DW GoM production would come from integrating incremental evolutionary developments in

many different technologies into coherent and well-executed efficient field development processes.

Three major technology themes emerged from the workshops:

- Evolutionary and Revolutionary Technologies
- New Systems Architecture
- First-Time Technology Demonstration

In addition, three related themes were deemed to be very important to the eventual successful implementation of new technology in DW GoM:

- Infrastructure Improvements
- Regulatory Innovations
- Improved Communication and Education

The Ultra-Deepwater Offshore Technology Systems Application Roadmap developed from the inputs to the 2000 DoE Workshop process is included as section “2000 – Roadmap from US DoE Workshops”.

Interestingly, IOR processes *per se* did not feature highly on this roadmap. The perception of participants appears to have been that the challenges in DW GoM lay in being able to implement well-known IOR processes to improve ultimate recovery at an affordable cost, not in identifying new variations of IOR processes.

2.3 *RPSEA Workshop – 2005*

In 2005, RPSEA organized a well-attended Technology Workshop on ultra-deepwater oil and gas, in association with Texas A&M University, University of Houston, and Louisiana State University. The workshop had almost 90 attendees, from operators, contractors, suppliers, universities, and national laboratories (RPSEA, 29 November 2005).

The 2005 workshop developed a list of 22 suggested “Research Thrust” areas, grouped under 5 general headings:

- Environment, Safety, Risk and Training
- Energy to Market
- Rigs, Reach and Ultimate Recovery
- Advanced Reservoir identification and Characterization
- High Intensity Design

The Research Thrust areas from the Final Report on the 2005 workshop are included in section “Research Thrust Areas: 2005 RPSEA Technology Workshop”.

Interestingly, and similar to the 2000 DoE workshops, Improved Oil Recovery processes *per se* again did not attract much attention in RPSEA’s 2005 workshop. The focus once more was primarily on reducing the costs of implementing known IOR processes.

2.4 *Interview Process*

The objective of the expert interviews was to add to what had been concluded from the earlier workshops by exploring the individual views of oil and gas industry experts with a wide range of perspectives. Key topics selected for the interviews were:

- Opportunities for improved oil recovery in deepwater Gulf of Mexico
- Barriers to improved oil recovery in deepwater Gulf of Mexico
- The optimum focus for the RPSEA study

Section 9 lists the 18 individuals interviewed. Section "Briefing Note Provided to Interviewees" is the briefing note provided to each expert ahead of the interview (nominally 30 minutes, in practice up to 2 hours).

To encourage openness and free thinking, experts were requested for their personal assessments rather than the views of an employer or any other organization. They were also assured that, in the report to RPSEA, comments would not be attributed to any identified interviewee.

Each expert was briefed prior to the interview that this study for DW GoM had adopted a very broad definition of the scope of Improved Oil Recovery. For this study, IOR is considered to range all the way from infill drilling and artificial lift to miscible flooding for the recovery of residual oil.

To garner a very broad set of knowledgeable perspectives, the experts interviewed ranged from individuals currently operating offshore developments to retirees. Each individual had past or present involvement in or knowledge of the oil and gas industry, deep water or harsh environment developments, or IOR. Experts had formed their individual assessments about IOR in DW GoM while working in a broad range of capacities over their careers. Some had worked in major oil companies; others had also worked for smaller independent operating companies. Some had experience with service companies and with contractors. Some had gained an overview perspective by working as industry journalists. Some had experience working in government or academia.

3 State of the Art of IOR

3.1 *Goals of Discussion on State of the Art of IOR*

The experts were interviewed on their personal assessments about whether Improved Oil Recovery (IOR) has been successful worldwide, to help Knowledge Reservoir calibrate their individual perspectives. They were also encouraged to discuss their personal experiences with IOR processes. Their general views on offshore IOR were polled. Interviewees were also asked for their views on leading participants in IOR, whether organizations or individuals.

3.2 *IOR Processes Worldwide*

The great majority of the experts felt that, given the broad definition of IOR in this study, those processes have in the aggregate been successful or very successful in application around the world (Figure 1). About 20 % of the experts had either a neutral or "not successful" opinion about overall IOR application.

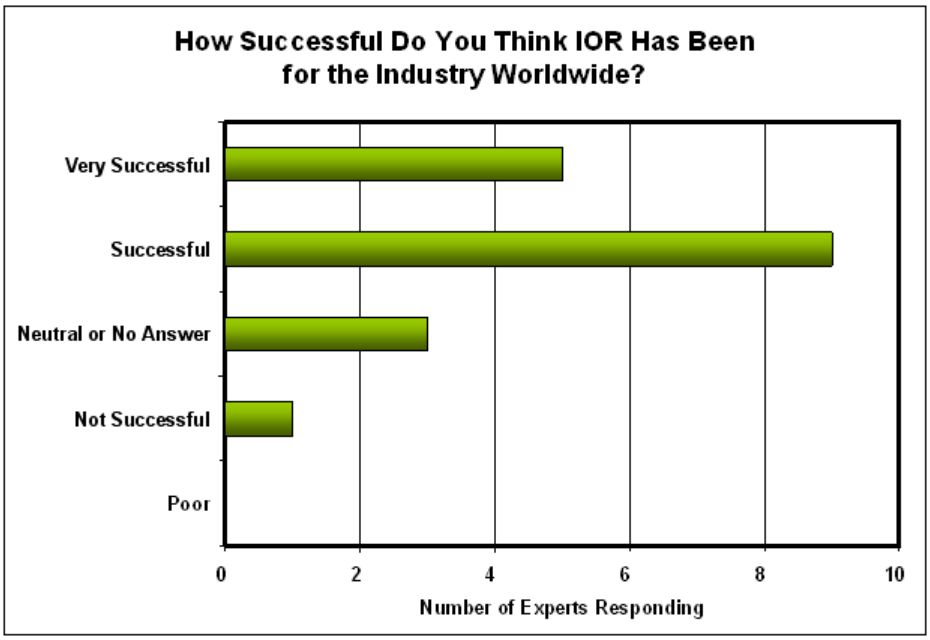

Figure 1: Success of IOR

The more basic IOR processes such as artificial lift and water flooding were almost universally thought to be successful.

The individuals who gave non-positive responses on IOR focused more on the Enhanced Oil Recovery (EOR) end of the IOR spectrum (e.g., miscible recovery of residual oil). Such processes were thought to have been successful only in certain areas and formations. An example would be CO_2 injection: there was wide agreement that CO_2 flooding has been successful in the Mid-Continent US, while it has been relatively unsuccessful in Louisiana and South Texas. Sub-sea wells were generally thought to have been successful in developing smaller discoveries; but debate is not over on the long-discussed question of balancing the

benefits of lower initial costs vs. higher later operational costs and difficulties. Processes related to thermal IOR recovery were generally not thought to be applicable to DW GoM.

One lesson from real world applications mentioned by several experts was that successful IOR is not just a function of the technology; success also depends on how the IOR process is implemented in the field. Successful implementations have been based on a true integrated team approach, from initial reservoir description to IOR field operations.

Success has also been found to be dependent on applying an IOR process to reservoirs appropriate for that process. Having a good reservoir description is a related factor critical to success, and especially having an understanding of reservoir complexity. Many interviewees suggested that an early focus on reservoir description using all available tools is important if IOR processes are later to be implemented successfully.

Where reservoir description was favorable or well-described up front and where conditions have allowed multiple low-cost reservoir penetrations, IOR processes have been generally perceived as having been successful.

3.3 *Economics – Main Driving Force for Decisions*

All the industry experts identified economics as the main driving force in both the initiation and the ultimate success of any application of IOR.

3.4 *Perception of Risk is a Key Hurdle*

The perception of risk was identified as a significant cousin to economics in the dominant factors for IOR success.

The perception of risk plays an important role in final decisions on the implementation of IOR projects. Decision-making is often affected by a "perfect storm" of reservoir complexity and high development costs. Several experts pointed out that companies in effect often include a safety margin for technical and economic risk in project evaluations. Based on their own bitter experiences with project cost overruns and poorer-than-predicted reservoir performance, most companies require a much higher rate of return on proposed developments than they actually achieve from the majority of their projects.

A worldwide trend of growing government involvement and assistance in IOR was noted by many of the experts. A number of the interviewees thought that National Oil Companies have been able to make significant progress in IOR because government assistance has permitted them to take a longer-term strategic approach to technology development. Examples quoted were government assistance for National Oil Companies in China and Norway. This governmental support provides a form of "de-risking", which can make it possible for National Oil Companies to proceed with the implementation of IOR processes which are not initially assured of being technically and economically successful.

Another aspect of the perception of risk is the understandable reluctance of operators to invest large sums of money in IOR processes which have not yet been proven to be effective, particularly in challenging environments such as DW GoM.

The concept of lowering risk (and the perception of risk) was expressed in different ways by many of the experts. In many ways, lowering the perceived risk is directly tied to lowering IOR project costs, which results in improvements to project economics.

3.5 *Leaders in IOR Technology*

Significantly, the experts did not identify any clear leader in IOR technology.

To some extent, this reflects the breadth of the topic, with different companies and organizations having different areas of focus. It may also reflect the severe cut-backs in Research departments at major oil companies over the last few decades. Service companies have increased their Research and Development (R&D) spending to currently substantial levels, but their objectives are somewhat different from operators.

Several interviewees thought that National Oil Companies have now taken the lead in the development of IOR.

4 Adapting IOR to DW GoM

4.1 *Goals of Discussion on Adapting IOR to DW GoM*

Experts were interviewed to explore individual views related to how to improve recovery from typical DW GoM reservoirs, which tend to be deep and to have significant reservoir complexity. The fact that relatively few DW GoM reservoirs have been water-flooded was discussed, and reasons were explored for the relatively sparse application in DW GoM of this well known and widely used IOR technique. The possibilities for gas injection – hydrocarbon gas, CO_2, N_2, air – were discussed, as were the challenges of optimizing recovery using sub-sea completions. An attempt was made to identify any Local Favorable Factors for IOR specific to DW GoM.

4.2 *Cost is King*

One of the most often-mentioned ways to improve recovery from DW GoM reservoirs was to lower well costs by developing innovative improvements in well drilling. This in turn would increase the number of reservoir penetrations which would be economically feasible in the complex reservoirs of DW GoM, and would consequently increase ultimate recovery. Similarly, there was a lot of focus on the need to lower the costs of production facilities.

There were quite a few suggestions that industry needs to rethink development options in DW GoM, especially to provide ways to develop smaller fields profitably. In simple terms, the industry needs the ability to drill lower cost wells and to build less expensive producing facilities that will not be burdened with excessive future operating costs. Specific areas of facility design that should be targeted are reducing platform weight and space requirements for IOR facilities, and lowering the costs of sub-sea wells and facilities.

Associated with the goal of reducing well costs, several experts suggested that “huff ‘n puff” (cyclic production/injection) processes should be considered as a way to reduce the need for additional wells when implementing injection processes. Certain reservoir conditions such as steeply-dipping reservoirs trapped against salt or other geological trapping features could represent a sub-set of potentially profitable opportunities for recovering additional oil by cyclic IOR injection processes, e.g., by sweeping attic oil.

4.3 *Addressing Reservoir Complexity*

The need for more reservoir penetrations is directly related to reservoir complexity, which leaves some portions of reservoirs undrained and results in poor sweep efficiency when an IOR injection process is implemented on a wide well spacing. An associated issue is well placement within complex reservoirs – profitability could be improved by better reservoir description at an early stage of field development, which would allow the original wells to be drilled in the optimum locations for sweeping the reservoir and thereby reduce the costs required later for additional or sidetracked wells.

An area for improvement mentioned by several experts was the need to better define the variable permeability seen in certain DW GoM formations – especially in the relatively unexplored Paleogene reservoirs. There was seen to be a need for good data acquisition and extensive monitoring of wells, and for the ability to manage zones within wells to target those parts of reservoirs which are more likely to be economically productive for IOR.

Some interviewees suggested a radically different approach to dealing with reservoir complexity. Instead of trying to understand reservoir complexity before making development decisions, they suggested it would be more realistic to plan on picking the low-hanging fruit in "Earn As You Learn" developments. This approach would depend on very low cost production facilities (e.g. tie-backs to existing facilities) or moveable production facilities. The aim is to get discovery and appraisal wells onto production quickly, and then drill additional wells in the best portions of the reservoir if production performance shows this is likely to be economic.

4.4 *Lessons from Onshore*

Another theme was the important lessons that could be learned from prior applications of IOR processes in onshore environments.

Several industry experts mentioned that a logical progression would be to start with IOR processes that have already been proven successful onshore and develop them for eventual application offshore in deep water. A challenge with this approach is the need to reduce the very high costs of drilling and development in the DW GoM, which are much greater than onshore. Nevertheless, a track record of successful application of an IOR process onshore is likely to be a necessary (but insufficient) condition for its eventual successful application offshore.

4.5 *Need for Successful Prototypes*

There were several suggestions that a real impetus for investment in IOR in DW GoM would be successful prototypes showing that particular IOR processes were economically successful in the unique conditions of DW GoM.

The perception of several experts is that, given the high technical risks and generally marginal economics, many companies are waiting to see a success before making serious commitments to IOR in DW GoM. Many potential participants in DW GoM are thought to have adopted a "fast follower" approach. These companies are not likely to implement IOR technology offshore until their perception of risk has been reduced by seeing some other operator achieve an economic success with the same process.

4.6 *Local Favorable Factors for IOR in DW GoM*

Knowledge Reservoir's prior evaluation of IOR projects worldwide indicated that successful implementation of a specific IOR process was often related to the existence of Local Favorable Factors. Clearly, the reservoir rock and fluid characteristics have to be suitable for the particular IOR process under consideration. In addition, other factors specific to that particular location seem to have been important in successful real-world applications of IOR processes.

One example is the very large miscible hydrocarbon gas flood EOR process implemented over several decades at the Intisar D carbonate reef field in Libya. While the geology of the reef field favored a gravity-stabilized gas flood and the characteristics of the oil made miscible flooding possible, the key Local Favorable Factor was the availability of zero-cost injection gas by using surplus associated gas from a neighboring field.

Similarly, gas injection IOR processes in the early years of the North Sea were driven by the Local Favorable Factors of the lack of an adequate market for produced gas and governmental requirements to conserve associated gas for later sale. As the market for gas grew in Europe, associated gas was sold and gas injection IOR projects declined.

Another example is the world's largest chemical flood in China's Daqing field. In addition to favorable reservoir characteristics, the Local Favorable Factor here was the strategic decision by Chinese authorities to continue investing, despite initial disappointments, in research and pilot testing until a chemical formulation that worked was developed; and then to commit to manufacturing the chemicals at the field to reduce the delivered cost.

Given this background, the views of the experts were sought on any aspects of the DW GoM that might potentially become Local Favorable Factors (Figure 2).

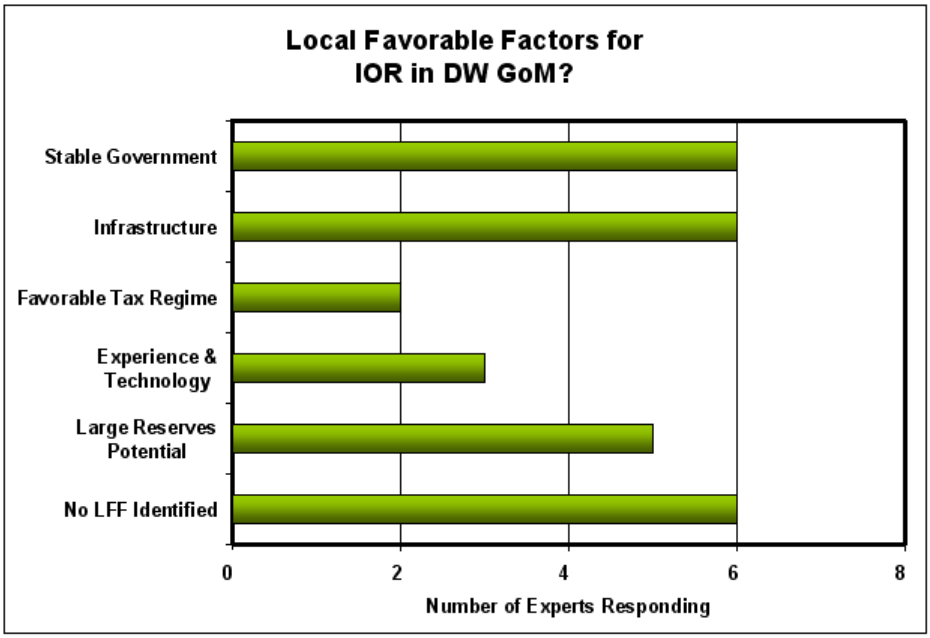

Figure 2: Local Favorable Factors for IOR in DW GoM

One of the most often mentioned potential Local Favorable Factors for DW GoM development was government stability. This may be a reflection of many of the experts having experience in other oil-producing countries where government stability cannot be taken for granted, and where contracts may not be strictly honored. Several of the interviewees also mentioned that the tax situation in the US has historically been relatively favorable compared to some other countries around the world. The leasing environment in DW GoM is one of relatively few around the world which allows the investor to participate in the upside potential of higher oil prices, albeit at the cost of exposure to the downside risk of lower oil prices.

Equally mentioned as a potential Local Favorable Factor, was the good oil and gas infrastructure adjacent to DW GoM. This infrastructure provides obvious benefits in terms of connection to onshore markets which can absorb any conceivable level of production from DW GoM. It also has the benefit of providing near-by technological expertise from Shelf, inland waters, and land-based operations.

The relatively large reserve potential in DW GoM compared to onshore, inland water, and GoM Shelf opportunities, was often mentioned as a Local Favorable Factor.

5 Looking Forward

5.1 *Goals of Discussion on Looking Forward*

In the Looking Forward discussions with the experts, there was an attempt to identify what they felt were the biggest hurdles to actual implementation of IOR in DW GoM. Policy changes that could possibly assist in implementation of IOR in DW GoM were discussed. And finally, the bottom-line question was explored regarding the experts' opinion on the potential for actual IOR development in DW GoM within a reasonable time frame.

There was keen interest in any technological advances the experts envisioned that could be real "game-changers". Because of their importance to the focus of RPSEA's IOR project, potential game-changers are addressed separately in the next section of this Milestone Report.

5.2 *Specific Hurdles and Potential Policy Changes for IOR*

The experts identified a fairly wide range of hurdles which are barriers to profitable development of IOR in DW GoM.

Some experts suggested that lease terms for DW GoM should be altered to encourage lease holders to maximize oil recovery, either through economic incentives or through mandates to implement IOR. The latter process was apparently used to good effect in the early years of the North Sea, albeit in an environment where field sizes were typically an order of magnitude larger than in DW GoM and unit development costs were more modest. Some interviewees were concerned that any effort to mandate IOR would actually reduce ultimate recovery by forcing operators to walk away from marginal discoveries.

Once again, high costs were very widely mentioned as the most significant hurdle to development. The combination of high well costs and compartmentalized reservoirs (which require more reservoir penetrations for effective development) was widely thought to be a very serious hurdle to IOR in DW GoM. Lower drilling and completion costs and reduced production facilities costs are felt to be desperately needed. Platform weight, space, and cost requirements for IOR-related equipment such as pumps, compressors, and water treatment were thought to be a particular obstacle to IOR. Scalable facilities (i.e., ones whose costs are proportional to reserves) are needed to develop the many smaller fields in DW GoM.

Since IOR processes typically do not have strongly robust economics, unpredictable and continually-changing oil and gas prices have historically been a major hurdle to implementation of IOR. It is difficult to plan for IOR processes when product prices shift dramatically on a time scale much shorter than that for development. Some experts wondered if it might make more sense for operators to plan cheaper developments which intentionally produce fields at lower rates, to "hedge" the impact of varying future oil and gas prices.

Several experts mentioned the industry's history of underestimating future difficulties as a hurdle to getting leaseholders to commit to IOR developments in DW GOM. Those poor estimates may in part have resulted from historic tendencies to control costs by cutting back on the acquisition of reservoir data, which militated against effective reservoir management and resulted in unpleasant surprises.

Some experts perceived that government agencies, such as Minerals Management Service (MMS), could be a hurdle. Agencies have not always effectively promoted the application of

new technology. In some cases, MMS has not approved innovative proposals to increase recovery in a timely fashion. In contrast, other experts suspect that some industry participants may at times use the MMS as a convenient excuse for not moving ahead when the real concern is underlying project risks and economics.

The lack of US government support and financial incentives for IOR compared to certain other countries was also listed as a possible policy hurdle.

5.3 *Future IOR Expectations*

Short-term future expectations from industry experts for IOR in DW GoM within the next 5 years fell fairly narrowly into two bands - very little development, and moderate development. The results were about evenly split between the eighteen experts interviewed. In general, expectations seem to be fairly low (Figure 3).

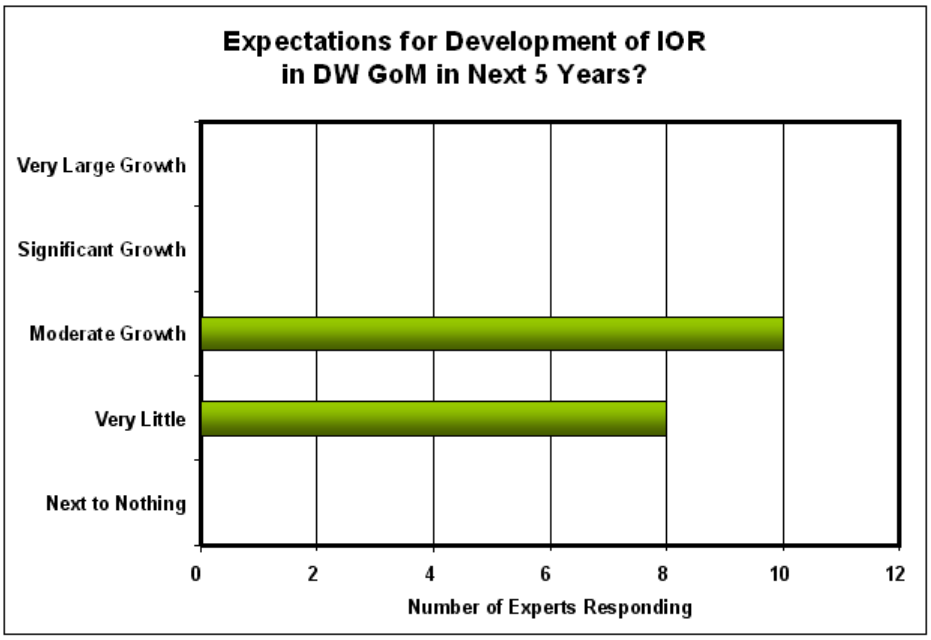

Figure 3: Future (+/- 5 year time frame) IOR expectations in DW GoM

One possible path to the ultimate implementation of economically-viable IOR projects would be a series of technological "baby steps", i.e. modest improvements to existing technology.

The current success of shale gas production in onshore US was mentioned as an example. This IOR success was not a "new" technology. Rather, it was the result of incremental process improvements to an existing technology – hydraulic fracturing – applied to previously uneconomic formations in areas known to contain large in place volumes of gas.

In the longer term, there are possibilities for a number of “game-changers”. These are the subject of the following section.

6 Game-changing Technologies

6.1 *Reduction in Risk*

A consistent theme in the input from the experts was that risk (both real and perceived) is a major barrier to the implementation of Improved Oil Recovery in deepwater Gulf of Mexico. While there was broad consensus on the importance of reducing risk, there was a very wide spectrum of views on what game-changers might accomplish this.

Greater government involvement, through tax breaks and subsidies, was seen by some as important to help mitigate the high costs of potential technical failures in the implementation of IOR processes. Others saw reduced government involvement as a key way to lower perceived risks, by eliminating the uncertainties created by unpredictable politically-driven changes in tax and regulatory policies, by shortening regulatory delays in project cycle time, and by preventing political priorities from distorting the direction of technology development.

There were also distinctly opposing views about how to address the substantial risks associated with the inevitably imperfect understanding of the complex reservoirs found in DW GoM. One approach is to improve reservoir understanding before committing to expensive developments. Improved understanding can come through investments in extensive seismic data acquisition and processing, appraisal drilling, pressure monitoring in abandoned well bores, and detailed studies – all of which increase sunk costs. An alternative approach is to live with reservoir uncertainty and focus instead on minimizing sunk costs – do tie-back developments, or phased developments, or build facilities which can be moved to another field if the production performance of the first field is disappointing.

A factor which was repeatedly mentioned was that a successful demonstration of IOR technology would result in a large reduction in perceived risk. However, most operators would prefer to see that technology demonstration at someone else's field. Many of the players in DW GoM have consciously adopted a "fast follower" model, where they intend to let some other company take the initial risk of proving that a particular IOR technology will work. Consequently, few companies are prepared to take the risk of being "first mover".

Another factor in the high perceived risks with IOR in DW GoM is concerns about the reliability of performance predictions, despite the intense efforts the industry puts into data acquisition, statistical geo-modeling, and reservoir simulation. Arguably, decision-makers have reacted to this perceived unreliability in performance predictions by investing only in projects which are predicted to be strongly economic even when assessed against stringent thresholds. Many IOR processes cannot meet this economic hurdle.

Potentially game-changing studies are in progress which could alter the industry paradigm on how to make useful and reliable performance predictions. One alternative approach under consideration would step back from the present-day use of very large, complex reservoir models and instead focus on consciously-simplified surrogate models which are tailored to address a specific development decision. An example might be the use of a stylized single-well simulation model instead of a Full Field Model to decide optimum reservoir completion practices. If successful, an approach like this could lower the perceived risk of investing in IOR processes.

6.2 *Reduction in Well Costs*

In contrast to the diverging views on government involvement and handling reservoir uncertainty, there was universal agreement that a major game-changer would be to reduce the very high costs of wells (and well interventions) in DW GoM.

Industry has successfully developed complex compartmentalized reservoirs onshore through intensive drilling. Such tight well spacing is never going to be economically feasible in DW GoM, but the ability to provide lower cost reservoir penetrations would certainly result in higher ultimate recoveries. A number of potentially game-changing technologies were mentioned.

Dual gradient drilling, where the return mud flow is pumped from the sea floor back up to the rig floor, holds great promise for avoiding the problems with excessive overbalance that currently result in the need for multiple additional protective casing strings in DW wells, driving up non-productive time and increasing well costs.

Sea floor drilling, where the drilling rig itself is placed on the sea floor, would achieve the same benefits as dual gradient drilling. Sea floor drilling would also have extensive application in difficult-to-access marine areas outside the DW GoM, such as under ice. A fully automated, modularized sea floor drilling rig with a self-contained power source is conceivable, but the technology to implement it fully is obviously far in the future.

Nearer-term, appropriate application of monobore technology using expandable tubulars could reduce well costs.

Other game-changing technologies to reduce the cost of reservoir penetrations could include perfecting multi-lateral spider wells, and developing methods to drill low cost sidetracks as the production from existing reservoir penetrations decline. The ability to complete multiple zones in a single trip would also reduce well costs substantially.

