Frontier Deepwater Appraisal Production System (APS)

"*Innovative engineering step change solution for the Paleogene - because the 20K Supply Chain can't get us there.*"

SYNOPSIS

There are a