It will also be important to reduce the costs of well remediation, e.g., by expanding industry's capabilities for riserless well interventions.

6.3 *Reduction in Facility Costs*

There was also consensus among the experts that lowering the costs of production facilities would result in higher ultimate recoveries from DW GoM fields. Experts mentioned a number of potential game-changers.

Subsea processing is advancing rapidly. There are already installations with sea floor multiphase pumps (MPP) and sea floor separator/pump systems. There is growing interest in sea floor water injection equipment. The cost advantage comes from reducing the weight and space required for facilities on a surface platform, thereby reducing the costs of the floater. This saving will be offset to some extent by the higher cost of equipment designed to run remotely on the sea floor, and by the potentially much higher costs of maintenance. To remove the need for the floater altogether, a sea floor mounted power source would ultimately be required – such as a modular miniaturized nuclear power plant.

Much of the Original Oil in Place in DW GoM fields is in reservoirs which are individually small – 40 Million Bbl OOIP or less. Many discovered reservoirs are left undeveloped because they cannot support the necessary facility costs. The minimum cost of stand-alone development seems to be around $1.5-2.0 Billion. A game-changer would be truly scalable facility costs, where small fields could be developed at proportionately low costs.

A related game-changer would be low-cost modular water injection facilities, which could be retro-fitted to existing production floaters, using whatever limited space and load-carrying capacity is available.

Another game-changing approach would be the construction of shared floating facilities for production and/or injection. The concept would be to have facilities mounted on vessels which would rotate among a number of fields, each of which is too small individually to support the costs of such facilities. The vessels could be owned cooperatively by a group of operators, or could be leased from third-party suppliers.

Another potential approach to lowering the costs of IOR processes would be the development of closed loop systems, which would separate and re-inject produced fluids with minimal treatment.

There are potentially exciting advances in developing low cost umbilicals, in which large expensive copper cables would be replaced with much more conductive carbon nanotubes.

There could be value in revisiting some older technologies, such as Through Flow Line (TFL) tools. TFL was the focus of a lot of research interest some decades ago, but was overtaken by advances in other technologies. Perhaps a TFL Electric Submersible Pump could solve the problem of replacing those pumps economically in a sub-sea environment.

6.4 *Other Potential Game-changers*

Experts mentioned other potential new technologies which could improve the economics of IOR in DW GoM.

To deal with High Pressure/High Temperature (HP/HT) reservoir conditions in many DW GoM reservoirs, there is a need for HP/HT-ready equipment – logging tools, fluid sampling tools, perforating guns, laboratory test equipment. Because of those same reservoir conditions, there is a need for polymers stable at high temperatures if polymer-enhanced water-flooding is ever going to become feasible in DW GoM fields. To deal with the high reservoir pressures, there is a need for affordable ultra-high pressure gas injection equipment – compressors, flow lines, wellheads.

There are high hopes for nanotechnology. While the technology is still in a very early phase of development, there is the possibility that nanotechnology might eventually yield stronger materials, or adaptable diversion agents to improve sweep efficiency of injected fluids, or even tools to modify the bulk properties of the reservoir itself.

7 Observations on the Experts' Input

It is interesting that the main areas the experts focused on were reductions in costs and risks, not increases in incremental recovery from new or modified Improved Oil Recovery processes. Notably, the experts' focus on the importance of reducing costs was in line with the general conclusions from the DoE's 2000 workshops and RPSEA's 2005 workshop. This may reflect a common understanding that the reservoir approaches to maximizing oil recovery are already well understood.

The experts tended to focus expectations on continued progress in improving ultimate recoveries through a series of individually-small incremental advances and through the consolidation of existing separate technologies. One example mentioned was the development of top-drive drilling, which has substantially improved the industry's capability to drill challenging wells economically. There was no "Eureka!" moment in the development of top-drive drilling – it was the result of the patient accumulation and integration of many separate individually-modest incremental technological advances. This theme from the interviews is in line with the consensus at the earlier workshops.

The current individual interviews put more emphasis on the issue of risk (and the perception of risk) than the earlier workshops. It is also very interesting that a number of the experts have concluded that the productive approach to dealing with the issue of reservoir complexity is to redefine the problem. In the view of some individuals who have worked long and hard to maximize economic recovery from DW GoM fields, it is more productive to change the approach to development than to try to understand reservoir complexity.

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Rustom Mody, VP Technology, Baker Hughes, August 28, 2009.

Presentation at 13th Annual Gulf of Mexico Deepwater Technical Symposium, New Orleans, LA

9 List of Interviewees

1. Ken Arnold, President, K. Arnold Consulting Inc., Houston, TX
2. Walt Bozeman, Team Leader, Gulf of Mexico Exploration Engineering, BP, Houston, TX
3. Ed Capen, Consultant, Durango, CO
4. Jim Chitwood, Technology Manager, Ultra-Deepwater, Research Partnership to Secure Energy for America, Sugar Land, TX
5. Bo Cribbs, Reservoir Engineer – Tahiti Project, Chevron Exploration and Production Company, Houston, TX
6. Jerry Hardouin, Consultant-Manager, Reservoir Asset Management, Chevron Global Upstream, Houston, TX
7. Jerry Horne, Senior Staff Reservoir Engineer, Anadarko Petroleum Corporation, The Woodlands, TX
8. David Kihneman, Reservoir Engineer – Africa Group, Anadarko Petroleum Corporation, The Woodlands, TX
9. Larry W. Lake, Professor, Petroleum and Geosystems Engineering, University of Texas at Austin
10. Blane McGlawn, Production Team Leader – Azurite Project, Murphy West Africa, Pointe Noire, Republic of the Congo
11. Guntis Moritis, Production Editor, Oil and Gas Journal, Houston, TX
12. Gene Narahara, Senior Reservoir Engineering Advisor, Chevron Energy Technology Company, Houston, TX
13. William Pike, Senior Associate, Technology and Management Services, Inc., Sugar Land, TX
14. John E. Ritter, Senior Director of Worldwide Reserves and Reservoir Engineering Occidental Petroleum, Houston, TX
15. Art J. Schroeder, Jr., Manager, Deepwater Technology and Commercialization, Research Partnership to Secure Energy for America, Sugar Land, TX
16. James Sheng, Senior Reservoir Engineer, Total Exploration and Production, Houston, TX
17. Robert Shivers, Vice President – Projects, ATP Oil and Gas Corporation, Houston, TX
18. Jeff Sieler, Manager – Technical, Shell IEP-SDS, Bellaire TX

10 Briefing Note Provided to Interviewees

Research Partnership to Secure Energy for America
Deepwater Gulf of Mexico Improved Oil Recovery Project

Sub-Contractor to RPSEA for Project #1701:

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RPSEA Project 1701:

RPSEA is a non-profit consortium with more than 145 members including 25 of the premier research universities in the United States, five US national laboratories, other major research institutions, large and small energy producers, and energy consumers. Its mission is to provide a stewardship role in ensuring the focused research, development and deployment of safe, environmentally sensitive technology that can effectively deliver hydrocarbons from domestic resources to the citizens of the United States.

RPSEA was chosen to manage a public-benefit research program set up by the US Congress in the Energy Policy Act of 2005, funded from lease bonuses and royalties paid by industry to produce oil and gas on Federal lands. An element of this research program is the identification and development of new methods of exploring for, producing, and transporting-to-market hydrocarbons from deepwater Gulf of Mexico.

Following competitive bidding, RPSEA awarded contract #1701 to Knowledge Reservoir with academic partner Louisiana State University and industry partner Anadarko Petroleum Company. The project is targeted at guiding future Research & Development, by identifying those Improved Oil Recovery processes where technological breakthroughs have the potential to add substantial volumes of economic incremental oil from deepwater Gulf of Mexico fields.

Objectives of Interview:

Learn from the individual views of industry experts on:
(1) Opportunities for improved oil recovery in deepwater Gulf of Mexico
(2) Barriers to improved oil recovery in deepwater Gulf of Mexico
(3) The optimum focus for the RPSEA study

Ground Rules:

- Comments should reflect an individual's personal assessment rather than the position of an organization. In the report to RPSEA, comments will not be attributed to any identified interviewee.
- Scope of IOR considered for DW GoM in this project is very broad – infill drilling to miscible flooding.

RPSEA 1701 – Expert Interviews Knowledge Reservoir - 2009

Research Partnership to Secure Energy for America
Deepwater Gulf of Mexico Improved Oil Recovery Project

Interview Topics

Views on the State-of-the-Art of Improved Oil Recovery Worldwide:

- How successful do you think IOR has been for the industry worldwide?
- Observations on particular processes/fields you have been involved in?
- Observations on application of IOR offshore?
- Who do you think are currently the most significant participants in IOR? (Operating companies, service companies, academia, individuals)

Views on Adapting IOR to Deep Water Gulf of Mexico:

- How to improve recovery from typical DW GoM reservoirs (small, deep)?
- Why have relatively few DW GoM fields been water-flooded?
- Practicality of gas injection in DW GoM – hydrocarbon, CO2, N2, air?
- Observations on challenges in optimizing recovery using subsea completions?
- Any favorable factors for IOR specific to DW GoM?

Looking Forward:

- What do you see as the biggest hurdles to DW GoM IOR? (Technological as well as economic)
- Any technological advances that could be real game-changers?
- Any policy changes that could facilitate implementation of IOR?
- How would you expect to see IOR develop in DW GoM?
- Any other thoughts or observations?

RPSEA 1701 – Expert Interviews Knowledge Reservoir - 2009

11 2000 – Roadmap from US DoE Workshops

Roadmap developed in US DoE's 2000 series of Offshore Technology Roadmap workshops:

		2001	2002	2003	2004	2005	2006
High Intensity Design	New Systems Architecture	Definition, Evaluation, and Concept Selection ▼◆▲○+●○■❑	Develop Interface Definition & System Level Decision Rules ▼◆▲○+●○■❑	Publish Open Architecture Definition ▼◆▲○+●○■❑			
	High Intensity Design Engine	Conceptual Flow Sheets & Fast Productivity Index ▼+❑	Software to Host System Configuration ▼+❑	Develop System Optimization Computational Mathematics & Hardware ▼+❑	Comprehensive Virtual System Optimization & Visualization Prototype ▼+❑	Pilot Application for Specific Ultra-Deepwater Field Development ▼+❑	
	Component Optimization Modules	Critical Components Identification ▼	Virtual Component Module Prototype for 3 Core Subsystems ▼◆▲●❑	Virtual Component Module Prototype for 3 Additional Core Subsystems ▼○+○	Virtual Component Module Prototype for 3 Additional Subsystems ▼■✳	Virtual Component Module Prototype for 3 Additional Subsystems ✳▼○	
Accelerated Reservoir Exploitation	Reservoir Property Verification		Low Cost Micro Drilling Self Contained Fluid/Rock Sample Retrieval System ▲●○◆	Alternative Subsalt Remote Sensing & Imaging Technology ◆▲✳	Final Reservoir Exploitation Design ▼◆▲●✳		
	Subsea Gathering Systems	Systems Definition and Early Design ▼◆▲●○	Low Volume System Lab & Field Trials ▼◆▲●○	High Capacity System Design and Component Testing ▼◆▲●○	Offshore Shelf Well Field Trials ▼◆▲●○	Ultra-Deepwater Field Trials ▼◆▲●○	
	Reservoir Monitoring and Control	Systems Definition and Early Design ▼◆▲	Low Volume System Lab & Field Trials Plus Seismic Fluid Movement Monitoring ▼◆▲	High Capacity System Design and Component Testing with Adjustable Learning Completion Capability ▼◆▲○	Offshore Shelf Well Field Trials ▼◆▲	Ultra-Deepwater Field Trials ▼◆▲	
Rigs/Reach/Riserless	Riserless Drilling Systems	Conceptual Engineering and System Architecture ◆▲○●○	Critical Component Development and Testing ◆▲○●○	System Integration and Alpha Testing ◆▲○●○	Shallow Water Trials ◆▲○●○	Deepwater Trials ◆▲○●○	
	System Integration While Drilling	System Concept Development Plus Materials & Placement Research ◆▲○●○	System Architecture Definition & Component Design/Testing ◆▲○●○	System Integration and Alpha Testing ◆▲○●○	Field Trials ◆▲○●○		
	High Capacity Production Wells		System Architecture ◆▲●○	Critical Component Design & Testing ◆▲●○	Field Trials ◆▲●○		
	Intervention Systems	Conceptual Engineering & System Architecture ▼◆▲●	Remote Controlled Light Duty Intervention Robot ▼◆▲●	AUV Service Vessel Intervention Delivery ▼◆▲●	Remote Controlled Micro-Drilling and Workover ▼◆▲●	Fracturing and Cementing AUVs ▼◆▲●	First Time Field Demonstrations ▼◆▲●
Energy to Market	Subsea Processing & Flow Assurance	Acoustic Liquefaction, Membrane Separation, & Hydrate Formation/ Transport Research ◆▲○+■❑	Subsea Processing Architecture & Interface Definition ◆▲○+■❑	Critical Component Design & Testing ◆▲○+■❑	System Integration & Testing ◆▲○+■❑	Offshore Shelf Well Field Trails ◆▲○+■❑	Ultra-Deepwater Field Trials ◆▲○+■❑
	Hydrocarbons to Clean Fuel, Feedstock, Products	Research Interface with Clean Fuels Roadmap +■❑◆	Conceptual Engineering & System Architecture +■❑◆	Critical Component Development and Testing +■❑◆	System Integration & Testing +■❑◆	Offshore Shelf Well Field Trails +■❑◆	Ultra-Deepwater Field Trials +■❑◆
	Offshore Power Generation/Transmission	Superconducting Electric Transmission Pipeline Research +✱◆	Superconducting Electric Transmission Pipeline Research +✱◆	Conceptual Engineering & System Architecture +✱◆	Critical Component Development and Testing +✱◆	Critical Component Development and Testing +✱◆	System Integration & Alpha Testing +✱◆
Environmental Management	Greenhouse Gas Sequestration	See Greenhouse Gas Sequestration Roadmap					
	Well Control with Near Zero Spill Volume	Sensor Research for Early Detection of Loss of Well Control ▲○■	System Development for Point-of-Loss Fluid Capture ▲○■	Detailed Design and Model Testing ▲○■	Prototype System Testing ▲○■	Offshore Shelf Well Field Trials ▲○■	Ultra-Deepwater Field Trials ▲○■

12 Research Thrust Areas: 2005 RPSEA Technology Workshop

Suggested Research Thrust Areas from RPSEA's Utra-Deepwater Technology Workshop held at Houston Hilton Post Oak, October 21, 2005 (from Final Report dated November 29, 2005).

Workshop Objective:

"The objective of this report is to present a joint or collective view from industry, academia, and government regarding the technology challenges and gaps which must be addressed to enable more ultra-deepwater oil and natural gas resources to be developed economically."

Workshop Conclusions:

Table 1: Suggested Research Thrust Areas

Environment, Safety, Risk, and Training
System test labs
Risk reduction and technology adoption
Environmental data
Training during the big crew change
Energy to Market
Flexible / adaptable production systems
Novel riser designs
Gas conversion to fluid processes for marine environment
Early production systems for ultra-deepwater
Flow assurance processes for remote locations
Rigs, Reach, and Ultimate Recovery
Sensor networks for marine environment
equipment health monitoring
Reservoir gathering systems
Ultra-deepwater station keeping
Pore pressure / fracture gradient challenge
Low cost well intervention
Well test design and interpretation
Geohazards assessment and mitigation
Advanced Reservoir Identification and Characterization
Subsalt Seismic
Hybridized Remote Characterization
G&G Integration
High Intensity Design
System Architectural Framework
Integrating Design Engine & Functional Models
Technology Value Landscape

Appendix C: LSU Report on Worldwide IOR Analogs

Literature Review of Selected IOR Processes for GOM Deepwater Application

Milestone Report
May 2010

LSU – Knowledge Reservoir Contract (under RPSEA 07121-1701)
Deepwater IOR: Phase 1

Work Performed Under LSU Research Agreement Number 33399

by

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RPSEA Project 07121 – 1701 Summary Information

Project Abstract

This project is titled Development of a Research Report and Characterization Database of Deepwater and Ultra-Deepwater Assets in the Gulf of Mexico, including Technical Focus Direction, Incentives, Needs Assessment Analysis and Concepts Identification for Improved Recovery (IOR) Techniques. The project will be led and directed by Knowledge Reservoir LLC (KR), with primary project participants Louisiana State University (LSU), Anadarko Petroleum Corporation (APC). Additional participants are Schlumberger, Core Laboratories and CMG.

The project will identify improved recovery opportunities in the early stages of field development planning, such that facility and well designs can be optimized to take advantage of those opportunities. Additionally, opportunities for improved recovery in producing fields will be assessed, as will current and near-future technologies for improved recovery. The project will include characterization of deepwater and ultra-deepwater reservoir assets and compile and categorize key causes of trapped and remaining hydrocarbons in such reservoirs. The prioritization of technology gaps in improved recovery methods will also be addressed as specifically related to deepwater and ultra-deepwater reservoirs, with the aim of identifying leading concepts for future research, investment, development, testing and deployment/application. A thorough and comprehensive review of IOR/EOR techniques and experiences, both on- and offshore, will be conducted. Project results will be captured in a knowledge base to facilitate effective technology transfer. The primary outcomes of the project will be advancement of understanding of improved recovery techniques, provision of a foundation for future development, testing and deployment phases of new technology and methodology, ultimately leading to the recovery of more resources from deepwater and ultra-deepwater assets.

Objectives

The objective of this project is the identification and understanding of IOR opportunities in the early stages of GOM field development planning, such that facility and well designs can be optimized to take advantage of those opportunities. The project will include:

- Characterization of deepwater and ultra-deepwater assets.

- Compilation and categorization of key causes of trapped/remaining hydrocarbons in deepwater and ultra-deepwater reservoirs.
- Prioritization of technology gaps in improving recoveries specifically in deepwater and ultra-deepwater reservoirs and surfacing of leading concepts for closing those gaps.

This project will study improved recovery methods and opportunities for optimizing ultimate recoverability of reserves by impacting field surface and subsurface infrastructure design in the early stages of field development. The project will aim to prioritize technology gaps in improving recoveries specifically in deepwater and ultra-deepwater reservoirs, and to surface leading concepts for closing those technology gaps.

The work will include:

- Investigation / review with a compilation of reports on DW and UDW reservoirs by category, reserves, and recovery factor, including baseline recoveries for current developments, estimates of additional resource potential, including marginally economic fields; current research focus and direction;
- Development of a knowledge base of characterization of causes for trapped / remaining hydrocarbons including estimated trapped resource volumes;
- Prioritization of technical gaps for applying successful IOR techniques;
- A report of recommended future work to close those gaps including the most promising concepts.

This project is designed to deliver a knowledge base capturing the above listed research in a web portal, easily navigable interface, which will enable users to leverage the study results, together with captured public domain information and independent analysis of every DW and UDW field in the GOM.

Executive Summary

This report summarizes the literature review of selected IOR processes for possible application in deepwater Gulf of Mexico (GOM) reservoirs. The main objective is to compile a comprehensive report on IOR processes and identify key concepts, mechanisms and processes that may be applicable to deepwater offshore reservoirs.

The candidate processes were narrowed down from a starting total of over 60 processes after an in-depth screening assessment. Table I is a comprehensive list of the initially selected IOR processes. The assessment was mainly qualitative and based on continuous dialogue with research partners and industry professionals. The selected processes were considered suitable for compact application and/or had some favorable operational economic considerations for the deepwater Gulf of Mexico application.

The six IOR processes that are described in this report in detail are:

- Dump flooding;
- Subsea waterflooding;
- Cyclic waterflooding;
- Hydrocarbon gas injection;
- Air injection/low temperature oxidation;
- Cyclic single-well gas injection/production.

Although the successful implementation of dump flooding hinges on the presence of a strong aquifer or high pressure gas reservoir closer to an oil producing reservoir, the abnormally pressured GOM reservoirs containing low bubble point oil may present some opportunities.

Subsea water injection has been implemented in the North Sea and offshore Brazil and has many benefits, such as increasing the oil production by removing the water from the production stream for re-injection, even though there are many operational issues as well due to the relative limited experience with the newly developed technology.

There are no documented offshore applications of cyclic water flooding but it has been successfully implemented in onshore heterogeneous sandstone and carbonate reservoirs with reported incremental recoveries up to 25% STOOIP.

Cyclic gas injection for the recovery of light oil has so far been only been implemented in onshore sandstone reservoirs with numerous field trials in Louisiana, Texas and Kentucky. On

average, the successful implementation of huff 'n' puff in the field has recovered 10,000 barrels of incremental oil.

Hydrocarbon gas injection has a long history of offshore application in the North Sea, but has mostly been injected as a means of enhancing waterflooding. Reported incremental recoveries were in the range of 1.4 to 3.3 %STOOIP for miscible gas injection projects. Unlike in the North Sea its application in offshore Abu Dhabi reservoirs has been purely as part of an EOR program from the start. Even though the aforementioned reservoirs were carbonate reservoirs, the injection of hydrocarbon gas was able to recover 2% incremental oil on average.

Offshore application of air injection has only come as far as the point of feasibility studies for potential application in an offshore Indonesian reservoir, but the incremental recoveries reported in onshore reservoirs have been very encouraging with numbers ranging from 14 to 16 %.

Table II summarizes the six processes reviewed in this report.

Table I: List of IOR Processes Considered for GOM Application

Well Productivity Enhancement	
Near-wellbore permeability enhancement	1. Acidization/chemical stimulation
	2. Steam stimulation
Sand face area increase	3. Horizontal drilling
	4. Multi-lateral wells
	5. Fracturing
Well intervention facilitation	6. Dry trees in ultra-deep water
	7. RLWI (Riserless Light Well Intervention) technology
Bottom Hole Flowing Pressure Reduction (Abandonment Pressure & Well Productivity Benefits)	
Sea-floor flow boosting	8. Mud-line lift by gas injection into flowline
	9. Sea-floor MPP (Multi-Phase Pumps)
	10. Sea-floor fluid separation & electric-driven submersible pumps
	11. Sea-floor hydraulic-driven submersible pump
In-well artificial Lift	12. Electric Submersible Pump
	13.Gas lift
	14. Jet pumps

	15. Rod pumping
	16. Progressive cavity pumps
Well column lightening	17. Commingled production with overlying gas sand
Pressure Maintenance (Immiscible Displacement)	
Waterflooding	18. Sea water injection
	19. Sea-floor water injection
	20. Dump-flood water injection
	21. Powered dump-flood water injection
Gas flooding	22. Immiscible hydrocarbon gas injection
	23. Dump flood gas injection
	24. Immiscible nitrogen injection
	25. Immiscible carbon dioxide injection
	26. Flue gas injection
Intermittent gas injection	27. Huff 'n' puff single well gas injection (attic oil sweep)
Oil Viscosity Reduction	
Microbial fluid alteration	28. Microbial EOR - aerobic
	29. Microbial EOR - anaerobic
Thermal methods	30. Air injection/in-situ combustion - forward
	31. COFCAW (Combination of Forward Combustion And Waterflood)
	32. Air injection/in-situ combustion - reverse
	33. Steam flood
	34. Cyclic steam injection/steam soak
	35. Hot water drive
	36. SAGD (Steam-Assisted Gravity Drainage)
	37. Electromagnetic heating
Fluid swelling	38. Gas injection
Sweep Efficiency Improvement	
Improved areal sweep	39. Infill drilling
	40. Horizontal drilling, penetrating multiple reservoirs
Improved vertical sweep/thief zone control	41. Selective completion
	42. Water diverting agents (injection wells)
	43.Relative permeability modifiers (production wells)

	44. Polymer flooding for permeability variation mitigation
	45. Smart well technology - selectable intervals
Coning/cusping control	46. Horizontal drilling, appropriate distance from fluid contact
Mobility ratio improvement	47. Polymer flooding for injected fluid mobility control
	48. WAG - Water Alternating Gas flooding
	49. SWAG - Simultaneous Water And Gas injection
	50. FAWAG - Foam Assisted WAG
	51. Emulsion flooding (may also have S_{or} reduction benefits)
	52. Foam flooding
Gravity-assisted flood front control	53. GAGD (Gas-Assisted Gravity Drainage)
Double Displacement process (late life)	54. Gas flood of watered-out zones
	55. Water flood following gas flood
Residual Oil Saturation Reduction	
Gas phase miscible displacement	56. High pressure hydrocarbon gas injection/vaporizing gas drive
	57. Enriched hydrocarbon gas injection/condensing gas drive
	58. LPG slug injection (followed by gas)
	59. Hydrocarbon solvents injection (followed by gas or water)
	60. Miscible carbon dioxide injection
	61. Miscible nitrogen injection
Water phase low IFT displacement	62. Micellar flooding
	63. Surfactant flooding
	64. Alkaline flooding
	65. Alkaline-Surfactant-Polymer processes
	66. Alcohol flooding
	67. Fresh water injection/in-situ surfactant generation
Residual ganglia consolidation	68. Pressure pulsation
Stripping of residual oil	69. Gas cycling

Table II: Summary of Findings on IOR Processes from Literature Review

Process	Application Environment	Key Requirements	Benefits	Issues / Challenges	Potential Research Areas
Dump flooding	Mostly Middle East carbonate reservoirs	Prolific aquifer (gas/water)	Low implementation cost	Maintaining high injectivity rates due to low ΔP	Downhole technology to aide injectivity
Subsea water injection	North Sea & Brazil deepwater	Ability to integrate the subsea system to the platform operation	Operational flexibility where injection/processing capacity expansion can occur	New technology, water quality, and handling of sand production	Improve reliability, smaller and compact systems
Cyclic waterflooding	Heterogeneous sandstone and carbonate reservoir	Same requirements as those that apply to conventional waterflooding	Increase in recovery compared to conventional waterflooding	Same as those for conventional waterflooding e.g. water quality issues	Integrating of smart well technology with cyclic waterflooding
Cyclic gas IOR	Sandstone reservoirs in Louisiana, Texas, Kentucky, Trinidad & Tobago	Convenient gas source High S_o near wellbore Deep reservoirs	Able to recover waterflood residual oil in depleted reservoirs Possible application in a single well situation	Manage offset wells in highly fractured reservoirs to keep gas breakthrough minimized	Development of injection/production well completion techniques for application in ultra-deep deepwater environment with limited access
Hydrocarbon gas injection	Offshore North Sea & Persian Gulf (carbonates)	Local gas source; excess gas	Incremental recovery: 2% OOIP	Mobility control in very heterogeneous reservoirs	
Air injection	Sandstone & carbonate reservoirs in continental US	Relatively homogenous reservoirs	Reported estimated incremental recovery ~ 5%	Explosion hazards on platforms	

General Introduction

Since the discovery of the first commercial field (Cognac) by Shell in 1975, the Gulf of Mexico (GOM) has contributed significantly to the national oil and gas production. As per the MMS 2009-022 report, a total of 14.6 billion barrels of oil and 164 trillion cubic feet of gas was produced by the end year 2005. Knowledge Reservoir report KRNACKC081100 (2009) provides more relevant estimates of remaining oil in place of 39 billion Bbl (16.7 in Neogene and 22.5 in Paleogene – deepwater and ultra deepwater resources only) as a target for Improved Oil Recovery (IOR) methods which include secondary recovery, Enhanced Oil Recovery methods (EOR), and other production enhancements. The potential incremental recovery due to IOR processes using current technology has been identified to be about 3 billion bbl, most of which will come from Paleogene reservoirs.

The GOM is still in its infancy when it comes to application of IOR processes due to economic and technological restrictions. The key to breaking this barrier is identifying processes that reduce risk, well and/or facility costs. The objective of the RPSEA 1701 project is to identify IOR processes for deepwater GOM, their associated technical gaps that would prevent their application, and recommend future R&D programs to bridge the gaps. Identification of IOR opportunities would assist operators and producers in the GOM by extending the industrys' understanding of IOR processes and their application to deepwater and ultra deepwater reservoirs. In addition, it would allow their inclusion in the early stages of development planning of a field, such that facility and well designs can be optimized to take advantage of these opportunities.

LSU's role in this project has been to carry out a thorough and comprehensive IOR literature review study both onshore and offshore in order to capture the applicable experiences from around the world. Of all the IOR processes that were identified at the start of the project only 15 were prioritized based on the general understanding of why oil is left behind, how well understood and established the processes are, and the estimated R&D effort (see Table III). This screening stage was conducted through intense dialogue with the research partners and industry professionals. Of the 15 prioritized processes, the 6 that are described in detail in this report are dump flooding, seafloor water injection, cyclic water injection, air injection-low temperature oxidation, hydrocarbon gas injection, and single-wellbore gas injection/production. This report

will present their description, worldwide application, challenges, benefits, and existing opportunities for improvement.

Table III: Prioritized IOR Processes

IOR Process		Target Trapped Oil Mechanisms
Water injection		
1	Conventional water injection	Drive energy, sweep efficiency
2	Raw seawater injection	Drive energy, sweep efficiency
3	Aquifer dump flooding injection	Drive energy, sweep efficiency
Water-based EOR		
4	Microbial EOR	Capillary bound
5	Alkaline surfactant polymer (ASP)	Capillary bound; sweep efficiency
6	Chemical augmented waterflooding	Capillary bound
Gas injection		
7	Hydrocarbon gas injection	Drive energy, sweep efficiency
8	Hydrocarbon gas dump flooding	Drive energy, sweep efficiency
Gas-based EOR		
9	Nitrogen injection	Drive energy, capillary bound
10	CO_2 injection	Capillary bound
11	Air injection	Capillary bound, drive energy
Pumping & artificial lift		
12	Subsea multi-phase pumping	High abandonment pressure
13	In-well ESP	Abandonment pressure, sweep efficiency
14	In-well gas lift	Abandonment pressure, sweep efficiency
15	Subsea processing	High abandonment pressure
Well technology		
16	Low cost wells	Non-connected volume
17	Low cost well intervention	Abandonment pressure, sweep efficiency
18	Horizontal / multi-lateral wells	Non-connected volume, sweep efficiency

1.1 Literature Review on the Dump Flood

Dump flooding is a low cost waterflood method where water (or gas) from one formation is allowed to flow into another formation. Variations of dump flooding can be classified into two main categories: uncontrolled and controlled dump flood operations. Historically, dump flood processes have been uncontrolled. This is where gravity and pressure differential of two formations provide the energy to carry out the process. In an uncontrolled aquifer dumpflood, a well is drilled to penetrate both a prolific aquifer and a producing oil reservoir and under the right conditions significant quantities of water are allowed to flow from the aquifer to the oil reservoir. Figure 1.1 (Quattainah, 2001) illustrates an uncontrolled aquifer dumpflood case in the Umm Gudair field, Kuwait, where the Zubair aquifer formation is dumping water into the Minagish Oolite oil formation. In the case of a gas dump flood, gas from a deep gas reservoir is produced into a wellbore and allowed to crossflow to the gas cap of an overlaying oil reservoir, in order to support pressure in the oil reservoir. Figure 1.2 (Lau, 2001) is a gas dump flood example from the SW Ampa Block 11 field, Brunei, where gas from AW/AX gas reservoir is produced to the wellbore and injected into the AV gas cap formation. Both the aquifer and gas dumpflood fall under the uncontrolled category. On the other hand, the advancement of intelligent completions and downhole pumps is increasing and maturing the use of control dumpflooding. A classic controlled aquifer dumpflood uses only a pump to aid its water injection rates. However, as shown by Figure 1.3 (Stuebinger, 2000) fancier designs are taking advantage of smart completions and setting pace for future dumpflooding designs. In the illustrated pilot study case, hydrocarbons were separated in the wellbore by gravity and produced, as the denser aqueous phase was pumped into a lower oil bearing formation. Consequently, pump aided reverse dumpflood is used when the aquifer is underlying the oil reservoir, hence, the need for a downhole pump to inject water into the overlaying oil formation in order to maintain higher injection rates. Figure 1.4 (Yao, 1999) is an example from the Onbysk field, Russia where the Zav aquifer is underlying the Kiz oil zone therefore a downhole pump is needed to inject the water to the oil zone.

1.2 Application in Gulf of Mexico

No reported application.

1.3 Application Worldwide

Dump flooding has been applied extensively in the Middle East carbonate reservoirs. The Umm Gudair field in Kuwait (Quattainah, 2005) has a long history of using this IOR process for pressure maintenance. The Zubair aquifer provides pressure support to the Minagish Oolite oil reservoir. The dump flooding is in place since 1996 and provided up to 25% of the required water injection using at least 3 wells (SPE 106388). It is also noted that the power injection (from surface) is increasing with time as the field oil production declines. Zakum Field in Abu Dhabi (Abd Elaziz, 2006) was reported to have had 58 dump flood wells that were extensively used to maintain the reservoir pressure. This was prior to 1982 when powered sea water injection was introduced. October field offshore Egypt (Ibrahim, 2008) uses two methods of water injection. First, it produces water from the Zeit formation at a depth of 3000ft by ESP and injects it directly into water injection wells located directly adjacent platforms. Secondly, water is dumped from the Zeit source formation directly to the oil productive zone in the same wellbore by utilizing the existing pressure difference between the two formations.

1.4 Application Guideline & Benefits Estimation

Implementation of dump flooding depends upon there being favorable local factors; such as having a strong, prolific, high pressured aquifer, one that is preferably structurally higher allowing the use of gravity to inject water. If injection rates cannot be met or the aquifer is underlying the oil formation, a downhole pump can be installed to address either issue. A local favorable factor in deepwater GOM reservoirs is the high pressures with low bubble points. Therefore, with the right conditions such as the existence of prolific aquifer or gas reservoir, dumpflooding could provide a low cost way to sustain pressure in the hydrocarbon formations. Other generic requirements presented in most success cases in literature are following: the need for a versatile surveillance program to monitor water quality and process performance. Water quality has been a subject of concern that has plagued water injection projects especially in offshore areas. Even though dumpflooding has low risk of having water quality problems due to the high likelihood of compatibility between the aquifer and formation water, it's still crucial to have a monitoring or testing system in place for mitigation purposes. Coupling of smart well technology with dumpflooding allows its operations to be controlled and monitored. Another successful combination recorded in the Umm Gudair field (Quattainah, 2005) in Kuwait is the combination of infill producers and dumpflooding. Where the dumpflood injectors provide

pressure support and increase in oil sweep, as the infill producers allow the remaining unswept oil to be recovered.

Dump flooding is an attractive waterflooding variation especially in remote areas with little pressure maintenance history, lack of injection facilities, lack of platform space, or other limitation that make surface water injection cumbersome or uneconomical. With proper implementation and surveillance in place, dump flooding is usually viewed as a cost effective reservoir management and production strategy. This is because it eliminates the need for source water treatment because aquifer water tends to be compatible with formation water therefore water quality issues do not arise. This significantly reduces facility and flow line requirements and saves deck space in offshore environments. Other benefits of dumpflooding include reduction in environmental impact due to the elimination of water treatment chemicals, pumped ocean water, and drilling cost of source wells. Incremental recovery could be similar to that of a conventional waterflood if water injection can be achieved at required rates.

As dump flooding operation extends, uncontrolled dump flooding can lead to several reservoir management challenges, including: difficulties with flood front control, water breakthrough, conformance management, and inability to quantify crossflow rate in each well. With declining oil reservoir pressure, the pressure differential between the aquifer and the oil reservoir increases leading to possible excessive drawdown. In uncontrolled dump flood operations, it is difficult to quantify the crossflow rate in the well or monitor injecting or injection pressures. Also such an operation may have to overcome regulatory hurdles in environmentally sensitive areas such as deepwater GOM or areas where the aquifer is utilized by other ventures such as irrigation.

In the last few years, the development and advancement of smart well technology has provided solutions to challenges faced by uncontrolled dumpflood operations. The benefits of integrating dumpflooding and smart well technology are the ability to: monitor wellbore producing and injection pressure in real time, monitor crossflow rate and quantify flow rate in real time, determine productivity index and injectivity index for the producing zone and injection zone respectively, perform pressure transient analysis independently to both the production zone and injection zone to determine reservoir pressures in each zone, permeability-thickness (kh), skin, and potential for productivity/injectivity improvement through stimulation, independently stimulate and clean up both the production zone and the injection zone, pre-produce the injection

zone to reduce regional wellbore pressure and benefit from pre-production of hydrocarbons, soft start the dumpflood process, initially and after shut in, to reduce the draw down pressure transient and geomechanical shock to the wellbore of the producing zone, and to monitor and control drawdown pressure and flow flux rate to maintain flow condition within wellbore stability and sand control guidelines (Rawding, 2008). In the case of stacked reservoirs, simultaneous production and injection can be applied within a wellbore through commingling.

In spite of the advancement made in the use of smart completions, there is still a stigma of unreliability that needs to be improved and developed especially when considering their application in deepwater offshore environments. This is mainly due to lack of significant industry experience. Due to this fear of unreliability (Stuebinger, 2000), emerging smart well dump flood designs have trouble getting tested in prolific wells where there is a high potential for its application. Intervention in deepwater environments is very costly and can lead to loss in production and/or the well, and therefore the integration of smart completions in the recovery process demands high degree of reliability. As a result, this technology gap does present an opportunity for research and development to improve smart well technologies by increasing their reliability and performance. All in all, multipurpose wells that can inject and produce or perform multiple tasks would allow ventures that are deemed uneconomical due to high well costs (e.g. infill wells for injection/production) to be more applicable.

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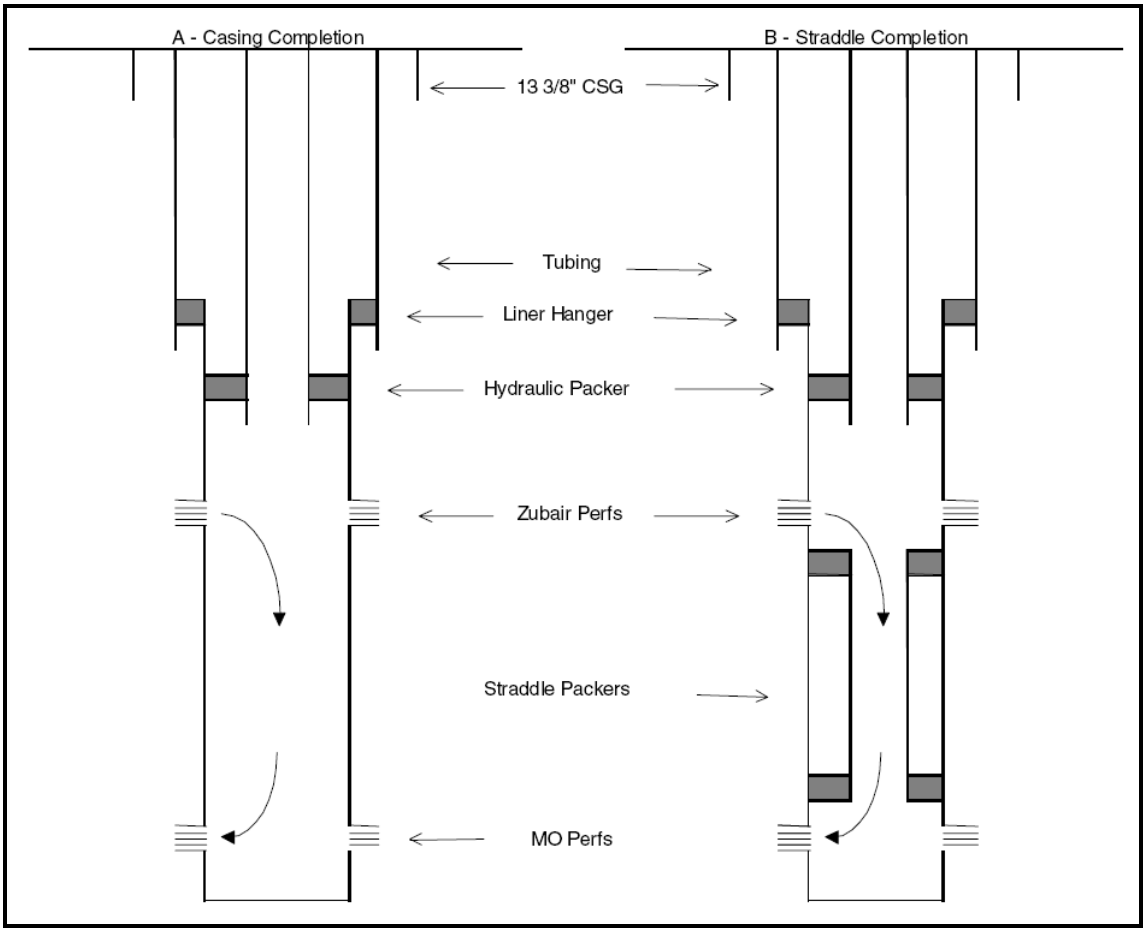

Figure 1.1: Schematic of an Uncontrolled Aquifer Dumpflood – Umm Gudair Field (Quttainah, 2001)
Zubair depth about 9000' to Minagish depth about 10300'
Water injected at about 20000 to 30000 bwpd at 3900 psi (SPE 106388)

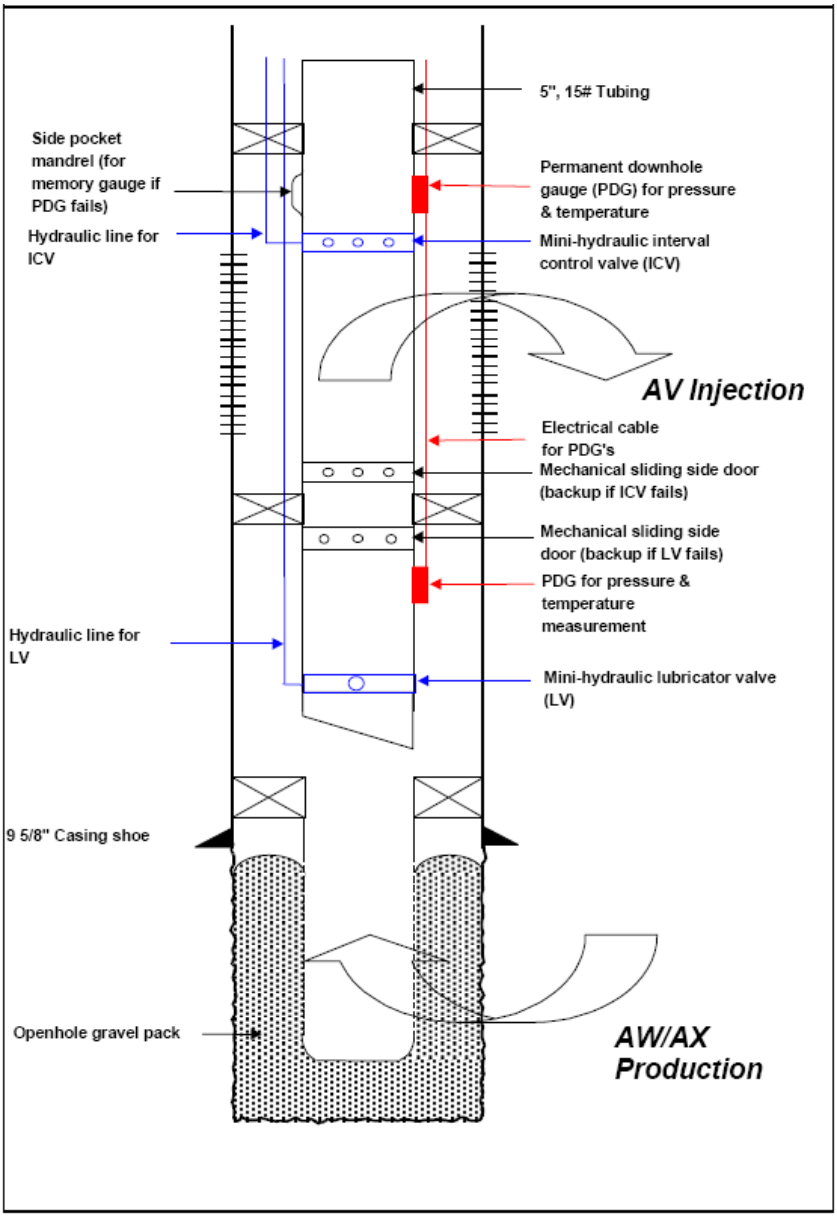

Figure 1.2: Gas Dumpflood (Lau, 2001); AV depth about 5900'-6600' with reservoir pressures of 1015-2320psi Gas injected from underlying AW/AX is at a rate of 17-35mcf/day

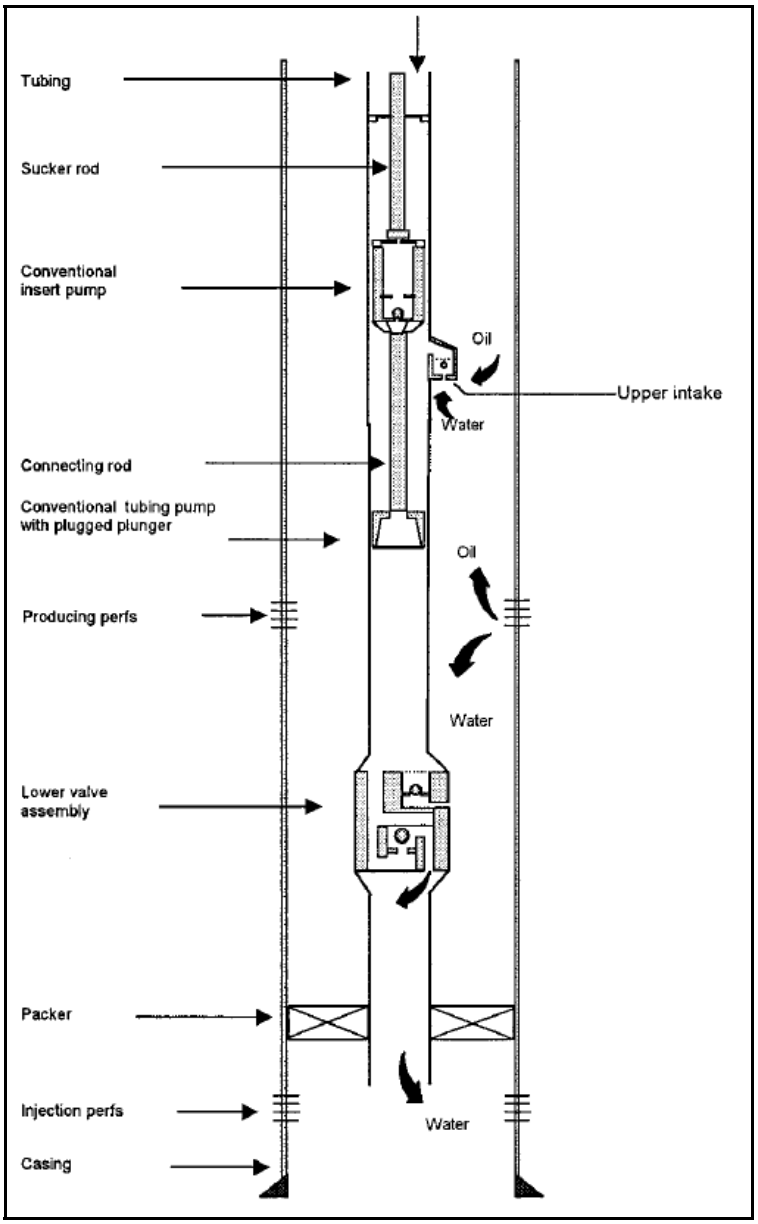

Figure 1.3: Controlled Dumpflood (Stuebinger, 2000); The dual action pumping system (DAPS), shown here on the down stroke, utilizes two intakes and two pumps to segregate oil from water in the annulus. It injects water on the down stroke and lifts oil and some water on the upstroke, while free gas flows up the annulus. The productive zone is perforated from 2970'-2978'

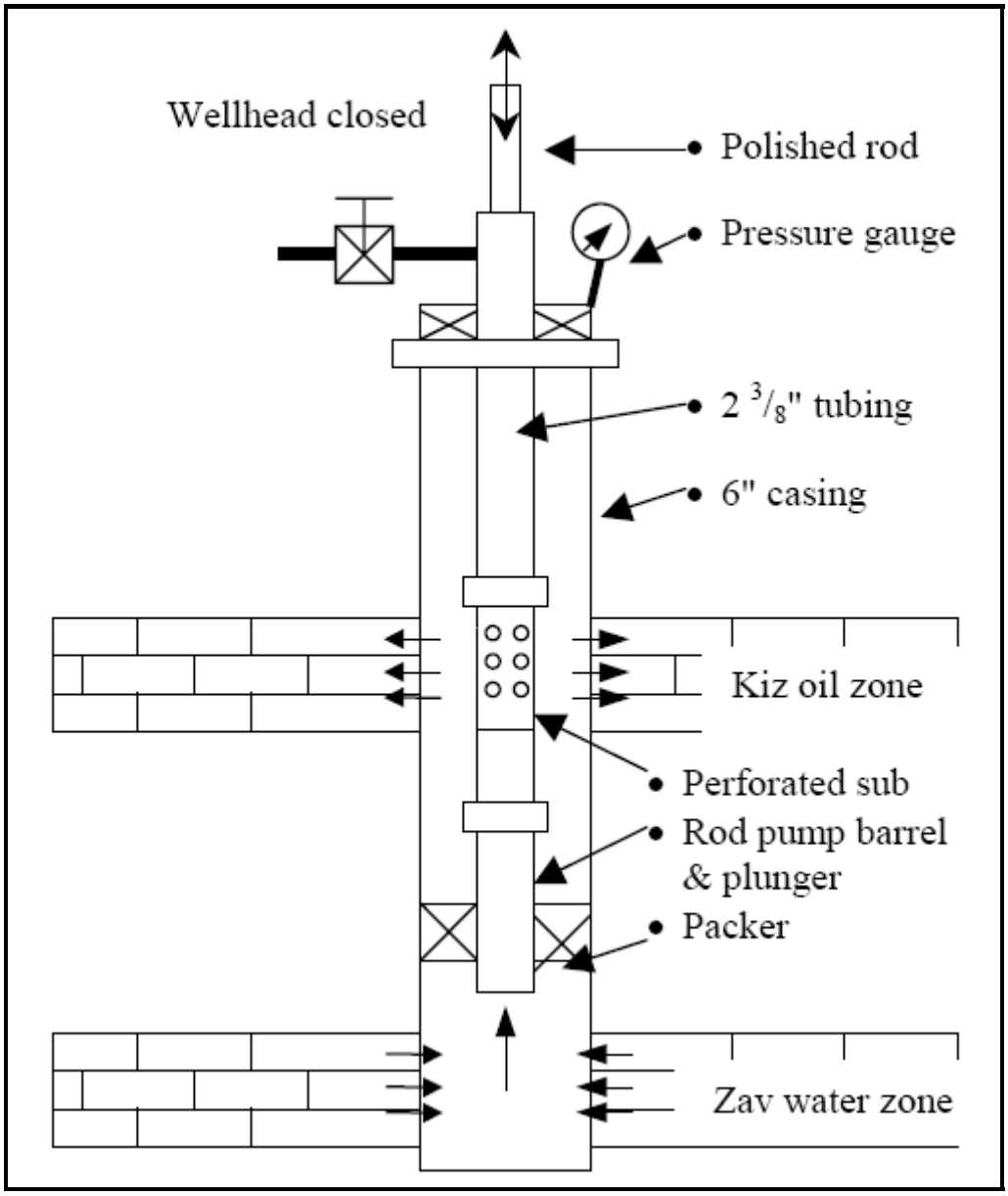

Figure 1.4: Reverse Dumpflood (Yao, 1999)
Kiz zone depth is 3800', with a permeability of 30md and porosity of 13%, and an initial pressure of 1239psia
Zav zone depth is 4065', with a permeability of 30md and porosity of 10%, and an initial pressure of 1778psia
The production of a pump aided reverse dump flood was 80stb/d as opposed to 25stb/D without a pump

2.1 Literature Review on the Subsea Water Injection Processes

Subsea separation and water re-injection and subsea raw water injection processes are at a very early stage in their operational life, hence there are many technology gaps that exist for improvement. Some of the technologies, such as seabed multiphase pumping, have risen to the status of proven technologies. Other technologies, including aspects of subsea separation and water re-injection and subsea raw water injection, are still in the infancy stages of development and have not been implemented widely. Therefore, information on these technologies is limited. Next generation systems need to be more compact, adaptable, and reliable especially in harsh remote environments. This report will give an individual and overall synopsis on both processes, capturing their worldwide applications, challenges, benefits and opportunities.

2.2 Subsea Separation and Water Re-Injection System Review

In this past two decades, subsea separation and water re-injection systems have evolved from a concept to an operational stage. However, still in its infant stages of operation these systems are proving to increase recovery and improve the economics of offshore oil and gas fields, while also having a positive impact on the environment. The two main variations of the systems: 1) the liquid-liquid separation system, where water and oil are separated followed by water re-injection for pressure maintenance in the reservoir, as oil and gas are pumped to the platform or shore. 2) In the liquid-gas separator, gas is naturally flowed to the production facility while the liquid is boosted to the platform in a separate flowline. Most subsea processing projects have relied on employing subsea multiphase pumps without the need for separation; however, the reduction in backpressure on the wells is limited by the free gas fraction at the pump inlet, hence the development of subsea separation systems.

2.3 Application in Gulf of Mexico

The first implementation of subsea separation and production facilities has been in Shell's Perdido Development, an ultra-deep water development (at 9,627 ft subsea the Tobago well is the world's deepest well in production), in the Great White, Silvertip and Tobago fields. These fields are of the Oligocene, Eocene and Paleocene period and have never been produced from in the Gulf of Mexico (Snyder & Townsley, 2010). Some of the important challenges faced during the planning of this project were:

- The reservoirs are relatively shallow, hydro-pressurized and require artificial because of the combination of low reservoir pressure and excessively high backpressure from the hydraulic head in the 7,800 ft risers.
- The Great White field is expected to have some degree of compartmentalization due to a high degree of faulting which means that a higher well count is needed.
- Being that Perdido is slated to be the first development and production from a Paleocene reservoir the biggest risk to the success of the project was the uncertainty in subsurface recoverable volumes. To minimize the financial risk inherent in this geologic uncertainty it was decided to minimize the upfront capital investment. Introducing the use of new technology was one way that was achieved. The new technology encompassed the use of a subsea boosting system (see Figure 2.1), a wet tree direct vertical access well system and a high pressure drilling and completion riser with a surface BOP. All the produced fluids are commingled on the seafloor and directed to the subsea boosting system. The subsea boosting system consists of 5 identical units that separate gas is from the produced liquid after which the liquid is pumped up to the host platform. The components and controls of the 300 ft caisson separation and ESP system of the subsea boosting system were tested onshore over the range of fluids and flow rates expected in the field. A more detailed schematic of the caisson-ESP separator system is shown in Figure 2.2.

2.4 Application Worldwide

Most of the worldwide applications have been in the North Sea and Campos Basin, Brazil. The first subsea separation, boosting and re-injection pilot system was put into full operation in August 2001 in the Troll field, which is located 50 miles west of the Norwegian cost in the North Sea (Vu, 2009). This subsea system employs a gravity-based separation system at a depth of 1,115 ft. The Troll Pilot plant has a footprint of approximately 66 ft by 98 ft, with a 59 ft long and 10 ft diameter separation vessel (Michaelson, 2003). The design capacity of the separator vessel is for 38,000 bbl/day of water, 25,000 bbl/day of oil, and 28,251,733 ft^3/day of gas (Horn *et al.* 2003). The system separates produced water from the oil and gas streams from a maximum of eight wells that can be routed to the separator (Grieb, 2008). The benefits of this type of system are increased oil production rates and lower discharges of produced water from the platform as illustrated by Figure 2.3.

Subsequently, the next generation subsea separation, boosting and water re-injection system was installed and started up in the Tordis field in 2007 (Gruehagen, 2009). This system was designed to improve the project economics by providing a boost to the hydrocarbon stream as well as water separation and disposal. The Tordis field is located in the North Sea off the coast of Norway in water depths of 656 ft. The Tordis subsea project links four maturing fields, and is the first commercial subsea processing system. The processing system includes a water/sand separator, multiphase pump, includes internal level detectors to measure the sand, water, and oil fractions. The desander module injects sand into the reinjection stream downstream of the water injection pump, thereby reducing wear on the injection pump. The produced water and sand are reinjected into the subsurface (producing reservoir). Both the Tordis and Troll field are operated by StatoilHydro.

The subsea oil/water separation of heavy oil system was installed in the Marlim field, Campos Basin as the world's first system for deepwater subsea separation of heavy oil and water that also includes re-injection of water to boost production. The target for the subsea system was set as 10% watercut in the oil gas stream and 100 ppm of oil in the separated water stream (Figueiredo, 2006). In 2002, PETROBRAS began activities on the subsea water separation system, which was broken into 3 phases. The first phase was devoted to collect data about the reservoirs and the produced fluids to allow the scenario definition and provide data for the next phase. The second phase was begun in 2003 and its objective was to contact suppliers of subsea and process equipment in order to develop the system needed for the defined scenario. The third phase scheduled for the beginning of 2007 was the initial installation of the prototype.

A subsea gas/liquid separator (Grieb, 2008) such as the Vertical Annular Separation and Pumping System (VASPS) was installed in the Marimba field, Campos basin. VASPS separation occurs in low pressure at a production capacity of 9,000bbl/day (Figueiredo, 2006). After separation, the gas stream naturally flows to the production unit and the liquid stream is boosted by a conventional pump through a different flowline. The Marimba Field is located in the southeastern section of the Campos Basin. PETROBRAS installed a VASPS in 2001 at a depth of 1,295 ft with a tie-back distance to the P-8 Platform of approximately 0.62 mile (Ribeiro *et al.*, 2003). The initial VASPS installed at the Marimba Field only operated from August 2001 to December 2001. It had to be shut down after five months of operation due to mechanical failures of the ESP unit. During this short operational period, VASPS boosted the production of the well

by one-third of its previous daily production rate (Ribeiro *et al.*, 2003). In January 2004, a rig intervention replaced the damaged ESP and the VASPS prototype resumed operation in May 2004. The system has operated successfully with no major malfunctions since it was restarted in May 2004.

2.5 Application Challenges and Benefits Estimation

Early subsea separation and water re-injection systems went through a steep learning curve resulting in the newer generation systems, especially ones that have been pilot tested, to be more reliable. The major issues confronted in the application of this technology are: the quality of the water re-injected, handling of produced sand (re-inject or dispose it on the sea floor), and understanding and managing complex fluids systems.

On the other hand, there are many benefits associated with this process. Subsea water removal from the production stream reduces back pressure therefore increasing production and recovery. As a field matures, the use of a subsea separation and water re-injection system allows for increase in produced water handling capacity on the platform without large and expensive retrofits therefore permitting an optimized use of the existing infrastructure. This does prolong economic life of a field.

2.6 Subsea Raw Seawater Injection System (SRSWI) Review

Subsea raw water injection is an innovative technology that allows for a water injection facility to be installed and operated at the seabed. Waterflooding is a recognized method of increasing recovery and production rate by maintaining reservoir pressure. The conventional option of injecting water via a dedicated pipeline from a platform tends to be costly while delivering less in terms of pressure boost especially in deepwater environments.

2.7 Application in Gulf of Mexico

No reported application.

2.8 Application Worldwide

The Canadian Natural Resource (CNR) implemented the first SRSWI system in the world at the Columba E field, North Sea. Columba E is the largest and most southerly of five faulted structures known as the Columba Terraces, with 270 MMSTB of oil originally in place. As of

February 2007, Columba E was reported to have produced nearly 11 MMSTB of oil (Rogerson, 2007). CNR's goal for the new waterflood scheme is to extract another 30 MMSTB from the four producer locations which are connected to at least an estimated 80 MMSTB in place using this system. Later in the field's life, the raw water injection system could be re-deployed or replicated to access other targets or used to replace an existing water injector well in a different field.

StatoilHydro's Tyrihans field has a scheduled installation of the world's largest and most powerful SRSWI by the end of 2009. This field is located about 22miles south of the Åsgard field on the Norwegian continental shelf and consists of two structures: Tyrihans South that consists of a thicker oil column with a rich gas cap and Tyrihans North is a gas condensate accumulation with a thick underlying oil column. The SRSWI will be installed in 885ft of water with 2 centrifugal pumps that have an injection capacity of 126,000bpd and can deliver a total shaft power of 7340hp (Grynning, 2009). This system is expected to boost oil production from the field by 10% over current recoverable reserves which are approximately 19 million barrels of oil. The field will consist of 5 subsea templates, 4 for production and gas injection and 1 for raw seawater injection. The pumps will take in 89,700 bbl (Grynning, 2009) of untreated seawater daily and inject it back into the reservoir between Tyrihans North and Tyrihans South reservoirs. Optimal reservoir pressure support is expected to be obtained by gas injection from the Åsgard B platform and the seawater injection. The production stream will then be carried to Kristin platform for separation. The design and testing of the SRSWI system is completed and the next phase schedule for this year (2009) is the installation processes. Some of the early concepts considered were re-injection of produced water, or a combination of seawater and produced water through a flow line from the Kristin platform. However, they were abandoned due to the high cost of the flow line and given the low probability for formation water breakthrough to the oil producing wells.

PETROBRAS had scheduled to install the SRWI prototype in the second half of 2006 in the Albacora Field. However, there is no further information in the literature on the progress of the system installation and operation. This field was deemed to be an ideal candidate due to the need to increase the water injection flow rate in some of the reservoirs and several technical constraints limited the possibility to either install or upgrade the platform. Hence, SWRI system was found to be the ideal solution. The system was planned to be installed in 1444 ft of water

and it was estimated to have a maximum flow rate of 31,450 bbl/day with a maximum differential pressure of 2,400 psi and nominal electrical power of 1.5MW (Figueiredo, 2006).

2.9 Application Challenges and Benefits Estimation

Among the challenges faced by subsea raw sea water injection facilities are seawater compatibility with the reservoir rock and fluids, and microbiological control. The above systems are not coupled with water treatment. Other major obstacles in wider use of this technology are to develop better subsea filtration systems and improve the equipment reliability.

On the other hand, the benefit of using subsea water injection facility is that it can provide considerable water injection rate to the already producing oil field without major modifications on the existing platform. It also makes water injection feasible in areas with restrictions to install or upgrade a conventional system. It may become an economic water injection alternative with lower CAPEX and OPEX than conventional systems especially in large deepwater and ultra deepwater developments. A subsea water injection facility makes it possible to use smaller floating production units and smaller processing facilities. It provides more flexibility with respect to the timing of the water injection startup date avoiding upfront investments and system installation when water injection requirement is uncertain in the early stages of a field development.

2.10 Overall Application Challenges, Benefits, and Opportunities

Both subsea separation and water re-injection and subsea raw water injection have made great progress in the past decade. However, most of these systems are still in their early stages of implementation and operation therefore, their challenges and benefits are still being revised with each profound lesson learned. The high capital required to first install the system creates a challenge especially in marginal fields, or risky ventures especially if the technology is not fully proven. Initial insertion of a subsea separation system in a production layout not designed for it can pose major challenges. Once the subsea system has been implemented, operational flexibility where injection/processing capacity expansion can occur with no or minimum impact on the production units. Cost benefits can however be found in the passing on of the production equipment to another venture where investment costs can be dramatically reduced. Additional cost benefits include potential increase in recovery factor by increase in water injection. Lastly,

these subsea systems are designed to aid in the later abandonment of wells with high water cut, as the water separated at the mud line zone minimizes the impact of liquid processing capacity of the production facilities.

Several of future planned projects in subsea separation and water injection are:

- Total's Pazflor project in offshore Angola scheduled for 2011 will be utilizing the region's first-ever subsea gas/liquid separation system (FMC Technologies, 2009).
- Shell's Perdido project scheduled for 2010, is currently under development and will also incorporate subsea boosting and separation to achieve production (FMC Technologies, 2009).
- The North Sea has a few planned projects as shown in Figure 2.4 (StatoilHydro, 2006). The Åsgard field plans to have two subsea 9MW compressors with a 47km step out installed for 2011. In addition, the Snøhvit field (2019) and Ormen Lange (2016) are planning to install a subsea compression plant with a large step out.

Figure 2.5 (FMC Technologies, 2009) is a table by FMC technologies illustrating future planned projects the company is working on designing and developing.

The opportunities to fully exploit the benefits of these systems, lies in the application of the lessons learned from the previous operating systems which would allow for faster improvement on the next generation subsea systems, hence making them more reliable, versatile, and adaptable. Merging of subsea water injection with subsea separation and water re-injection would create a power system that would have high performance especially in cases where there is high potential of water breakthrough. Improving water quality by creating better filtration systems and chemical injection programs would solve major water quality issues. Development of subsea gas compression would greatly aid in the potential implementation of gas injection related IOR processes. Design of more compact systems would allow for flexibility in installation and use while reducing costs. More reliable and refined monitoring systems are also needed. Oil in water measurement from subsea separators is an area requiring more innovations and experience as none of the instruments used at topside's can be easily adapted to subsea use.

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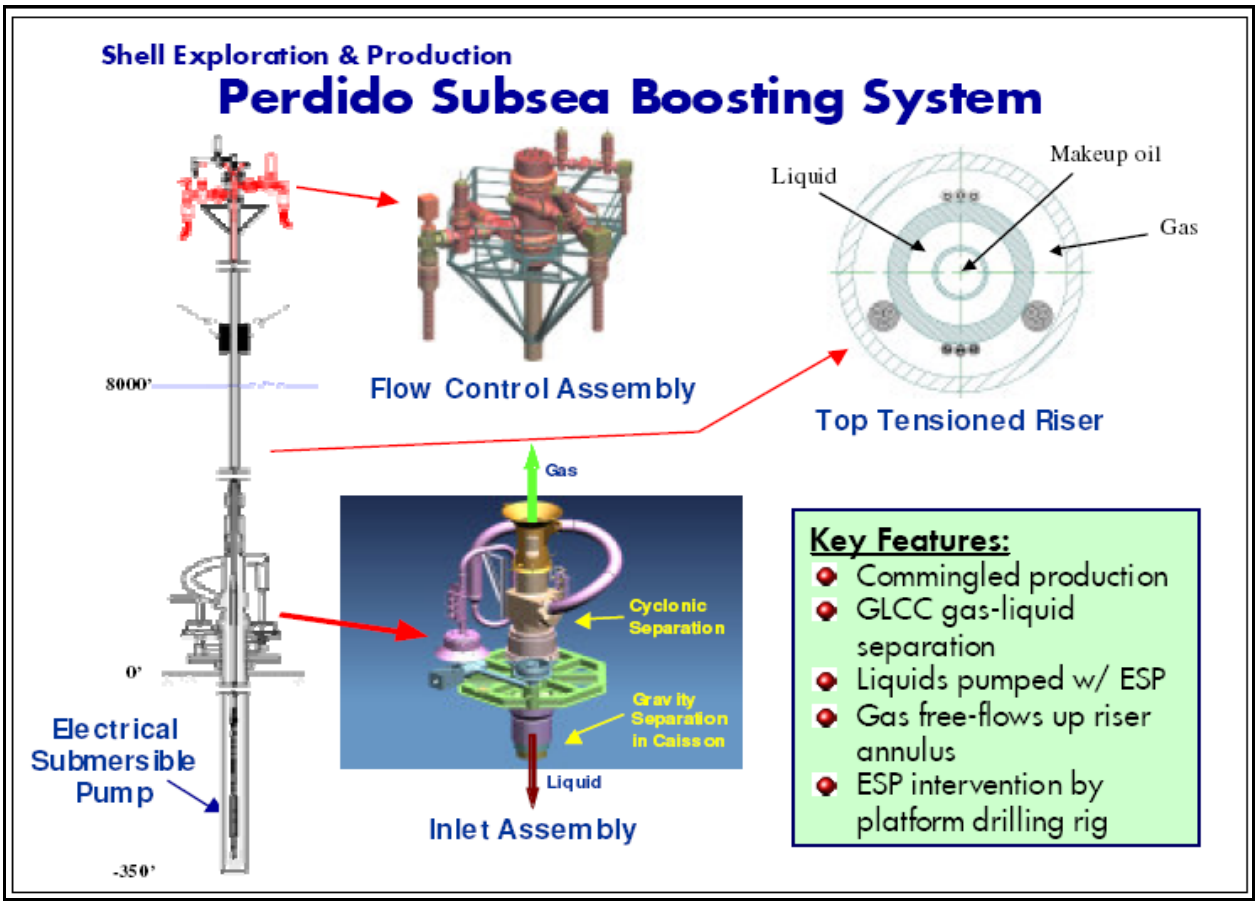

Figure 2.1: Perdido Subsea Boosting System (Snyder & Townsley, 2010)

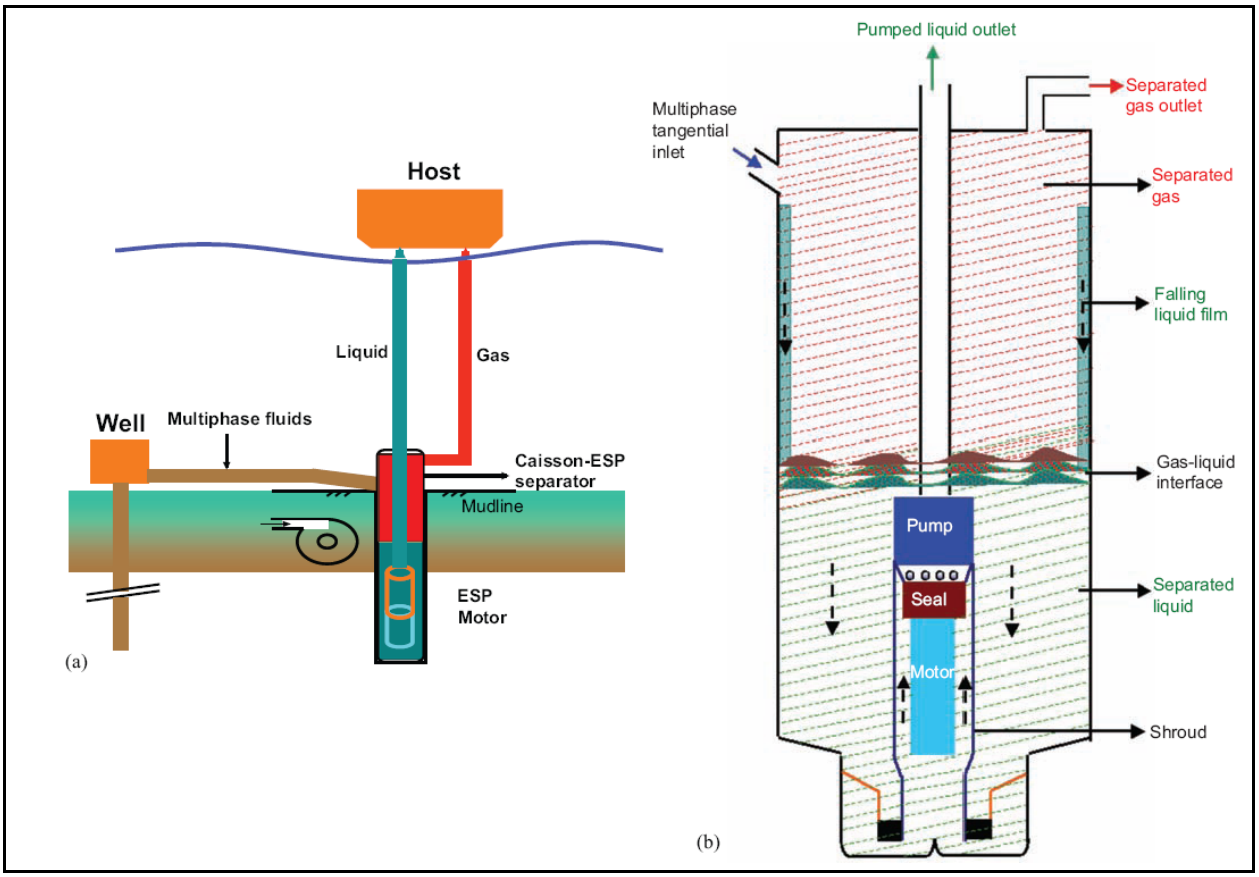

Figure 2.2: Flow Schematic of Caisson-ESP System (a) and Detailed View (b) (Parshall, 2009)

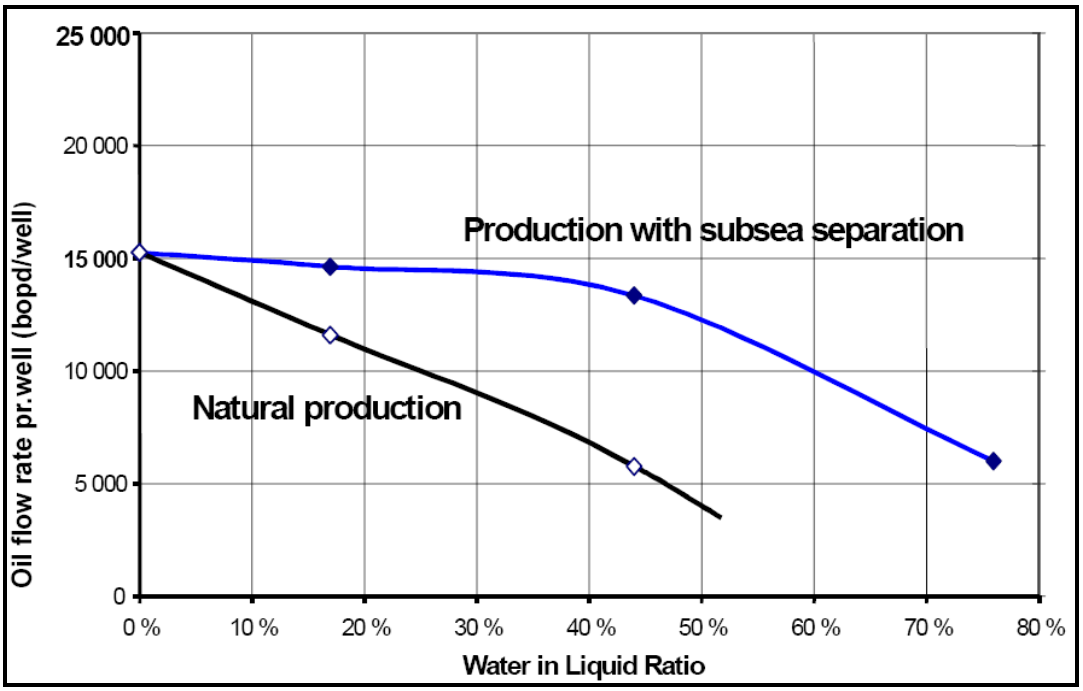

Figure 2.3: Production Comparison With and Without Subsea Separation (after Michaelson, 2003)

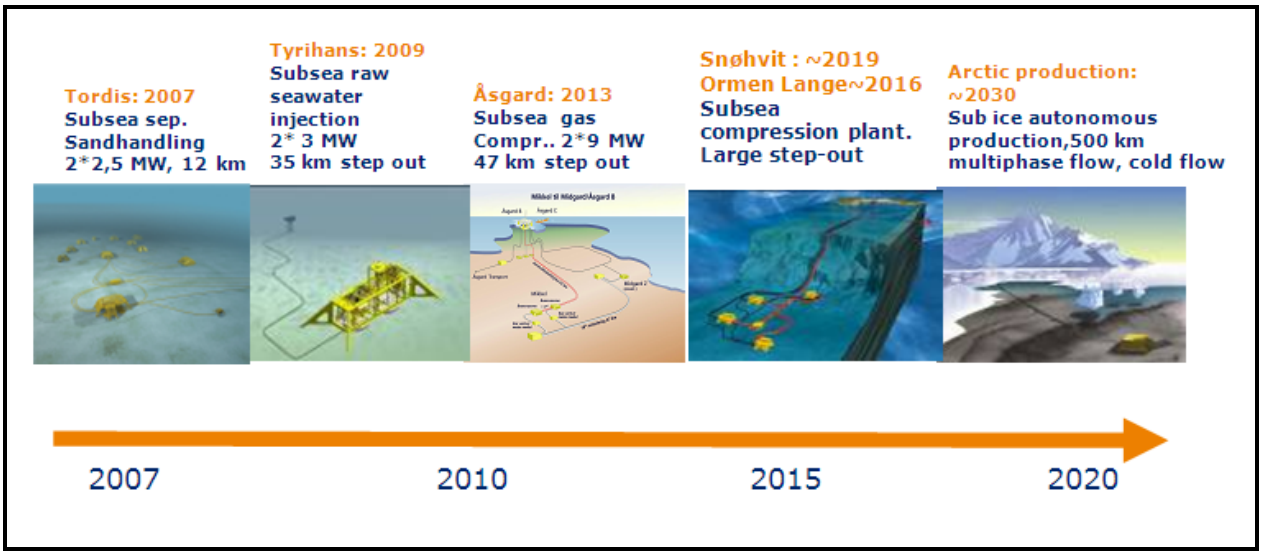

Figure 2.4: Planned Projects in Subsea Separation and Water Injection in the North Sea (StatoilHydro, 2006)

FIELD	CUSTOMER	AWARD	TYPE	PROJECT DRIVERS	SOLUTION
TORDIS	StatoilHydro	2005	Brownfield	Increasing water production	Water/Oil Separator with sand handling and boosting
BC-10	Shell	2006	Greenfield	Low Reservoir Pressure/ Heavy oil	Gas/Liquid Caisson separators with ESP's
PERDIDO	Shell	2007	Greenfield	Low Reservoir Pressure/ Heavy oil	Gas/Liquid Caisson separators with ESP's
CASCADE & CHINOOK	Petrobas	2007	Greenfield	Low Reservoir Pressure/ Heavy oil	Horizontal ESP's on seabed
PAZFLOR	Total	2008	Greenfield	Hydrate Formation Risk/Low Reservoir Pressure	Gas/Liquid Separation with seabed boosting

Figure 2.5: Overview of FMC Technologies' Projects. Brownffields are mature fields while greenfields are the newer fields (FMC Technologies, 2009)

3.1 Literature Review on the Cyclic Waterflood

Cyclic flooding, also known as cross-flooding or pressure pulse technique, is an unsteady water injection process based on the combination of two processes, pulsed injection/production, and alternation of waterflood patterns. Cyclic injection is based on alternate pressurizing and depressurizing stages of the reservoir, leading to reallocation of injection volumes between waterflood well patterns. Each injection cycle consists of 2 phases:

1. Pressurizing half cycle: water is injected at a high rate as production is continued at a constant rate. This will increase pressure in the reservoir which may exceed the original pressure. The increased pressure will at first be in the high permeable zone or fracture network where it can play a positive role in opening connectivity of discontinuous micro-fractures or low permeable zones, hence, pushing water in unswept low permeable zones.
2. Depressurizing half-cycle: water injection is ceased or reduced and production is continued at a constant rate, therefore the reservoir pressure is allowed to drop. In the low permeable zones, imbibed water is capillary retained and oil is released. Reduced pressure and interrupted injection should facilitate counter-flow of oil from the low permeable zones to the fracture network or high permeable zones and hence to producing wells.

Major contribution of oil recovery increase in a heterogeneous reservoir during cyclic flooding comes from the acceleration of cross-flow between low and high permeable zones or between layers of different permeability. Capillary and gravity forces usually present in a reservoir play a secondary role in a cyclic waterflooding process since the fluid re-distribution is slow in comparison with cyclic well control, pressure drainage gradient in a reservoir and viscous dominated flow. The primary contribution to cross-flows during cyclic waterflooding usually comes from compressibility effects. Under cyclic flooding conditions the pressurizing and de-pressurizing half cycles are controlled by adjusting injection and in some cases production rates.

From the widespread application of the process in Southern Daqing oil fields (Zhongron, 1995), cyclic flooding was found to improve performance at all development stages of a reservoir, especially at the early stage of the oilfield development where the results are more obvious and more favorable. Apart from the conventional cyclic flooding method, various variations have been developed such as: Cyclic Production Scheme (CPS) that requires alternate shutting and flowing wells with high water cut over a predetermined period of time. The other

variation is the Pressure Pulsed Technique (PPT) that uses a piston and cylinder tool in order to force fluid under high pressure into the formation.

3.2 Application in Gulf of Mexico

No reported application.

3.3 Application Worldwide

Cyclic water injection has been successfully applied in a number of sandstone and carbonate oil fields in Russia, China and USA and pilot tested in other countries such as Saudi Arabia and Germany. However, no applications have been reported in the offshore regions.

In the beginning of the 1960's, the Jablonev Ovrag and Kalinovskoye fields in the Volga Ural area or the former Soviet Union (Shandrygin, 2008), showed improved oil production under cyclic water injection. Oil recovery improvement due to cyclic injection on the fields in the Samara region varied from 0.4 - 4% OOIP for the period of 1968-1984 (Surguchev, 2008). In the Tatar Republic, more than 12.6 million barrels of additional oil was produced from carbonate reservoirs with low to medium viscosity oil. Cyclic injection was successfully implemented in several formations of the giant Romashkino field in the Tatar Republic where more than 50% of the injection wells were involved in the cyclic injection process. In West Siberia, cyclic waterflooding was successfully applied at several major oil fields such as Trekhozernoye, Ust-Balyk, Mamontovo, Pravdinskoye, Fedorovskoye, and others. The total cumulative additional oil production by cyclic water injection in the 3 main oil producing regions of Russia amounted to 163.4 MMstb (23.2 million tons) in 1984.

In China (Surguchev, 2008; Zhongron, 1995), extensive cyclic waterflooding has been performed in the southern oilfields of Daqing. The Daqing field formerly called Taching, is the largest oil field in the China, located between the Songhua river and Nunjiang river in Heilongjiang province. Cyclic waterflooding testing began in 1982 in the Tainan oilfield where positive effects were obtained. Full-scale cyclic waterflooding was initiated in the newly produced Punan oilfield in 1985. In 1986, conventional waterflooding in the Pubei oilfield was converted into cyclic waterflooding. By the end of 1993, all the 498 water injection wells in Putao-hua oilfield and Punan oilfield had been converted to cyclic waterflooding. The effectiveness of cyclic versus conventional waterflooding flooding in Daqing can be made by

comparing the results of the Tainan oilfield with Taibei field which share the same structure, geological characteristics, fluid properties, well pattern arrangement, and production form. After 12 years of cyclic flooding, Tainan oilfield's oil recovery was 14.7% with composite water cut of 63.14 %. During the same water cut stage (60%) in the production history of Taibei field that used conventional water flooding, its oil recovery was 4.6% lower than the Tainan oilfield. The average increase of water cut was reported to change as follows: after 1% OOIP was produced the average simultaneously produced water rate was 3.3% in Tainan field and 6% in Taibei field per 7.3 barrels (1 ton) of oil.

In Saudi Arabia (Almutairi, 2008), the Cyclic Production Scheme (CPS) was applied as the first field trial in the world. This process was applied in one of the mature oil fields by Saudi Aramco to maximize ultimate oil recovery and reduce water production while enhancing reservoir pressure. Field results are not listed in literature however; the literature described conceptual simulation model results that predicted a significant reduction in cumulative water production of up to 50%, no change in cumulative oil production, a slight reduction in cumulative water injection, and a small increase in average reservoir pressure by about 50psi.

In Germany (Groenenboom, 2003), the Pressure Pulsed Technique (PPT) was field-tested in a heavy oil field in Germany. The part of the reservoir where PPT was implemented had experienced edge water drive and in addition to waterflooding. The viscosity ranged from 90-120cp at initial reservoir conditions with a stock tank API gravity of 24.5, a bubble point pressure of 798 psi, and initial GOR of 20 scf/stb. The reservoir is a weakly consolidated sandstone reservoir, faulted and slightly dipping towards the southeast with a top depth ranging between 1838 ft to 2904 ft. The thickness of the productive Bentheimer sandstone layers thickness averages between 65 ft to 114.8 ft and separated by shale layers. The sandstone's porosity and permeability ranged between 20-30% and 100-5000 mD, respectively. The initial reservoir pressure at 2460 ft was reported to be 1160 psi which corresponded to the pressure gradient of 0.48 psi/ft. By the start of the PPT implementation, 25% of the STOIIP (753.2 MMstb) had been recovered, reducing the pressure gradient from 0.48 psi/ft to 0.27-0.31 psi/ft. Two of the three objectives of the trial were met, namely equipment operability and increased injectivity. The equipment outperformed the project scope of operating remotely for a period of 5 months in harsh corrosive wellbore conditions compared to the target three months. An average increased injectivity of 30% was recorded during the trial with a plateau injectivity enhancement

of 40% during the first two months. The increase in production was difficult to evaluate due to the absence of high quality data.

3.4 Application Guideline, Challenges, and Benefits Estimation

For a successful cyclic flooding outcome, equilibrium of injection and production must be maintained by finding the proper intermittent injection cycle. An adequate and reasonable cyclic water injection rate must be determined from the actual the oilfield practice. Similar challenges faced by conventional waterflooding are encountered by cyclic waterflooding. However, a major hindrance has been finding literature on the specifics of cyclic flooding, such ideal injection patterns. On the other hand, the most noted benefit of this process is the increased production oil recovery rate at reduced water cut, which would likely extend the life of recovery by extending the economic limit of the field. The mitigation of produced water alleviates the need for the expansion of produced water facility or handling equipments. Cyclic injection will improve waterflooding efficiency at minimal additional cost if waterflooding has been established in the field of interest. Improved sweep, accelerated oil production, and reduced water cut are the likely positive aspects of the cyclic waterflooding. Additional recoveries compared to waterflooding have been documented in China, US, and Russia (Surguchev, 2008; Shandrygin, 2008; and Zhongron, 1995).

Finally, cyclic flooding has been found successful in heterogeneous sandstone and carbonate onshore reservoirs. Unfortunately, there seem to be no documented cyclic flooding cases in the offshore area. The main modification in cyclic flooding compared to conventional waterflooding is the pulsing of the injection rate, therefore this process should be applicable in an offshore reservoir that is suitable for waterflooding. Due to the limited space on platforms, this process can be coupled with a subsea water injection system. For layered reservoir formations, smart completions maybe used to inject and pulse water in the formations of interest independently within a wellbore. However, for both to be attractive to an offshore operator, the state of reliability and performance for both subsea injection systems and smart completions have to be improved.

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4.1 Literature Review on the Huff 'n' Puff (Gas Injection) Process for the Recovery of Light Oil

4.1.1 Introduction – Description of the Process

Gas injection has been used by industry for improving oil recovery for many years. One of the variations of gas injection as an improved oil recovery (IOR) process that has been applied in the field is the injection of gas in a cyclic manner, i.e. in huff and puff mode. This process may be applied as the secondary recovery process or as tertiary recovery process after water flooding. The process is generally suitable for light oil reservoirs using the injection of CO_2, although the application in heavier oil reservoirs is not uncommon.

The huff 'n' puff process is a cyclic single well process involving the following three stages (Miller and Hamilton-Smith, 1998):

1. The injection phase – gas (e.g.: CO_2) is injected into the area near the wellbore.
2. The soak phase – the well is shut in for a pre-determined period of time to allow the injected gas to interact with the reservoir fluids (dissipation and/or dissolution) contained within the formation.
3. The production phase – the well is placed back on production.

In the soak phase the injected gas can possibly interact with the reservoir fluids as follows:

- It can act as a solvent thereby increasing the relative permeability to oil.
- It can imbibe into the rock matrix and release oil trapped due to capillary forces.
- It can reduce the relative permeability to water by acting as a blocking agent.
- It can add energy to the system to help drive fluids to the well.

In the case of the use of CO_2 as the injected gas, some of the proposed recovery mechanisms have been (Gondiken, 1987):

- Reduction of the oil viscosity due to the high solubility of CO_2 into oil, even at immiscible conditions.
- Swelling of the oil also caused by dissolution of CO_2 in it.
- The reduction of interfacial tension resulting in the enhanced ability of the oil to flow through the porous media that is the reservoir rock.

- When the injected CO_2 reacts with hydrogen ions, it forms carbonic acid which in turn can react with the (carbonate) reservoir rock leading to a potential increase in reservoir permeability.

Subsequent history matches of field performance using numerical simulation have made it clear that the principal oil recovery mechanisms for the CO_2 huff 'n' puff process are oil swelling, oil viscosity reduction and gas relative permeability hysteresis (Denoyelle and Lemonnier, 1987). The gas relative permeability hysteresis (imbibition and drainage) results in gas and water blocking in the back production phase while the lower residual oil saturation to gas as compared to water results in an increase in oil recovery ($S_{org} < S_{orw}$).

The performance of a cyclic gas (CO_2) injection project is usually evaluated using the following parameters:

- Incremental oil recovery: the incremental oil recovery is usually calculated as the increment oil recovered over the baseline forecast production. The baseline production is often determined through regression analysis of the production history (decline analysis) prior to the huff 'n' puff implementation. In case the forecast reached the economic limit a straight-line production profile was assumed with no further decline. The post-huff 'n' puff production is generally also fit using regression analysis.
- Gas utilization: this is defined as the volume of gas (CO_2) injected measured at standard conditions (unit: Mscf) divided by the estimated incremental oil (expressed per barrel incremental oil recovered). Another way of calculating the gas utilization factor is by relating the injected gas (CO_2) measured at reservoir conditions to a barrel of incremental oil recovered. The latter is referred to as the CO_2 reservoir utilization factor.
- Stimulation ratio: is defined as the average monthly oil production rate for the first month after the huff 'n' puff application divided by the average monthly production rate prior to the EOR process application.

4.2 Factors Affecting the Performance of Cyclic CO_2 Injection

Various researchers have investigated the important parameters affecting the performance of the huff 'n' puff process and in the process they have also come up with some notable production-response trends that are characteristic of this process.

Monger and Coma (1988) carried out a laboratory-scale evaluation of the CO_2 huff 'n' puff process (refer to Figure 4.1 for a schematic of the experimental setup) for application in light oil reservoirs and identified the factors that affected the process performance in the laboratory. These results were then interrelated to field results to formulate a coherent, more complete, picture of which important factors affect a favorable field performance. The lab studies consisted of continuous and cyclic CO_2 coreflooding experiments using 32 ° API stock-tank oil and watered-out Berea sandstone cores; a total of 32 experiments were completed. The results from these coreflooding experiments led to the identification and the assessment of the following performance-affecting factors:

1. Mode of application: the experimental results using the watered-out Berea sandstone cores showed an average incremental oil recovery of 7%ROIP over the waterflooding phase with an average total utilization factor of 5.8Mscf/bbl. This indicated that the huff 'n' puff process was indeed effective at recovering residual oil after waterflooding. One of the parameters that were varied in the coreflooding experiments was the run pressure and the results suggested that conducting the process under immiscible conditions (see Figure 4.2) might be more favorable owing to the fact under those conditions a larger volume of CO_2 is injected resulting in oil production occurring earlier and more extensive, and with an accompanied higher CO_2 retention.
2. Amount of CO_2 injected: another variable that was investigated was the CO_2 slug size and its effect on oil recovery. They found that there was a linear relationship between the amount of CO_2 injected and the incremental oil recovery; both under immiscible as well as miscible conditions (see Figures 4.3; also visible in Figure 4.7 from Thomas & McClure's work). However, the total recovery efficiency was significantly less at miscible conditions (17.5%) as compared to that measured at immiscible conditions (41.3%) on both a mass (gmol) and a volume (reservoir pore volume) basis. The implication of these results was that a disadvantage of the miscible application might be the accompanying reservoir contraction with pressure increase.
3. Soak period: To investigate the importance of a soak period on the total oil recovery, coreflooding experiments with no soak period were conducted and compared to a similar one that did include a soak period of 10 hours. The experimental results indicated that a soak period was necessary to obtain the maximum ultimate oil recovery since the inclusion of a

soak period led to an increase in the total recovery of 10%OOIP. Unfortunately, due to perceived scaling problems the experimental results could not be extended to the field scale.

4. Aquifer influx: the effect of aquifer influx was simulated through the introduction of additional water during the back production stage resulting in additional oil being recovered. The most probable reason for this is the additional energy that an aquifer drive added to the oil production phase.

In the same study 14 field cases were also evaluated for the most pertinent factors affecting the huff 'n' puff field performance. In general, 6 to 16 MMscf of CO_2 was injected during the initial phase at a rate of several barrels per minute, followed by a shut-in period of 18 to 25 days after which the wells were placed on production. These field results are discussed in a dedicated paragraph to follow.

1. Pay zone thickness: in their evaluation of the field results a positive correlation was found between the stimulation ratio and the net pay or the perforation interval.
2. Reservoir oil viscosity: the stimulation ratio also improved slightly with a decrease in the reservoir oil viscosity making the case for the positive role played by viscous fingering of the injected gas in the huff 'n' puff process.
3. Reservoir pressure: a weak correlation was found that implied that as pressures neared the minimum miscibility pressure (MMP) this led to a slight impairment in both the utilization and stimulation factor. This phenomenon is supported by the occurrence that the displacement experiments performed at lower pressure performed better than those done at a higher run pressure. In a subsequent study Monger *et al.* (1991) conducted coreflooding experiments resulting in additional support for the hypothesis that a well-distributed initial gas saturation favorably affects huff 'n' puff performance. Figure 4.4 summarizes the aforementioned experiments in which a live oil composition was used with a bubblepoint pressure of 3,300 psig. The results clearly indicate that the cyclic CO_2 recovery increased with decreasing run pressure.

Thomas *et al.* (1990) conducted laboratory and numerical experiments that indicated that the presence of a gas cap, gravity segregation and higher initial oil saturation favorably influenced the huff 'n' puff performance. Interestingly, their results highlighted the benefit of gravity override in the huff 'n' puff lab experiments: the lower density CO_2 migrated along the top of the core during the huff stage which resulted in the bypassing of oil with deeper

penetration of the injected CO_2. The improved recovery was thought to be the result of a larger oil volume being contacted by the gas.

The literature up to this point had been scarce as to instances of application of the huff 'n' process in low pressure or pressure-depleted reservoirs. This kind of application was highlighted by Monger *et al.* (1991) who combined laboratory coreflooding experiments with evaluations of 65 single-well field tests. In the experiments, watered-out cores were used at lower pressures to assess the immiscible recovery of light oil during the huff 'n' puff application. The results revealed that the application of huff 'n' puff at immiscible conditions was able to recover up to 18.0% waterflood residual oil with a utilization factor of 1.55 Mscf/bbl and a production profile that was very similar to those of experiments at higher pressures. According to their experiments the lower-pressure results reveal two trends with pressure, namely that as pressure is lowered the retention of CO_2 increases and the gas utilization improves. The best first-cycle response were adjusted for slug size and incorporated into Figure 4.5 showing smooth improvement in CO_2 utilization factor as the pressure was decreased and the process neared immiscible conditions, whereas the recovery efficiency improved as the process became more miscible.

Additionally, they also conducted experiments using impure CO_2 to investigate its potential use. The experiments with impure CO_2 (a mixture of 45 mole% CO_2 and 55 mole% methane) were aimed to show the expanded sourcing options for injection gas, such as natural gas with an appreciable amount of CO_2, recycled gas from CO_2 flooding projects and stack/flue gas, by showing the effectiveness of using a gas mixture in the huff 'n' puff application. Their experimental results indicated the effectiveness of using a gas mixture in huff 'n' puff with the ability to recover waterflood residual oil with a gas utilization factor of up to 530scf/bbl. A second cycle was, however, needed to attain this favorable performance (see Figure 4.6).

Based on 106 single-well CO_2 huff 'n' puff tests (in 14 fields) conducted in Louisiana and Kentucky in light oil (23 to 38°API) sandstone reservoirs of which 97 indicated incremental oil, Thomas & Monger-McClure (1991) presented field performance trends and developed correlations between huff 'n' puff performance and operational variables. On average, the successful field tests recovered 10,400 barrels of incremental oil. Using the field response in terms of incremental oil, CO_2 utilization and stimulation ratio the following correlations were extracted:

1. Slug size: it was found that the mass of injected CO_2 was the best predictor of the stimulated oil production rate and the ultimate incremental recovery. They revealed a strong correlation between the mass of CO_2 injected and the production response as far as its effect incremental oil (see Figure 4.7), and the observed post-injection rise in the production rate. It was concluded that first correlation could be used as a first-approximation predictive tool assuming that the injected CO_2 contacts the oil within the targeted radius of treatment. A positive relationship between the stimulation ratio and the incremental oil produced was observed as shown in Figure 4.9. A positive correlation between mass of injected CO_2 and stimulation ratio is plotted in Figure 4.8.
2. Target treatment radius: any inferences as far as target treatment radius were limited, but the results suggested that the boundary depended on reservoir conditions. However, the evaluation of the field tests did reveal that the field response improved with the thickness of the payzone as more oil is contacted near the wellbore thus that is where process efficacy is the highest. Using the data from the 30 economically successful field tests the average migration radius for injected CO_2 was calculated to be 73 ft.
3. Soak period: based on their field test database an optimal soak period of 1 month was suggested as soaks of this duration generated as much incremental oil per foot of exposed interval as projects with longer soak periods taking into account CO_2 losses during the soak (Figure 4.10).

4.3 Operational Guidelines and Screening Criteria

Palmer *et al.* (1986) detailed the implementation of 11 CO_2 huff 'n' puff projects in 5 South Louisiana fields and came up with the following screening criteria based on these initial tests:

- High oil saturation near the wellbore.
- Reservoir pressure that was close to the minimum miscibility pressure.
- Thick payzone.
- Low reservoir permeability.
- Deep reservoirs.
- Reservoir temperature range: 185 to 240 °F.
- Oil viscosity range: 0.4 to 0.7 cp.
- Range of gas-oil ratios: 14.44 to 500 scf/stb.

Most of the above screening criteria were supported by Thomas & Monger-McClure's (1991) evaluation of 106 CO_2 huff 'n' puff field tests in light oil reservoirs, but in contrast, they concluded that even though diverse types of reservoirs appear to be amenable to CO_2 huff 'n' puff, shallow reservoirs might be more likely to be economic, and that operating below the minimum miscibility pressure might be preferred.

Mohammed-Singh *et al.* (2006) have formulated screening criteria for successful CO_2 huff 'n' puff operations based on design and production data from 16 huff 'n' puff projects implemented in the Forest Reserve oilfield, a medium heavy oil reservoir, over the past 20 years. Their screening criteria are tabulated in Table 4.1 and they have also proposed the following screening methodology:

1. Define project objectives.
2. Identify any site- or time-related advantages or disadvantages, such as favorably located gas sources or anticipated high capital investment, respectively, and near-well reservoir characteristics.
3. Develop a matrix of appropriate design and/or operating strategies for the specified objectives.
4. Optimize the objectives.
5. Explore feasible alternative improvements, such as the application of foam.
6. Develop project-specific screening criteria within the context above.

4.4 Alternative Applications of the Huff 'n' Puff Process

Under certain circumstances the use of solely CO_2 in the huff 'n' puff process can be unduly restrictive because of either economic, transportation or corrosion problems which have led to the exploration of various alternative applications of the classic CO_2 huff 'n' puff process. These alternatives have included the use of alternative injectant gases and an alternative application as far as the cyclic nature of the process.

4.4.1 Huff 'n' Puff Using Other Types of Gas and Gas Mixtures

Shayegi *et al.* (1996) conducted an experimental study in which the cyclic gas injection using pure CO_2, methane, nitrogen and mixtures of these gases with CO_2 was evaluated through immiscible gas displacement experiments using consolidated sandstone cores that contained waterflood residual oil saturation. In a typical experiment, two cycles of gas injection were

employed with a soak period of 10 hours in between. The two cycles were performed in a similar manner for consistency's sake.

Their experimental investigation concluded the following:

1. Cyclic injection of pure gases: the CO_2 and methane displacement experiments performed comparably while the use of nitrogen recovered only about half as much oil compared to the other two gases. In all these cases, the oil recovery declined in the second cycle of injection. The oil recovery efficiencies (expressed as STB) are depicted in Figure 4.11 for comparison. Further analysis of the performance also revealed that the gas utilization factors were very similar for the CO_2 and methane experiments, but were substantially higher when nitrogen was used. They attributed this difference in gas utilization factors to the fact that nitrogen is much less compressible in comparison to CO_2 and methane. The experiments also revealed significant differences in the gas production profiles with CO_2 being steadily produced throughout as opposed to the nitrogen and methane production which was in the form of discrete bursts. In the later stages the CO_2 production was also more pronounced resulting in more CO_2 being back produced as compared to nitrogen and methane leading to the conclusion that CO_2 is much more mobile in porous media.
2. Cyclic injection of CO_2/nitrogen mixtures: the oil recovery efficiencies of the various experiments using different CO_2/nitrogen mixtures are depicted in Figure 4.12 and the results indicated that all of these experiments yielded higher first and second cycle recoveries compared to either of the pure gases with water and oil production curves that were very comparable to the pure gas cases. The only main difference was that not only was more oil recovered but that a larger portion of it was produced intermittently with water and gas.
3. Cyclic injection of CO_2/methane mixtures: the results of the experiments as shown in Figure 4.13 showed that all the experiments had combined first and second cycle recoveries that were considerably higher as compared to the pure gas experiments. Additionally, the production profiles of the CO_2/methane experiments were similar to those of the CO_2/nitrogen.

In general, they concluded that using a CO_2/nitrogen mixture yielded the best recovery efficiencies.

The above experimental results were further supported by at least one field case in which a gas other than CO_2 was used in the huff 'n' puff process. Miller and Hamilton-Smith (1998)

reported on the field tests where exhaust gas, with a composition of 87% N_2 and 13% CO_2, and rich gas (1500 BTU casing head gas) were injected in two separate areas in the Big Sinking Field of eastern Kentucky, a light oil pressure-depleted reservoir. The exhaust gas was injected into the Tom Shackelford lease well # 1 and resulted in a cumulative recovery efficiency of 1.6 MCF/bbl for a total volume of 12.3 MMCF gas injected, with a projected recovery efficiency of 0.85 MCF/bbl over a six year period. The test showed that a long soak period might be needed and that large injection volumes became erratic in their initial response pattern after the injection. Casing head gas was injected into the J.R. Cable lease well resulting in a projected recovery efficiency of 3.3MCF/bbl over a 3 year period. An average soak period of 6 weeks was used. The difference in the recovery efficiency between the two field tests was attributed to:

- Reservoir variability.
- Production increase determination method.
- Gas utilized.
- Soak period.
- Injected gas volume.
- Containment of gas in test area.

It was concluded that even though the exhaust gas showed higher recovery efficiency than the rich gas, using the rich gas as the injectant led to a significant reduction in cost per recoverable barrel.

4.4.2 Natural Gas Huff 'n' Puff

The feasibility of cyclic natural gas injection for the recovery of light oil from waterflooded reservoirs was investigated by Haines & Monger (1990) by conducting coreflooding experiments and numerical simulations. In the coreflooding experiments water-wet sandstone cores were used with 35° API light oil; the natural gas used consisted of 98.5% methane. Their results showed that average waterflood residual oil recovery for the first cycle was 19.3% and cumulatively 40.6% for two huff 'n' puff cycles with an average gross gas utilization of 5MSCF/STB. They speculated that the improved second cycle response was due to gas relative permeability hysteresis. The coreflooding results were history matched through numerical simulations which revealed that re-pressurization and gas relative permeability hysteresis effects appear to be the

important oil recovery mechanisms for natural gas huff 'n' puff. They also indicated that the incremental recovery increased proportionally to the amount of natural gas injected.

The aforementioned potential of natural gas huff 'n' puff is supported by field tests as reported on by de R.A. Lino (1994). These field tests were conducted in a light oil reservoir in the Miranga field, in the state of Bahia. Six wells were chosen for these tests based on the fact that they could be produced to an existing hub, they had a low water cut and a low oil rate. Of these six wells three displayed excellent results with an average incremental oil recovery of 3,000 barrels with a gas utilization factor of 0.5 – 4.6 MCF/bbl. Based on the field results a high gas injection rate and a thicker payzone were identified as favorable operational constraints. Additionally, some advantages of using natural gas over CO_2 in the huff 'n' puff process were proposed:

- The produced gas could be recovered in its entirety.
- There were no corrosion problems due to the absence of carbonic acid generation, and the reduction in water cut.
- Natural gas was readily available for injection.
- Absence of contamination issues at the plant.

4.4.3 Alternative Application to Cyclic CO_2 Huff 'n' Puff – Soak Alternating Gas (SAG)

Even though huff 'n' puff is effective in the near-wellbore region it may not be able to realize the benefits of a full field injection program and/or there may be added injection/production capability complications associated with the single-well application. Murray *et al.* (2001) proposed a new method, soak alternating gas (SAG), whereby CO_2 is injected and the well is shut in a similar manner to huff 'n' puff but instead of producing the from the well previously used to inject CO_2 , it is again used to inject CO_2. Production occurs from a different wellbore altogether which sets this method apart from the conventional huff 'n' puff process. This method combines the soak period of the huff 'n' puff process with the ability of continuous injection to establish some measure of mobility control (see Table 4.2 for a comparison of huff 'n' puff to SAG). Ideally, in a continuous flood bypassing is minimized and most of the CO_2 recovery mechanisms take place at the flood front but conditions are almost never ideal and bypassing will occur. To this end, the soak period would be implemented and the diffusion process would dominate until the recovery mechanisms take effect enough to allow an efficient displacement

behind the flood front. Periodically shutting in the well allows for all of the recovery mechanisms to take full effect before proceeding with the injection resulting in oil at the flood front that is as fully saturated with CO_2. Since the literature is abound with cases of application of CO_2 huff 'n' puff at sub-minimum miscibility pressures and various concentrations of CO_2 there exists the possibility of a wide range of miscibility conditions over which SAG could be applicable. Because there is a soak period duration beyond which little or no additional recovery occurs, it can be inferred that even without an oil bank at the front the relative permeability shifts attributable to swelling and water displacement due to gas still cause oil displacement without the need for additional swelling effects.

Some of the key parameters that were deemed important to the SAG performance were:

- The CO_2 injection rate: Depending on the reservoir conditions the minimum injection rate needed would be the one at which viscous fingering would occur, because only then would the application of SAG minimize the adverse effect of this phenomenon.
- The volume of CO_2 injected.
- The soak period duration: because of several cycles in SAG a meaningful concept of residence time should account for both the soak periods and the injection cycles. A very general equation allowing variation in both would be the following:

$$t_{Rk} = \sum_{i=k}^{n} \frac{\overline{x_i}}{\overline{v_i}} + t_{Si} \tag{4.8}$$

Where:

t_{Rk} = the residence time of the CO_2 in the kth region to be contacted in the SAG process during the nth cycle (with $k \leq n$).

$\overline{x_i}$ = the average path length a unit slug of CO_2 travels in the ith injection stage (equivalent to determining the aforementioned treatment radius).

$\overline{v_i}$ = the average interstitial velocity of the CO_2 slug.

t_{Si} = the soak time elapsed in the ith period.

The authors planned to conduct reservoir simulation, slim tube and coreflooding experiments to optimize the SAG process and test its viability and capability across a range of conditions.

4.5 Worldwide Applications of Huff 'n' Puff EOR

As mentioned before the huff 'n' puff process for the enhanced recovery of light oil has been applied in various reservoirs in various variations:

1. Classic CO_2 huff 'n' puff: some reported examples on the application have been:
    a. Monger & Coma (1988) evaluated 14 field tests in South Louisiana oil-bearing sands of which 9 were considered successful based on an average gas utilization factor of 1.54Mscf/bbl and average reported incremental oil recovery of 8,600 bbl. No operational issues were mentioned apart from "mechanical failures". 65 single-well cyclic CO_2 field tests were reported on by Monger *et al.* (1991) that were conducted in a pressure-depleted field in the Appalachian basin in eastern Kentucky (fractured dolomitic sandstone). On average, the field tests recovered 2,300 bbl with an average utilization factor of 2.03 Mscf/bbl (based on the 12 most successful tests); again, no operational issues were reported on. All of the aforementioned field tests were included in a later, more extensive, study by Thomas & Monger-McClure (1991) in which 106 single-well huff 'n' puff field tests were analyzed. The projects were implemented in 14 fields located in Louisiana and Kentucky and 97 of the tests showed incremental oil recovery. The tests were all performed in light oil-bearing (23 – 38°API) sandstone formations (consolidated, unconsolidated and/or dolomitic); the successful tests are summarized in Table 4.3. It was mentioned in their report that several operators improved oil production by opening wells on a small choke thereby increasing backpressure on the wells, while in one field project CO_2 breakthrough during the soak period was observed. It was speculated that it had traveled through fractures to the offset producer. Management of offset wells was therefore recommended whenever migration of the injected gas beyond the targeted treatment radius might be an issue in highly fractured reservoirs.
    b. Twenty-eight huff 'n' puff projects in Texas were presented and discussed by Haskin & Alston (1989); the tests were performed in gulf coast Miocene reservoirs in east and south Texas that contained light oil (23 – 30 °API). The reported average incremental oil recovered was 1,350 bbl with an average CO_2 utilization factor of 3.58 Mscf/bbl. No specific operational issues were reported.

c. Mohammed-Singh *et al.* (2006) summarized 20 years of design and performance data on sixteen CO_2 huff 'n' puff projects in the Forest Reserve field, Trinidad & Tobago. The oilfield in question contains multiple, stacked, complex deltaic sandstone reservoirs which are solution gas driven with some aquifer influx; the oil contained in these reservoirs was qualified as a medium oil (14 – 25 °API). The average incremental recovery ranged from 1,400 to 18,000 bbl while the average CO_2 utilization was between 5 – 139Mscf/bbl. It was reported that many wells that were gravel packed showed increased sand production while the wells showing the best response to injection were in down-dip locations and may have benefited from aquifer influx and gravity drainage during the puff phase. "Mechanical difficulties" were experienced in 5 wells.

d. The latter reference also contained an extensive overview of worldwide CO_2 huff 'n' puff field trials with tests conducted in US light oil reservoirs summarized in Table 4.4. The field tests were mostly conducted in sandstone reservoirs with the total injected CO_2 volume ranging from 1 to 210 MMSCF (the average injected CO_2 volume was 20 MMSCF) with an average soak period of 20 days. The huff 'n' puff field trials recovered incremental oil in the range of 3 to 180,000 STB with an average incremental recovery of 14,000 STB of oil. Most of the reservoirs had undergone some waterflooding prior to the start of the huff 'n' puff field trial and on average, the stimulation ratio in response to the CO_2 injection was 5.

2. Huff 'n' puff using a gas mixture: Miller & Hamilton-Smith (1998) summarized the successful application of cyclic gas recovery using a gas mixture (exhaust gas, i.e. N_2/CO_2 mixture) in the Big Sinking field of eastern Kentucky. The exhaust gas increased the production six times over the initial production rate with an average utilization factor calculated over 2 years of 0.85 Mscf/bbl. Within days of injection the gas had channeled to offset wells through a natural fracture trend requiring those wells to be shut in. The exhaust gas was generated using propane and at the time the cost per incremental barrel was calculated to be $2.35/bbl with an estimated investment payback period of 10 months.

3. Hydrocarbon gas huff 'n' puff:

   a. The previous reference also contained a summary on the use of rich gas (casing head gas) in the cyclic gas recovery of oil. The projected recovery was reported as 3.3

Mscf/bbl over a 3-year period. The casing head gas was gathered from other wells in the field in conjunction with a compressor driven by an electric motor run with casing head gas. The calculated cost per incremental barrel was $1.65/bbl and an estimated payback period of 5 months.

b. De Lino (1994) presented an extended evaluation of natural gas huff 'n' puff tests in the Miranga field, Bahia, Brazil. Three of the six wells involved displayed excellent results with an average incremental oil recovery of 3,000 barrels with a gas utilization factor of 0.5 – 4.6 MCF/bbl. No operational difficulties were reported, but local availability of natural gas and moderate to high injection pressures were proposed.

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Table 4.1: CO_2 Huff 'n' Puff Screening Criteria (Mohammed-Singh *et al.*, 2006)

Reservoir Parameter	Light Oil Reservoir	Medium Oil Reservoir	Heavy Oil Reservoir
Oil viscosity (cp)	0.4 – 8	32 – 46	415 – 3,000
Oil gravity (°API)	23 – 38	17 – 23	11 – 14
Porosity (%)	13 – 32	25 – 32	12 – 32
Depth (ft)	1,200 – 12,870	2,600 – 4,200	1,150 – 4,125
Thickness (ft)	6 – 60	36 – 220	200
Permeability (mD)	10 – 3,000	150 – 388	250 – 350

Table 4.2: Comparison of CO_2 Huff 'n' Puff to SAG (Murray *et al.*, 2001)

CO_2 Process:	Advantages	Disadvantages
CO_2 Huff'n'Puff	1. Relatively low capital investment with a quick payout. 2. High CO_2 utility (BBL/MSCF) 3. Operates best in conditions of low miscibility: process is aided by viscous fingering and gravity segregation. 4. Does not require high CO2 purity: process is aided by dilution with nitrogen or methane. 5. Operates on both physical displacement and extraction mechanisms: can work equally well in either forward or reverse direction. 6. Can be used where communication between wellbores does not exist. 7. Relative permeability to oil increases with swelling and presence of CO_2 gas	1.Relatively low recovery with respect to continuous flooding or WAG. 2.Operates in a relatively narrow range to optimize miscibility through changes in reservoir pressure.
CO_2 SAG	1. Better mobility control than continuous flooding. 2. Operates in conditions of poor water injectivity. 3. Maintains the transition zone at the flood front: maximizes physical displacement mechanism. 4. Maximizes the swelling of bypassed oil near the flood front, not away from the flood front. 5. Maximizes miscibility near the flood front and the contribution of bypassed oil to the transition zone. 6. Minimizes bypassing at pore level 7. Operates over a full range of miscibilities. 8. Uses all the mechanisms of continuous CO_2 flooding and huff'n'puff to optimize recovery. 9. All mechanisms used by SAG are already proven in the field.	1. Method has not yet been tested although its mechanisms have been used for either continuous flooding or huff'n'puff. . 2. Effect of gravity segregation may reduce recovery if tendency for viscous fingering is low. 3. May take longer to recover oil than a continuous flooding or WAG process. 4. Requires large volume of CO_2. 5. Asphaltene deposits can lower permeability

Table 4.3: Summary of 97 Huff 'n' Puff Field Tests (after Thomas & Monger-McClure, 1991)

RESULTS OF SUCCESSFUL TESTS									
						Production Rates			
Field	Number of Tests	Incremental Oil (STB)	CO_2 Utilization (Mscf/STB)	Reservoir CO_2 Utilization (res ft^3/STB)	Stimulation Ratio	Pre-CO_2 Oil* (B/D)	Pre-CO_2 Water* (B/D)	Post-CO_2 Oil** (B/D)	Post-CO_2 Water** (B/D)
A	1	3,233	2.67	7.6	1.7	19	171	29	164
B	2	6,148 to 11,410	1.45 to 2.73	7.0 to 13.2	4.2 to 4.7	25 to 31	255 to 486	52 to 86	237 to 272
C	1	29,830	0.29	1.54	2.1	47	47	84	116
D	4	5,516 to 14,863	0.91 to 1.87	2.6 to 5.5	4.9 to 11.2	13 to 18	971 to 1,281	64 to 250	167 to 999
E	9	2,612 to 11,051	0.72 to 2.68	2.2 to 33.8	1.6 to 3.7	9 to 53	76 to 441	18 to 88	19 to 241
G	66	321 to 6,326	0.62 to 2.14	90 to 309	1.4 to 6.4	1 to 70	4 to 397	2 to 96	4 to 384
H	1	12,115	0.71	5.2	1.5	54	20	74	32
I	1	9,118	0.71	1.9	2.2	72	31	83	161

*Average rate for 6 months before CO_2 huff 'n' puff test.
**Average rate during first month of CO_2 huff 'n' puff response.

Table 4.4: Summary of Worldwide CO_2 Huff 'n' Puff Field Trials (after Mohammed-Singh, 2006)

SPE paper	27677	15502	15502	15502	15502	15502	15502	15502	15502	15502	15502	15502
Field	Big Sink'g	Magnet	Picket Ridge	Field C	Field D	Withers N.	Field F	Thompson	Field I	Field J	Field K	W Col.
Basin	Appalachian	Withers									Manavel	
Province	Kentucky	Texas	Texas	Texas	Texas	Texas	Texas	Texas	Texas	Texas	Texas	Texas
Country	USA	USA	USA	USA	USA	USA	USA	USA	USA	USA	USA	USA
Formation		Magnet W	Picket Ridge					Frio			Olig	S Andres
Depth (ft)	1300	5500	4570	4900	4650	5250	5250	5200	7756	4100	5000	2600
Thickness (ft)	60	21	7	12	9	8	8	25	15	15	?	?
Porosity (%)	13	23	30	31.8	31	25	25	27	?	30	30	30
Permeability (mD)	19	1700	1200	534	350	450	400	500	15	500	1000	560
Sw Current (%)	50											
Pressure initial (psi)	400											
BHP (psi) current	150	1310	930	1430	1350	860	1030	1540	1200	750	900	500
Temperature (°F)	68	154	138	155	150	150	150	153	175	149	149	116
Oil gravity (° API)	38	26	25	24.4	23	25.7	25.7	25.2	37	25	26	30
Oil viscosity (cp)		2.3	2.5	4.6	3.2	2.5	2.9	2.7	1.6	4.4	4.2	8
Transmissibility(mDft/cp)		15522	3360	1393	984	1440	1103	4630	141	1705		
Produced WOR	90%	9-24	12-16	24-108	72	12-100	6.1	1.75	0.3	0	15-99	45536
Pre-CO_2 oil rate (bbl/d)		16-86	23-27	3-41	12	12-60	54	12	21	56	9-65	12-30
% Primary Recovery												
So (start of cyclic CO2)		73	80	68	69	80	75	73	?	85	?	?
Type of reservoir	WD											
# of wells / # treatment	240/290											
CO2 Util'n (Mcf/bbl)	1.1	1.1	8.2			2.8	10.2				2.4	10.2
Project Success	Success											
Incremental oil (STB)	180000	3697	122	0	0	1766	490	3	0	0	1656	391
CO^2 injected (MMSCF)	210	4	1	8	5	5	5	4	4	4	4	4
Days of soak	10	12	7	25	20	17	17	36	23	23	21	13
Note: WF = water flood, DD= depletion drive, swd= strong water drive, wwd= weak water drive: LA & KY = Louisiana and Kentucky												

Table 4.4 (Continued): Summary of Worldwide CO_2 Huff 'n' Puff Field Trials (after Mohammed-Singh, 2006)

SPE paper	18977	20208	20208	20208	20208	20208	20208	20208	20208	20208	20208	16720
Field	Paradis	West Cote	b	c	d	e	f	g	h	I	k	Timbalier
Basin		Blanche Bay		Lake Barre					Bayou Sale	Lafitte		
Province	Louisiana	Louisiana	LA & Ky	Louisiana	LA & Ky	LA & Ky	LA & Ky	LA & Ky	Louisiana	Louisiana	LA & Ky	Louisiana
Country	USA	USA	USA	USA	USA	USA	USA	USA	USA	USA	USA	USA
Formation	Main py	Minnelusa	Sand	Up M	Sand	Sand	Sand	Sand	St. Marry	Sand	Sand	
Depth (ft)	10200	8140	10330	12870	4909	1200-3000	6248	1300	10060	8900	9837	4878
Thickness (ft)		21	46	20-50	12-17	6-24	7-35	34-58	30	na	15-34	
Porosity (%)	28	29	28	25	32	32	32	13-16	31	27	24	32
Permeability (mD)	1033	322	1033	139	2500	3000	300-500	10	500	250	252	500-2500
Sw Current (%)												25
Pressure initial (psi)												2390
BHP (psi) current		3847	2406	2500	2235	560-1400	2900	100	1795	3947	5100	2235
Temperature (°F)		185	212	240	138	80-100	166	68	206	185	192	138
Oil gravity (° API)	38	23-38	23-38	33	23-38	23-38	23-38	23-38	23-38	34	23-38	26
Oil viscosity (cp)	0.5	1.3		0.4						0.7		
Transmissibility(mDft/cp)		5202										
Produced WOR		9	15.6	1	71	8.3		5.5	0.37	0.43		99%
Pre-CO_2 oil rate (bbl/d)	23	19	25-31	47	13-18	9-53		1-70	54	72		15
% Primary Recovery												18
So (start of cyclic CO2)												34-60
Type of reservoir	tertiary	WF	WF	DD	SWD	SWD	SWD	DD	WWD	SWD	DD	b/water
# of wells / # treatment	11	1	2	3	4	9	2	66	1	1	3	2
CO2 Util'n (Mcf/bbl)	1.9	2.7	1.5-2.7	0.3	0.9-1.9	0.72-2.68		0.6-2.1	0.7	0.71		1.1-3.2
Project Success	Success											Success
Incremental oil (STB)	27000	3233	6148-11410	29830	5516-14863	2612-11051		321-6326	12115	9118		14000
CO^2 injected (MMSCF)	18											23
Days of soak	21	31	19-21	25-33	28-181	28-63	20-23	Jul-38	47	17	16-54	4-7 weeks
Note: WF = water flood, DD= depletion drive, swd= strong water drive, wwd= weak water drive: LA & KY = Louisiana and Kentucky												

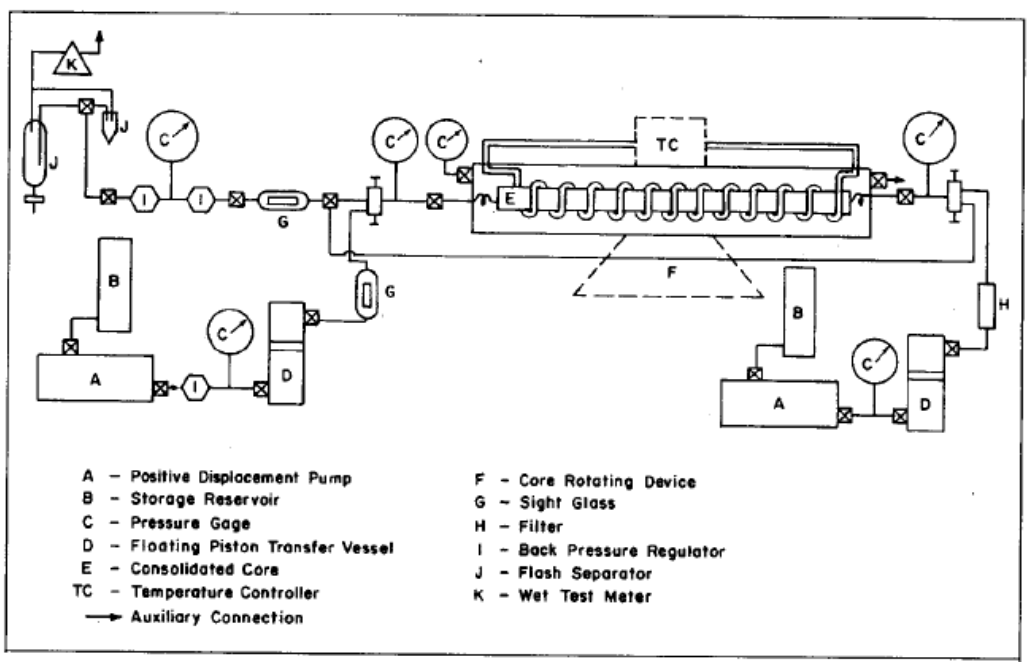

Figure 4.1: Experimental Setup for CO_2 Flooding (Monger and Coma, 1988)

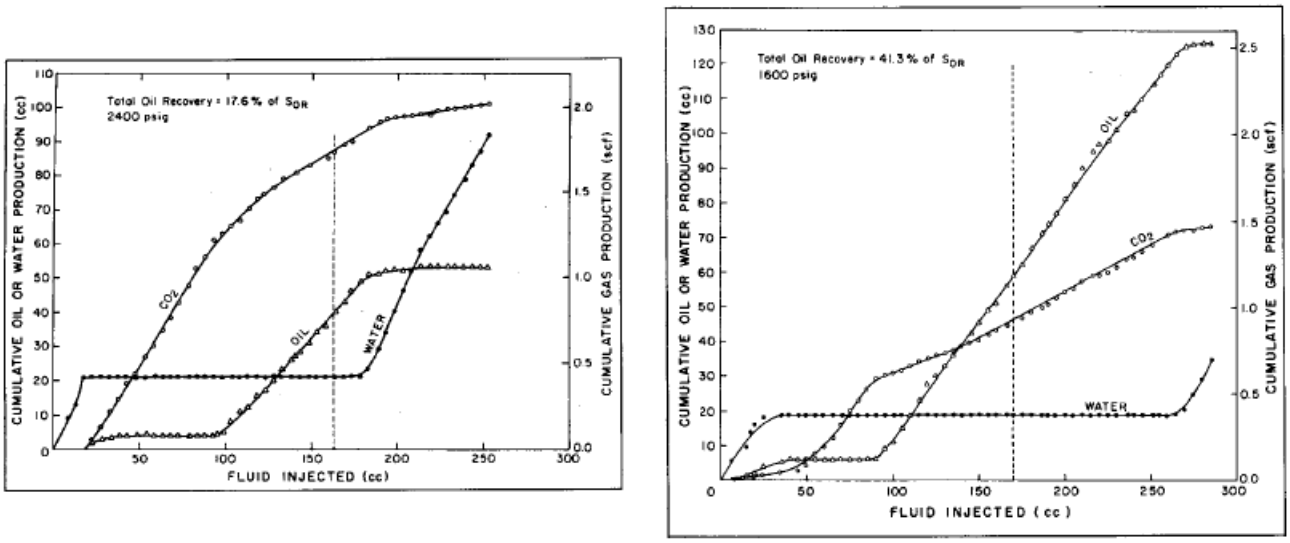

Figure 4.2: Production Profile of Cyclic CO_2 Flooding at 2,400 psi (left) and 1,600 psi (right) (after Monger and Coma, 1988)

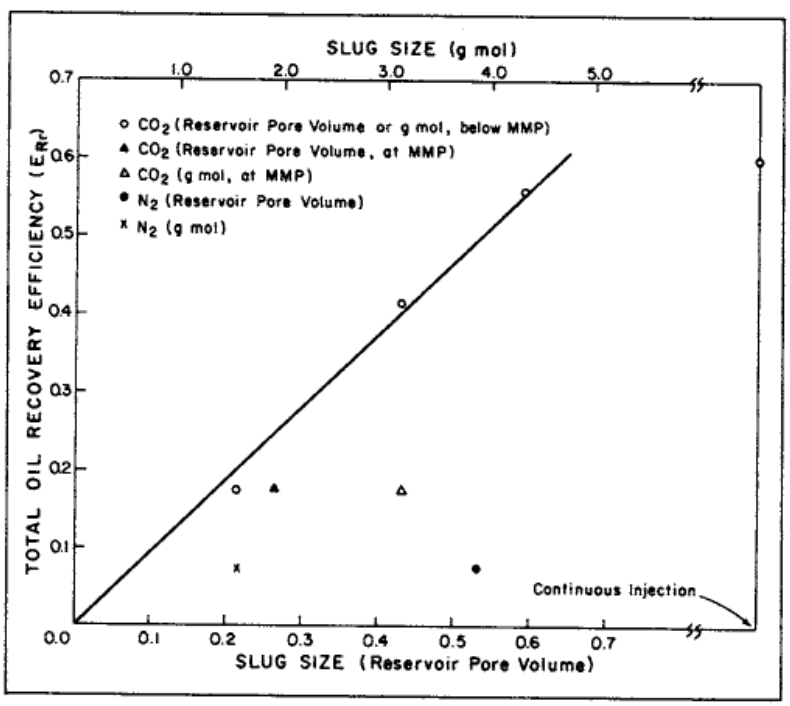

Figure 4.3: Relationship between Amount of CO_2 Injected and Total Recovery (Monger and Coma, 1988)

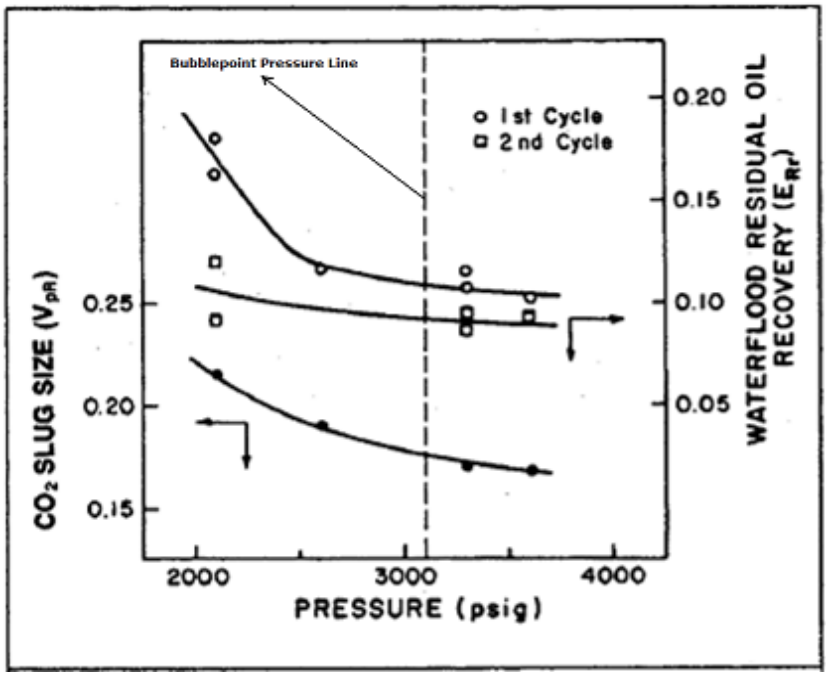

Figure 4.4: The Effect of Initial Gas Saturation on Huff 'n' Puff Performance (Monger *et al.*, 1991)

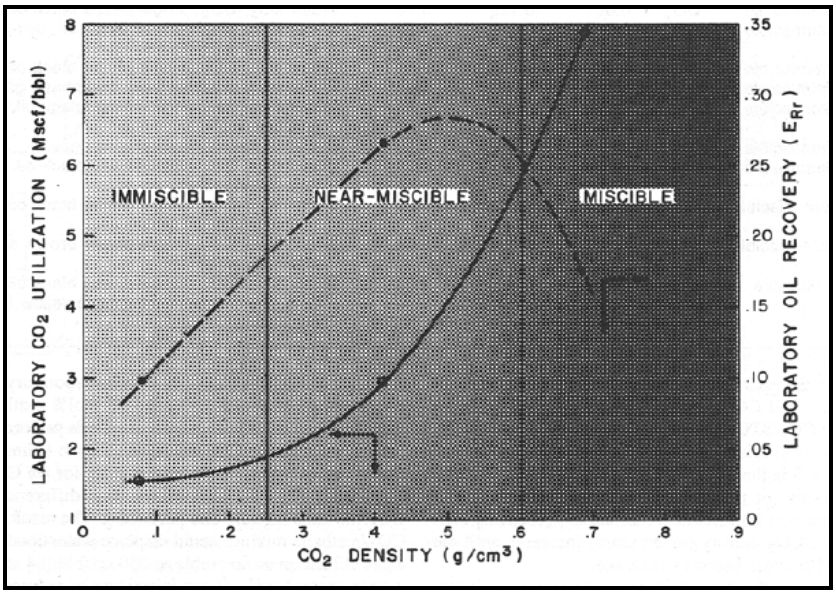

Figure 4.5: Correlation between CO_2 Utilization and Miscibility Inferred from Coreflooding Experiments (Monger *et al.*, 1991)

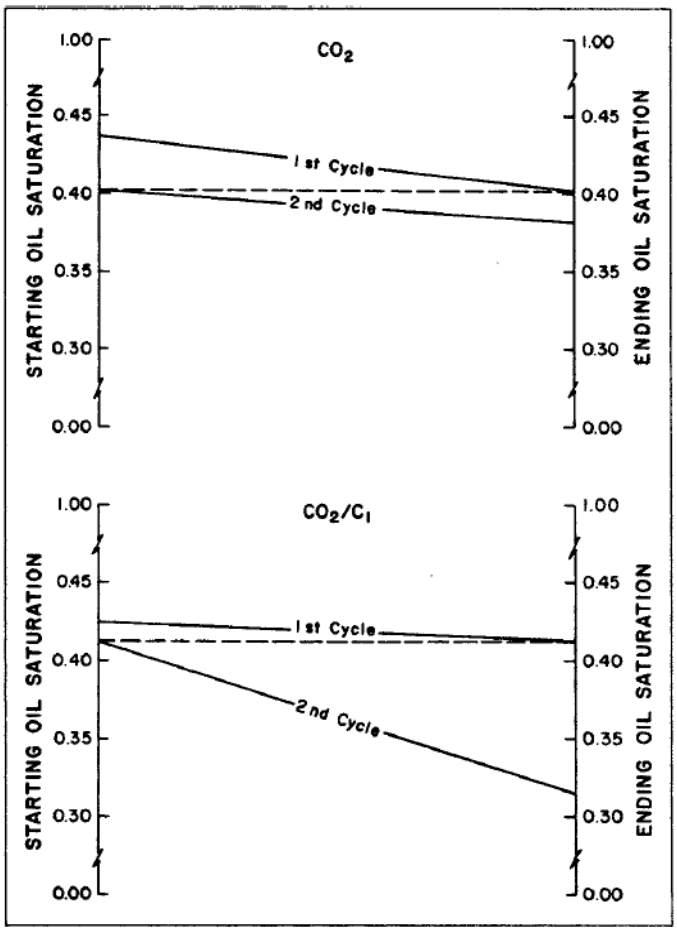

Figure 4.6: The Effect of Repeated Cycles on Huff 'n' Puff Performance using CO_2 and Gas Mixture (Monger *et al.*, 1991)

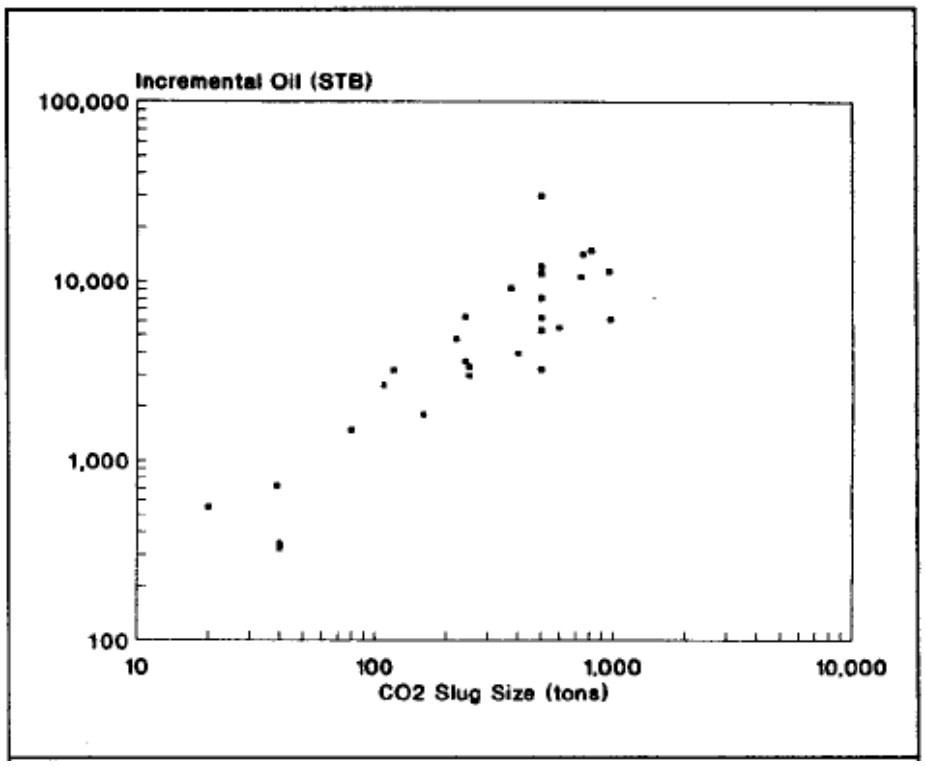

Figure 4.7: Correlation between Injected Mass of CO_2 and Incremental Oil (Thomas & McClure, 1991)

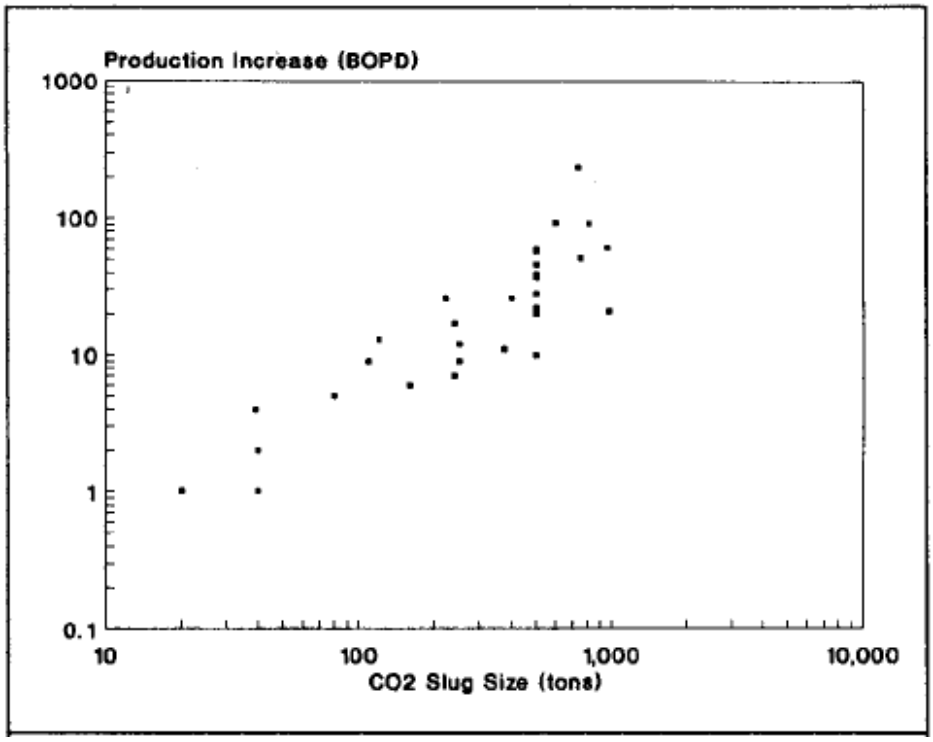

Figure 4.8: The Effect of Injected Mass of CO_2 on Stimulation Ratio (Thomas & McClure, 1991)

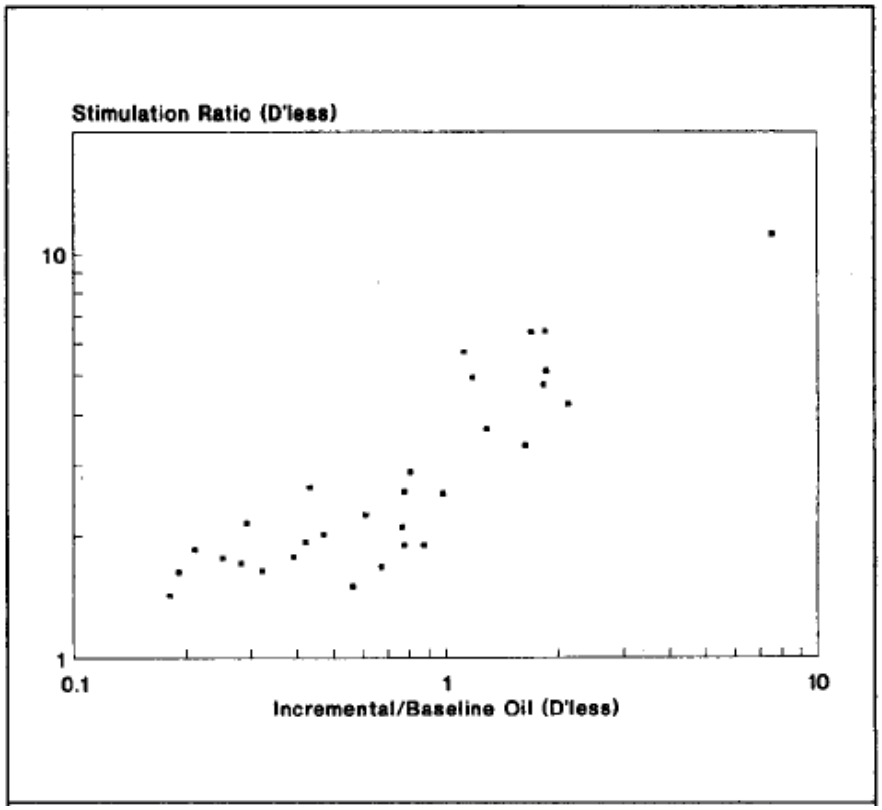

Figure 4.9: Relationship between Stimulation Ratio and Incremental Oil due to CO_2 Huff 'n' Puff (Thomas & McClure, 1991)

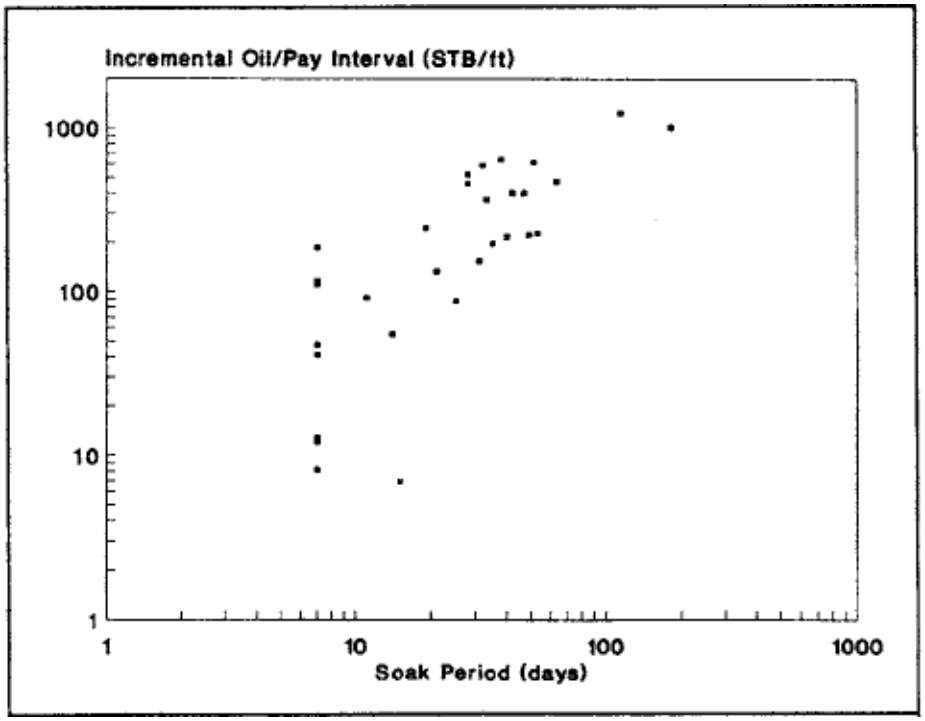

Figure 4.10: Correlation between Soak period and Incremental Oil per Pay Interval (Thomas & McClure, 1991)

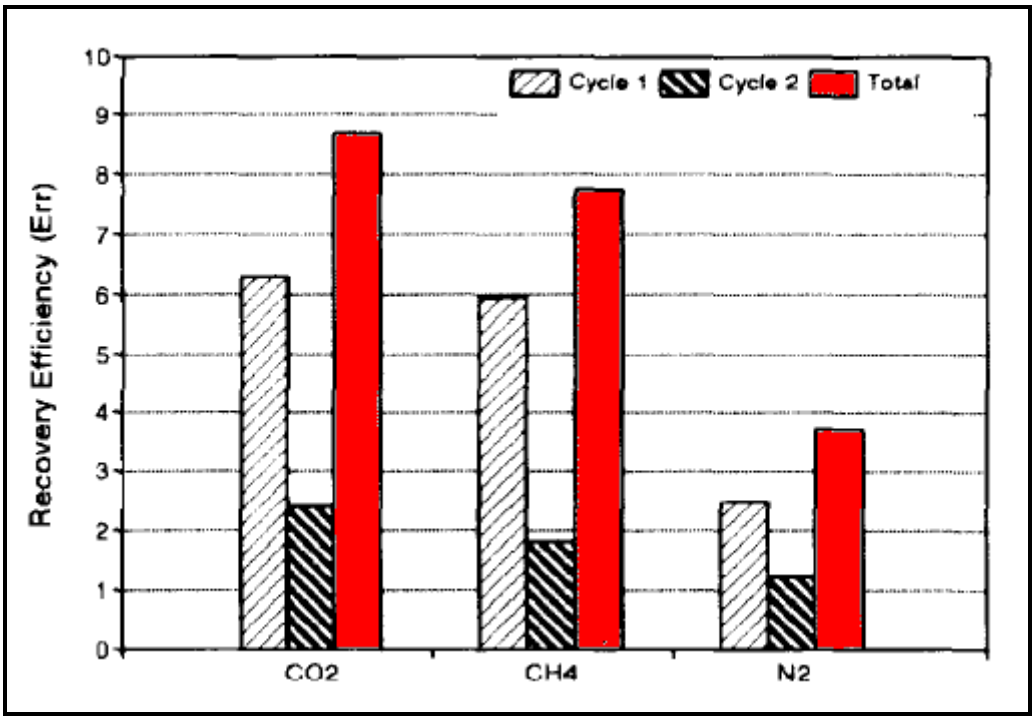

Figure 4.11: Average Recovery Efficiencies of the Pure Gas Huff 'n' Puff Experiments (after Shayegi *et al.*, 1996)

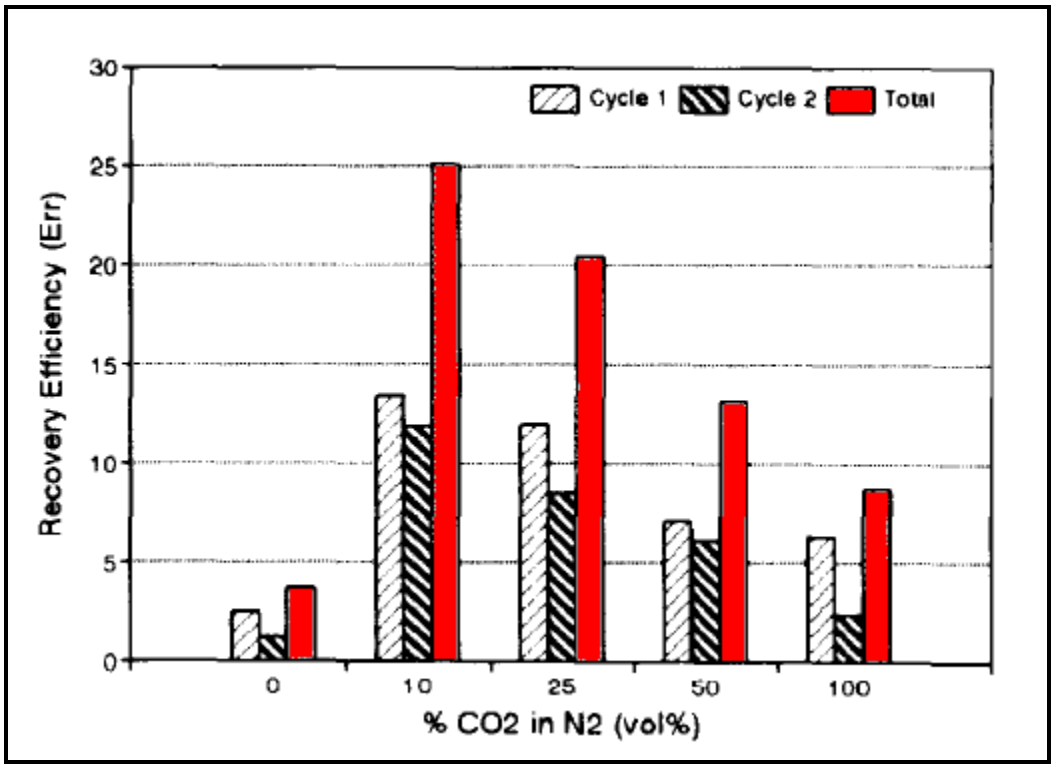

Figure 4.12: Average Recovery Efficiencies of the CO_2/Nitrogen Huff 'n' Puff Experiments (after Shayegi *et al.*, 1996)

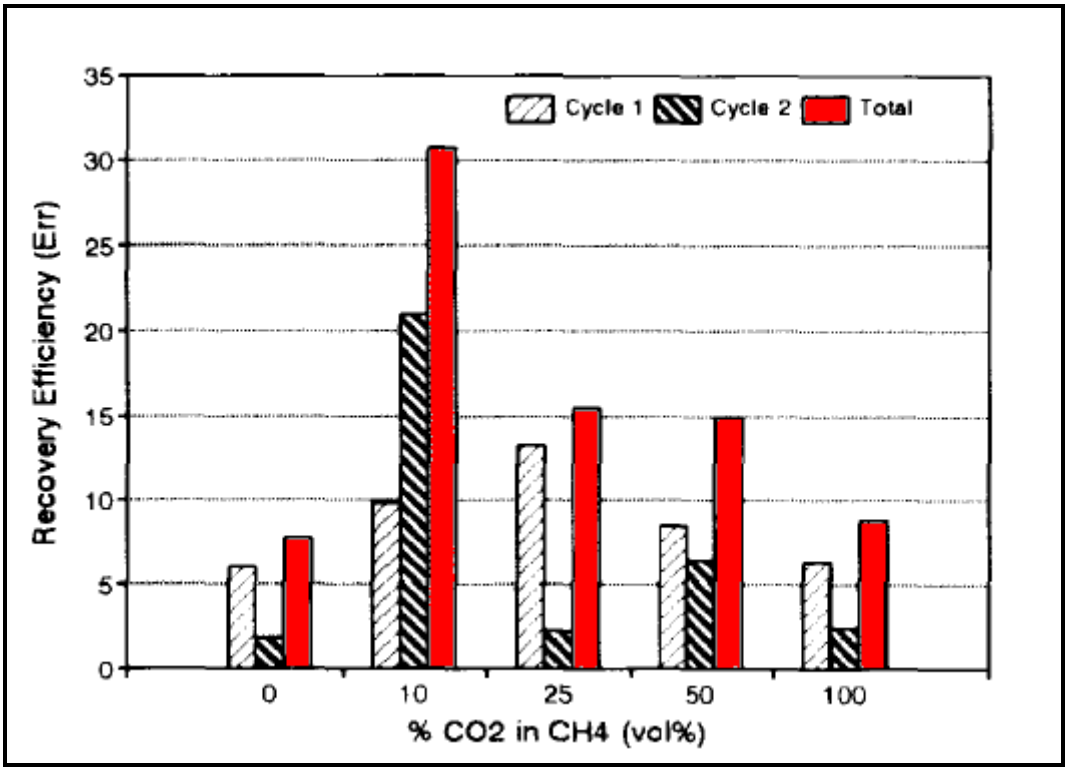

Figure 4.13: Average Recovery Efficiencies of the CO_2/Methane Huff 'n' Puff Experiments (after Shayegi *et al.*, 1996)

5.1 Literature Review on Hydrocarbon Gas Injection

5.1.1 Introduction – Summary of the Process

Hydrocarbon gas injection has been used for IOR for many years by the industry. Its use in the secondary and tertiary mode can increase the oil recovery.

Egermann *et al.* (2006) postulated that relative to water injection, the injection of hydrocarbon gas is associated with higher microscopic displacement efficiency because of the low interfacial tension (IFT) between oil and the injected gas. Even if the gas were to be injected under immiscible conditions, the mass-transfer between the oil and gas phase would lead to lower IFT as compared to waterflooding thereby making it an effective oil recovery process. They identified the following mass-transfer mechanisms that are dependent on the nature of the injected gas and the oil in place (Stalkup, 1984; Bardon *et al.*, 1989 & 1994):

1. Condensing gas drive – occurs when a gas rich in intermediate components is injected. Miscibility is reached through the condensation of the intermediate components into the liquid phase.
2. Vaporizing gas drive – miscibility is achieved through the stripping of intermediate and heavier intermediate components from the liquid into the gas phase until it is rich enough to become miscible with the liquid phase.
3. Condensing/vaporizing gas drive – in the case a rich gas is injected condensation of the intermediate components occurs at the gas front while vaporization of the heavy intermediate components can be observed behind the front.

Regardless of the mass-transfer mechanisms at work hydrocarbon gas injection can be applied at various stages of production in the reservoir.

5.2 Factors Influencing Performance

Following are the important factors that that impacts the performance of hydrocarbon gas injection recovery process:

1. Interfacial tension effects: Thomas *et al.* (1996) mention the following equation describing the relationship between the capillary pressure, P_{cap}, to the interfacial tension, σ, and pore diameter, D – $P_{cap} \propto \frac{\sigma}{D}$. According to the latter, in order to displace oil from a pore the pressure drop that needs to be applied must be at least as large as the capillary pressure

influence, because only then will the injected fluid be able to access the oil contained in the pore. As is evident, the capillary pressure would decrease if the interfacial tension decreased and/or the pore diameter increased. If the gas/oil IFT were lower than the water/oil IFT it would stand to reason that smaller pores could be accessed by the injected gas than was previously possible with injected water.

2. Mobility effects: they also identify mobility effects to be important in the recovery process of oil, because the common fractional flow describing the flow of oil and the displacing fluid is as follows – $f_d = \frac{1}{1+\frac{1}{M}}$, with $M = \frac{\mu_o}{\mu_d}\frac{k_{rd}}{k_{ro}}$ and $M \propto \frac{\mu_o}{\mu_d}$. If dispersion is neglected they postulate that the length of a viscous finger is proportional to the viscosity ratio: $\log(L) \propto \frac{\mu_o}{\mu_d}$. The occurrence of viscous fingering, however, is not only the result of an adverse viscosity ratio but can also result from the establishment of a porous media induced path of least resistance.
3. Gravity effects: in their screening study Thomas *et al.* (1996) also recognize the importance of gravity effects in especially thicker reservoirs and vertically oriented gasfloods where the buoyancy effects overrides any adverse viscosity ratio. They also refer to Stalkup's equation for the critical rate in vertical systems, $v_{v/g} = \frac{\upsilon\mu}{k_o \Delta\rho g}$, that shows the four regimes pertaining to levels of the viscous to gravity ratio. According to the latter, in order for a horizontal flood to be effective the viscous to gravity ratio must exceed a certain value to reduce the serious effects of gravity override. This can be achieved by viscous fingering due to a lower gas-oil density difference. At the low end of the injection rate gravity override will occur while at the high end bypassing and displacement inefficiency takes effect.
4. Wettability: mass-transfer mechanisms can be enhanced in oil-wet reservoirs due to oil film flow (Stoifferis & Boibien, 1995; Nicolle *et al.*, 1998).
5. Reservoir heterogeneity: especially in terms of permeability, fracturing and vertical continuity it can severely affect the sweep efficiency of the reservoir. However, reservoirs that have a low permeability and have experienced poor recovery and low injectivity might be good candidates for gas injection under secondary conditions (Li *et al.*, 2002).

6. Timing of the gas injection: implementing gas injection in secondary or tertiary mode might make the difference in order to optimize both the oil production rates as well as the ultimate recovery (Jerauld, 2000).

5.3 Applications in Offshore Reservoirs

The hydrocarbon gas injection has been extensively applied in North Sea reservoirs starting as early as 1971 in the Ekofisk field (Lake *et al.*, 2008; Awan *et al.*, 2006). In Awan's survey of EOR applications in the North Sea 18 projects were summarized that used hydrocarbon gas as the injectant gas of choice in their respective EOR application of which 6 projects involved hydrocarbon gas injection in the miscible mode (see Table 5.1). Except for the Alwyn North in all of these projects the gas was injected updip thereby displacing the oil downdip. Thus, these projects could double as gas storage/disposal projects as well. Historically there can be many objectives for choosing hydrocarbon gas injection as an EOR method, and in the case of the North Sea projects these have been limited export capacity, as was the case in the Ekofisk and Statfjord fields, and reservoir pressure maintenance above the minimum miscibility pressure, as was the case in Statfjord. Although not many of the operators made mention of the total incremental recovery due to miscible displacement, it varied between 1.4 to 3.3%STOOIP.

Based on their review of the literature, Awan *et al.* (2006) identified possible reasons for the limited or restricted use of miscible hydrocarbon gas injection for EOR purposes, namely whether selling the gas would be more profitable or not, the depth, thickness and dip of the formation (if the reservoir is thin then it should be dipping), the occurrence of permeable streaks might be detrimental to gas injection, and the proper oil properties, such as a gravity above 23°API, an oil viscosity below 3cp, and a high percentage of light components.

5.4 Operational Guidelines and Screening Criteria

Thomas *et al.* (1996) conducted an experimental investigation of the effects of IFT, viscosity to gravity ratio and wettability on gasfloods in order to formulate screening criteria for EOR by gas injection. Coreflooding experiments were performed in which different gas injection scenarios in four types of reservoirs were simulated: miscible as well as near-miscible mode corefloods (horizontal and vertical), using sandstone as well as carbonate cores. Based on the results from these corefloods the following was deduced:

1. The micro-scale geology is important in determining the design of EOR strategies.
2. The balance between IFT, gravity, mobility and microscale (core) properties must be properly evaluated for optimal exploitation.
3. Conducting a low IFT (i.e. lean gas) injection scheme showed a significantly better response compared to high IFT (i.e. rich gas) injection.
4. The composition of the injected gas can influence the rate and stability of displacement with better performance achieved with higher molecular weight of the C_{2+}-fraction of the injectant.
5. In very heterogeneous reservoirs mobility control was deemed to be more critical than achieving a low IFT value.

Taber *et al.* (1997) proposed screening criteria after examining data from EOR projects around the world and determining the optimum reservoir/oil characteristics. The screening criteria are based on both field results and oil recovery mechanisms and are summarized in Table 5.2.

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Table 5.1: Overview of Hydrocarbon Gas Injection Projects in the North Sea (after Awan *et al.*, 2006)

Operator	Field/Startup	Location	Reservoir	Total Predicted Incremental Recovery (%STOOIP)	Average Total Prod. (STB/day)	Enhanced Average Prod. (STB/day)	Gas Injection Efficiency (Mscf/STB)	Total Enhanced Prod. (STB)	Calculated Incremental Recovery (%STOOIP)	Result
ConocoPhillips	Ekofisk (1971)	Norway	Ekofisk (Tor)	2-3	284,696	N/A	N/A	N/A	N/A	Success
ExxonMobil	Beryl (1976)	U.K.	Upper Beryl	N/A	24,776	N/A	N/A	N/A	N/A	Success
Statoil	Statfjord (1979)	Norway	Statfjord	N/A	120,110	N/A	N/A	N/A	N/A	Success
Shell	Brent (1976)	U.K.	Statfjord (Unit 1)	1.4	2,657	N/A	N/A	N/A	N/A	Success
Total	Alwyn North (1987)	U.K.	Brent	3.3	16,712	1,641	0.8	1.509	0.3	Success
Statoil	Smorbukk (1999)	Norway	Garn	N/A	97,498	N/A	N/A	N/A	N/A	Success

Table 5.2: Screening Criteria for Miscible Hydrocarbon Gas Injection (after Taber *et al.*, 1997)

HYDROCARBON-MISCIBLE FLOODING

Description

Hydrocarbon-miscible flooding consists of injecting light hydrocarbons through the reservoir to form a miscible flood. Three different methods have been used. The first-contact miscible method uses about 5% PV slug of liquefied petroleum gas (LPG), such as propane, followed by natural gas or gas and water. A second method, called enriched (condensing) gasdrive, consists of injecting a 10 to 20% PV slug of natural gas that is enriched with ethane through hexane (C_2 through C_6), followed by lean gas (dry, mostly methane) and possibly water. The enriching components are transferred from the gas to the oil. The third and most common method, called high-pressure (vaporizing) gasdrive, consists of injecting lean gas at high pressure to vaporize C_2 through C_6 components from the crude oil being displaced. A combination of condensing/vaporizing mechanisms also occurs at many reservoir conditions, even though we usually think that one process is dominant. Immiscible criteria are given in Table 3 of Ref 1.

Mechanisms

Hydrocarbon miscible flooding recovers crude oil by (1) generating miscibility (in the condensing and vaporizing gasdrive); (2) increasing the oil volume (swelling); (3) decreasing the oil viscosity; and (4) immiscible gas displacement, especially enhanced gravity drainage with the right reservoir conditions.

Technical Screening Guides

	Recommended	Range of Current Projects
Crude Oil		
Gravity, °API	>23	24 to 54 (miscible)
Viscosity, cp	< 3	0.04 to 2.3
Composition	High percentage of light hydrocarbons	
Reservoir		
Oil saturation, % PV	>30	30 to 98
Type of formation	Sandstone or carbonate with a minimum of fractures and high-permeability streaks	
Net thickness	Relatively thin unless formation is dipping	
Average permeability	Not critical if uniform	
Depth, ft	>4,000	4,040 to 15,900
Temperature, °F	Temperature can have a significant effect on the minimum miscibility pressure (MMP); it normally raises the pressure required. However, this is accounted for in the deeper reservoirs that are needed to contain the high pressures for the lean gasdrives.	

Limitations

The minimum depth is set by the pressure needed to maintain the generated miscibility. The required pressure ranges from about 1,200 psi for the LPG process to 4,000 to 5,000 psi for the high-pressure gasdrive, depending on the oil. A steeply dipping formation is very desirable to permit some gravity stabilization of the displacement, which normally has an unfavorable mobility ratio.

Problems

Viscous fingering results in poor vertical and horizontal sweep efficiency. Large quantities of valuable hydrocarbons are required. Solvent may be trapped and not recovered in the LPG method.

6.1 Literature Review of the Air Injection, Low Temperature Oxidation Process (AI-LTO)

6.1.1 Introduction – Summary of the IOR Process

The air injection low temperature oxidation (AI-LTO) process involves the injection of air (composed mostly of 78% N_2 and 21% O_2) for the recovery of light oil in instances where hydrocarbon gas injection is limited by the cost and availability of gas. In this case, the air is used to produce flue gas through the oxidation of a small part of the oil in place (5 to 10%OOIP) and improve the recovery factor by flue gas sweeping. The availability of the injectant should allow the wide application of this process. The oxidation reactions occur at low temperature (close to the reservoir temperature) and three main regions can be distinguished (Clara *et al.*, 1999) in the reservoir during the application of this process:

1. A zone around the injector, swept by the injected air, in which the residual oil saturation is low. The corresponding reservoir oil is partially oxidized but can no longer consume oxygen.
2. A large oxidation (or combustion) zone where oxygen is consumed by the residual oil left in a very gradual manner away from the near-wellbore area. The gas formed is called flue gas and typically consists of 85% N_2, 13% CO_2 and 2% CO; the exact composition is dependent on the temperature conditions and the nature of the reservoir oil. Typical oxidation front temperatures are in the range of 400 to 800°F, but in the case when the thermal heat losses through the rock are much higher than the heat generated by the oxidation reactions at reservoir temperature and thus do not contribute to increasing the temperature, oxidation reactions can be partial with a lower carbon oxides generation occurring at a temperature close to the reservoir temperature.
3. A wide zone downstream of the oxidation zone, swept by the flue gas at reservoir temperature. However, less carbon oxides are generated by the oxidation reactions occurring at a temperature close to the reservoir temperature, and the flue gas is mainly composed of nitrogen.

In the case a high temperature thermal front is ignited a fourth zone is usually present following the oxidation zone, namely a short zone where thermal effects contribute to the formation of an oil bank which is partially being displaced by the flue gas and/or a hot water or steam front depending on the reservoir conditions. These zones are depicted in Figure 6.1.

6.2 Recovery Mechanisms

According to Turta and Singhal (2001), in order for an air injection project to be successful the oxygen use has to be complete, i.e. the injected oxygen must be consumed in the reservoir before reaching the producer for safety reasons, and spontaneous ignition, i.e. initiation of the oxidation reactions, should be easily achieved. This opinion is also offered by Clara *et al.* (1999), who state that the most of the produced oil comes from drainage in the light oil air injection recovery process. Because of the presence of the in-situ generated flue gas this process is very comparable to a classical gas injection using flue gas.

The main recovery mechanisms for AI-LTO are:

1. Flue gas sweeping.
2. Field re-pressurization.
3. Oil swelling due to the in-situ generated CO_2 and to a lesser extent the N_2.
4. Viscosity reduction by CO_2 dissolution.
5. Stripping of lighter components by flue gas.
6. Thermal effects in the case a high temperature combustion front does exist.

What sets AI-LTO apart from the in-situ combustion process as applied in heavy oil reservoirs is the fact that the latter relies on the thermal effects to mobilize the oil. Also, much higher temperatures are usually achieved (up to 1,500°F) because of the nature of the fuel and that more of it is consumed.

6.3 Field Applications of Air Injection for the Recovery of Light Oil

To date no air injection projects have been implemented in any offshore reservoirs, although feasibility studies have been carried out for possible implementation of the process in the Handil field, Makaham delta, Indonesia (Clara *et al.*, 1999). The process has been implemented in onshore reservoirs such as the commercial air injection projects in the Williston Basin of North and South Dakota (Turta & Singhal, 2001), which were all applied in dolomite reservoirs with low porosity (11 – 19%) and permeability (< 20mD) containing very light oils (oil viscosity less than 2cp). Those and similar other projects are tabulated in Table 6.1. It should be noted that the most important feature of the mentioned projects is the high reservoir temperature which would facilitate the auto-ignition process. These projects were all applied in patterns with no additional benefit from gravity drainage with some of the projects experiencing corrosion problems that

were solved by routine methods. Unfortunately, no incremental recovery was reported for these projects.

Clara *et al.* (1998) reported on the air injection project in the Horse Creek field in the south-central portion of the Williston basin, Bowman County, North Dakota. It is a light oil (32°API) non-fractured carbonate reservoir within the Ordovician age Red River formation. The air injection started in May, 1997, and reached a cumulative injected volume of 4.55BCF in December, 1997. The cumulative incremental production was determined to be 7.6MMbbls and the air requirement (estimation of the volume of oil mobilized by the oxidation front as a result from the injected air) was calculated to be 0.98Mscf/bbl. A subsequent economic evaluation of the project revealed that based on the incremental production and the actual costs associated with the installation and operation, the economic performance of the project was deemed favorable. They compared the performance of the studied project to two other air injection projects as tabulated in Table 6.2. Even though there is quite some difference in the reservoir and fluid properties the incremental recovery was very comparable and ranged from 14.3 to 16.6%.

6.4 Application Guidelines

According to Greaves *et al.* (2000) a sufficiently long residence time in the reservoir is required to completely remove all oxygen. This would be easily attained in reservoirs with fairly long well spacing. The oxygen concentration of the gas would gradually decrease with increasing distance from the injector, thus starting at the injector the displacement gases produced by the LTO reactions are composed of CO_2, CO and N_2, and vaporized hydrocarbons. The characteristic reaction zone in LTO processes is one in which the oxygen concentration steadily decreases extending over a long distance. The displacement front is either nitrogen or flue gas depending on the rate at which CO_2 is formed. Turta and Singhal (2001) also mention that the prediction performance of an AI-LTO is very similar to a nitrogen immiscible flood in that the volumetric sweep efficiency should be calculated in a similar way, while the displacement efficiency should be modified for a higher residual oil saturation in the displaced zone. They also suggest that an air-injection project should be started at the uppermost part of the reservoir and operated in a top-down mode to take advantage of gravity. A peripheral line-drive was also suggested and the same configuration was mentioned by Teramoto *et al.* (2006) to effectively control channeling of the injected air.

The proposed reservoir screening criteria are as followed (Turta and Singhal, 2001):

- Relatively homogenous reservoirs.
- Oil saturation > 50%.
- Oil viscosity > 10cp and < 30cp.
- Oil density > 45°API and < 35°API.
- Reservoir temperature > 122 °F.

In order to maximize the potential for a successful application the selection of candidate reservoirs should include the following (Fassihi *et al.*, 1997):

- Any tests to provide technical parameters should be performed over a wide range of reservoir oils and conditions.
- Process applicability should be judged given certain oil's combustibility and relevant reservoir parameters.
- Appropriate numerical models should be built to simulate lab experiments and obtain filed rate and recovery predictions.
- Field projects should be designed and operated efficiently and safely.
- Field results must be evaluated for optimization.

6.4.1 Offshore Safety Aspects

Greaves *et al.* (2000) have identified areas of possible hazard when this process is applied offshore based on an assumed typical application configuration similar to onshore. Their discussion was based on gas release rates as calculated for a typical offshore gas compression system installation of two parallel trains, and also assumes the use of two separate detection systems, one used to monitor the production and the other to monitor the compression system. The ingress of air or gas from the formation is based on release rates from a typical production wellhead valve configuration and one possibility for a major hazard would be the ingression of hydrocarbon gas into the air compression system leading to an explosion. This could occur due to ingestion after release from the installation process system. With the injection system shut down ingress would be from the well formation. An air injection system would be risky because of two possible factors: mechanical failure of the equipment during injection and mechanical failure following the ingestion of hydrocarbon gas into the air compressor. To reduce the risk it

was suggested to reposition the compressors on the platform, to install gas detection measures for safety surveillance and correctly choosing the operating mode(s) of the compressor.

6.5 Benefits Estimation

It was estimated by Stokka *et al.* (2005) that under optimal economic conditions an incremental recovery of 5% could be attained if air injection would be applied in the Ekofisk field. Fassihi *et al.* (1997) proposed a method of estimating the recovery factor in light oil air injection projects that was based on the producing gas oil ratio, GOR, of the field in question. They used the production data from the air injection projects in the Buffalo field, South Dakota, and the Medicine Pole Hills field, North Dakota, which are both producing from carbonate reservoirs, to illustrate the use of their proposed technique. It is comparable to the technique common in waterflooding in which the fractional recovery is plotted against the water oil ratio (WOR) on semilog paper to arrive at an estimate of the ultimate recovery after extrapolation. They use the same logic to estimate the ultimate recovery in gasfloods by plotting the cumulative recovery against the GOR. Figures 6.2A and 6.2B show the field-wide recovery versus producing GOR for the Buffalo and the Medicine Pole Hills fields respectively. The fairly linear trends indicate that they can be extrapolated to estimate the ultimate recovery to the economic limit for the GOR. If the trend in both fields is extended to a maximum GOR of 40 Mscf/STB then estimates for the incremental recovery would be 15.6 %OOIP for the Buffalo field and 14.2 % of OOIP for the Medicine Pole Hills field over the primary production. The latter field had an air utilization factor of about 4.2 Mscf/bbl.

References

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3. Ershaghi, I., and Omoregie, O., “A Method for Extrapolation of Cut vs. Recovery Curves,” *JPT*, **203**, February 1978.

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5. Greaves, M., Ren, S.R., Rathbone, R.R., Fishlock, T., and Ireland, R., "Improved Residual Light Oil Recovery by Air Injection (LTO Process)," JCPT, volume 39, no. 1, January 2000, pp. 57-61.
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8. Teramoto, T., Uematsu, H., Takabayashi, K., and Onishi. T., "Air-Injection EOR in Highly Water-Saturated Light-Oil Reservoir," SPE paper 100215 presented at the SPE Europec/EAGE Annual Conference and Exhibition in Vienna, Austria, 12-15 June 2006.
9. Turta, A.T., and Singhal, A.K., "Reservoir Engineering Aspects of Light-Oil Recovery by Air Injection," SPE paper 72503, SPE Reservoir Evaluation & Engineering, Volume 4, Number 4, August 2001, Pages 336-344.

Table 6.1: Various Onshore U.S. Air Injection Projects (after Turta & Singhal, 2001)

Field/Company/Country	Rock Type	Pay Thickness (m)	Depth (ft)	Temp (°F)	Injection Pressure (psi)	Porosity (%)	Permeability (md)	Oil Viscosity (cp)	Daily Oil Produced (BBL/D)	Air/Oil Ratio (scf/bbl)
West Hackberry/Amoco/Louisiana, U.S.A.	Sand	10*	3,000 - 12,000	201	–	27	300	0.9	–	–
		*Dip = 23 - 35°								
SLOSS/Amoco/Nebraska, U.S.A.		6	6,200	201	3,600	11	190	0.8	480	16,900
Medicine Pole Hills Unit/Continental/U.S.A.	Dolomite and Limestone	6*	9,500	220	4,400	17	5	0.5	600	12,000
Buffalo/Continental/U.S.A.	Dolomite	?	8,500	216	4,400	19	18	0.5	2,500	10,000
Madison CAPA/Koch Expl./U.S.A.	Limestone	?	8,600	210	4,400	11	10	0.5	–	20,000

Table 6.2: Comparison of Three Air Injection Projects (after Clara *et al.*, 1998)

	Medicine Pole Hills *	Buffalo Red River *	Horse Creek
Productive formation	Red River	Red River	Red River
Productive zone	B & C	B	D
Trapping mechanism	Mainly structural	Stratigraphic	Stratigraphic
Depth to Reservoir, ft	9500	8450	9125
Productive acreage	4877 (B-zone)	5034	3824
Average porosity, %	B : 19 , C : 15	20	16
Average permeability, mD	5	10	10-20
Average net pay, ft	18	10	20
Average water saturation, %	B : 37, C : 48	45	35
Reservoir temperature, °F	230	215	220
Initial reservoir pressure, psig	4120	3600	4000
Oil gravity, API	39	30	32
Bubble point pressure, psig	2246	300	625
Solution gas ratio, SCF/STB	525	120	205
Formation volume factor	1.40	1.16	1.21
OOIP, MMBBLS	40.0	37.0	45.7 **
OOIP, BBLS/Acre ft	557	735	598
Estimated primary production, MMBBLS	6.0	2.2	4.5
Estimated incremental production, MMBBLS	5.7	5.8	7.6
Total recoverable reserves, MMBBLS	11.7	8.0	12.1
Primary recovery factor, %	15.0	6.0	9.9
Incremental recovery factor, %	14.3	15.7	16.6
Total recovery factor, %	29.3	21.6	26.5

* Data from SPE 28733

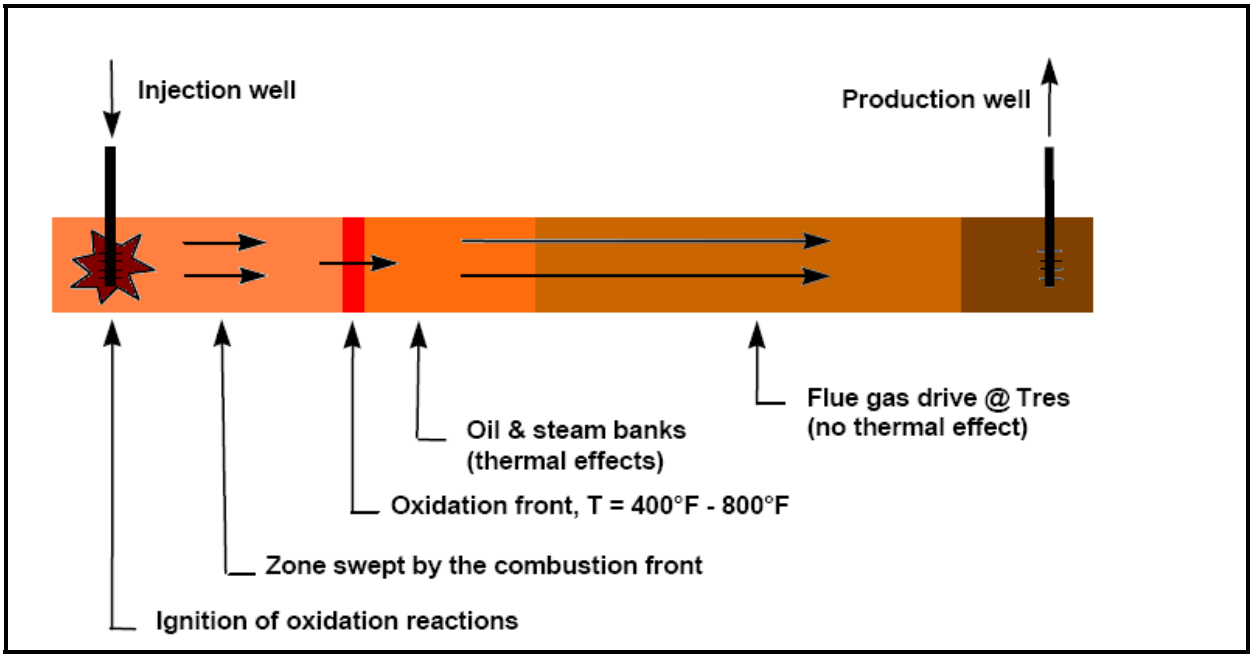

Figure 6.1: Various Reaction Zones during Air Injection in Light Oil Reservoirs (after Clara *et al.*, 1999)

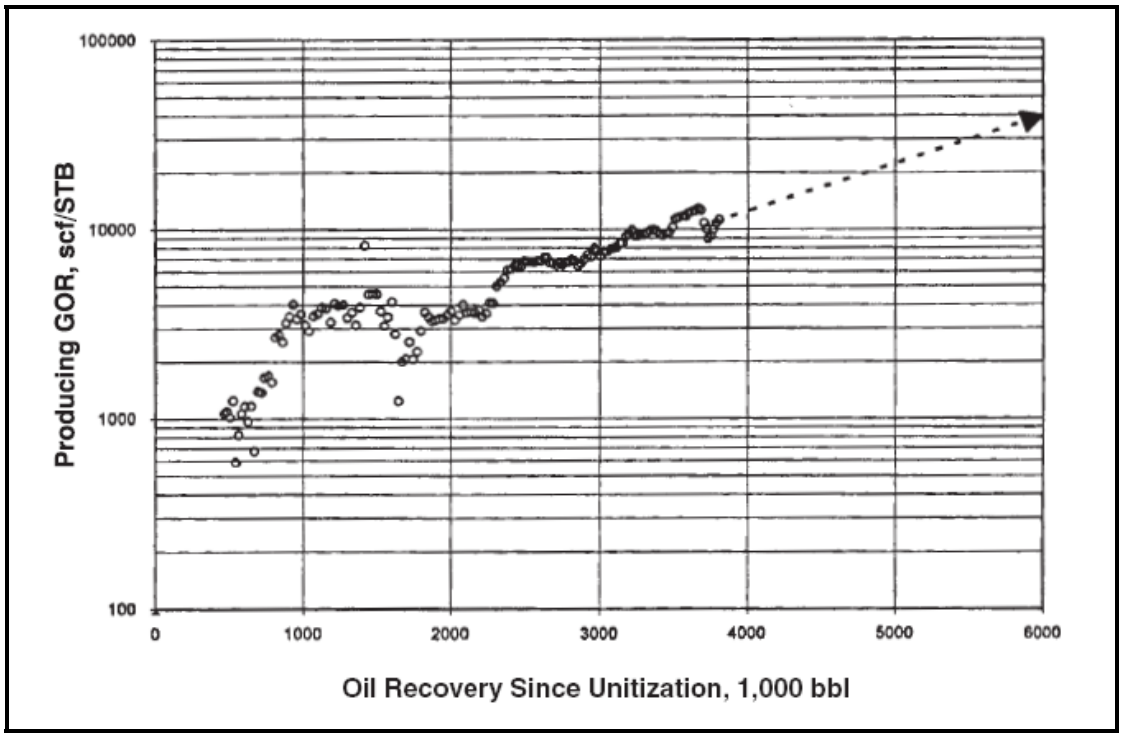

Figure 6.2A: Oil Recovery vs. Producing GOR – Buffalo Field (after Fassihi *et al.*, 1997)

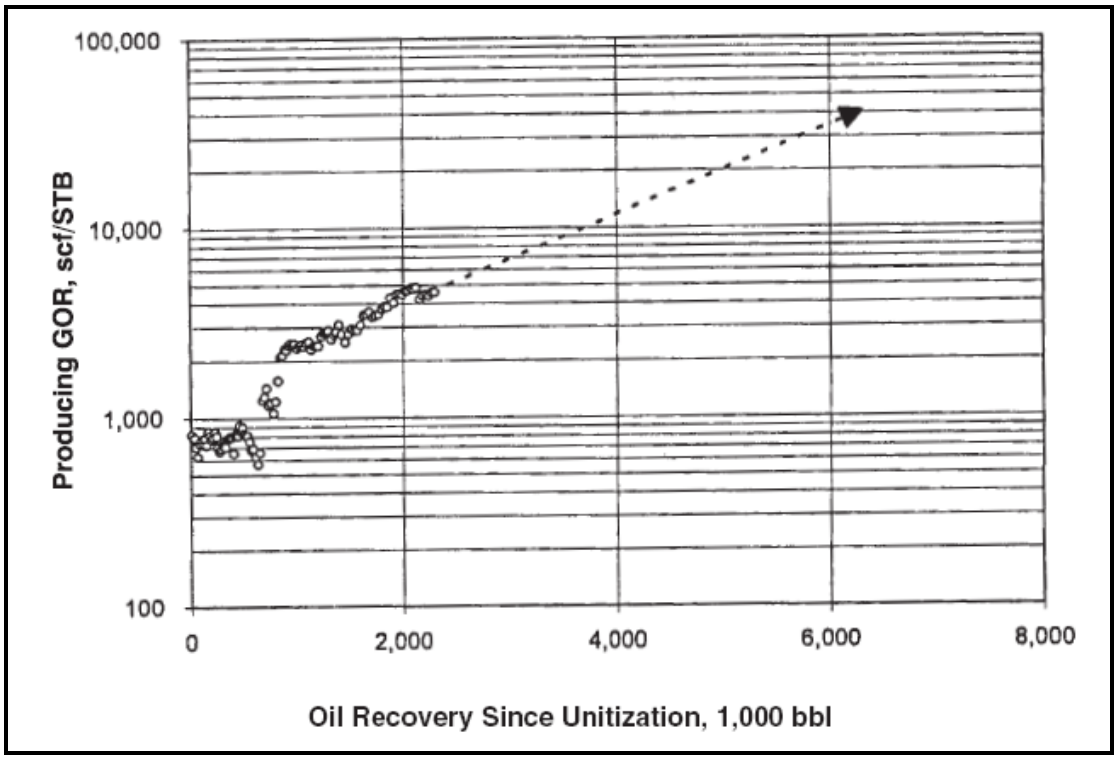

Figure 6.2B: Oil Recovery vs. Producing GOR – Medicine Pole Hills Field (after Fassihi *et al.*, 1997)

Appendix D: Cost Share Data Provided by Anadarko Petroleum

K2 Field is located in the deepwater Gulf of Mexico in blocks Green Canyon 518 and 562. Production is from the M14 and M20 reservoirs at subsea depths of approximately 25000 feet. Production commenced in May 2005 from subsea wells tied back to the remote host platform at Marco Polo field. Well and reservoir performance continuously declined from a peak rate of 40,000 STB/day indicating the lack of natural drive energy. Forecasts of oil recovery were less than 20%, and with the large oil resource of over 700 MMSTB oil there exists a large target for improved oil recovery processes.

Anadarko and its partners commenced the screening of IOR processes and determined that further work was required to evaluate water and nitrogen injection. Significant studies were performed from 2006 through 2008 particularly related to the implementation of nitrogen injection. Much of the results of this work is documented in the Offshore Technology Conference paper OTC 19624, “Design and Initial Results of EOR and Flow Assurance Laboratory Fluid Testing for K2 Field Development in the Deepwater Gulf of Mexico,” presented at the May 2008 conference in Houston, Texas.

Anadarko agreed to further the study of IOR and in particular nitrogen injection by providing the data from nitrogen evaluation studies as data in kind contribution for RPSEA 1701. Most of the data provided is in the form of fluid laboratory studies to capture the impact of nitrogen injection on the formation of asphaltenes and in the establishment of miscibility conditions with oil in-situ. Additional laboratory work is in the evaluation of impact of nitrogen on flowing conditions in the tie-back of production through wells and flowlines along the seabed (i.e. flow assurance).

Some of the key findings in this work by Anadarko and its partners are summarized below:

1. Solubility-Swelling Tests (PVT data)
    a. N2 solubility is 29.2 mol% at 8140 psi saturation pressure
    b. Asphaltene onset pressure for 10 mol% N2 increases to about 13,000 psi
    c. Any M14 reservoir oil contacted by N2 observed drop out of asphaltenes
    d. 1.135 Swelling Factor, 0.736 g/cc Density are of the liquid oil phase
    e. The equation of state (EOS) model was tuned saturation pressure, solubility, swelling, density, and viscosity PVT properties data
2. Multi-Contact Tests (Compositional data)
    a. This is the most direct lab test to understand multi-contact miscibility, vaporizing gas drive process
    b. Equilibrium gas phase compositions and PVT properties (density & viscosity TBD) at the Critical Mixture for MCM should characterize the Miscible Phase that is displacing reservoir oil.
    c. The immobile residual oil phase behind the initial mobile gas front is contacted by more initial nitrogen gas and the process continues.
    d. Precipitated asphaltenes form a 3rd solid phase
3. Slim Tube Tests (Miscibility data)

a. Slim tube total oil recovery at 8000 psi is 90%

b. Minimum miscibility pressure (MMP) is 5300 psi at 208 F (85% ST Oil RF)

c. Stock tank oil RF below MMP drops steeply

d. Since stock tank oil RF above MMP continue to increase, possible pressure effect on RF above MMP

e. All stock tank data needs to be matched for EOS to be considered completely valid

A summary of list of the laboratory and other data provided by Anadarko follows:

1. PVT Report: 1_M14_562 #3 BP2_25136 ft_Black Oil PVT 5-15-03.pdf
2. PVT Report: 2_M14_518 #2 BP1_26859 ft_Black Oil PVT 7-13-04.pdf
3. PVT Report: 3_M14_518 #2 BP1_26859 ft_EOS Cleaned 8-13-04.pdf
4. PVT Report: 3_M14_518 #2 BP1_26859 ft_EOS Cleaned 8-13-04.pdf
5. PVT Report: 5_M20C_518 #2 BP1_29007 ft_EOS Cleaned 8-19-04.pdf
6. K2 March 2007 Field Sampling Report 3-19-07.pdf
7. K2 10 STO Sampled 3-2007 Draft Report 10-4-07.pdf
8. M20 Oil Gravity-Asph Slide #19 from K2 Lab Studies 12-10-07.ppt
9. Pencor Asphaltene Onset Pressure Lab studies:
   a. GC562n3_BP02_M14_asphaltene_onset_28870-27.xls
   b. GC562n3_BP01_M20C_asphaltene_onset_28848_31.xls
   c. GC562n3_BP01_M20C_Asph_prec_28848-31.xls
   d. GC562n3_BP01_M20B_asphaltene_onset_28848-28.xls
   e. GC562n2_BP01_M20A_RI_28300-10.xls
10. SGS K2 Asphaltene Risk Assessment Report Final 2-1-05.pdf
11. AOP-HPM Draft Report Corrected for N2 Added GOR 3-3-08.pdf
12. Slim Tube Tests:
    a. Fig 10_8000 psi Slim Tube OIl RF Data 12-21-07.xls
    b. Fig 10_8000 psi Slim Tube OIl RF Data 12-21-07.xls
    c. Fig 11_5500 psi Slim Tube Oil RF Data 1-23-08.xls
    d. Fig 11_5500 psi Slim Tube Comp Data 1-23-08.xls
    e. Fig 12 Slim Tube Oil RF Data 4500 psi 2-20-08.xls
    f. Fig 12 Slim Tube Comp Data 4500 psi 2-21-08.xls
    g. Fig 13_4000 psi Slim Tube Oil RF Data 1-23-08.xls
    h. Fig 13_4000 psi Slim Tube Comp Data 1-23-08.xls
    i. FHL 2-21-08 OTC Paper - K2 ST-MMP RF vs PVINJ Plot.xls
    j. Multiple Contact Draft Report 12-6-07 FHL Edited 3-4-08.doc
13. Presentation to RPSEA Working Committee by Frank Lim of Anadarko on June 9, 2009: FHL 6-9-09 PPT Slides 25-40 of K2 Cost Share Data.pdf
14. PDF copy of paper OTC 19624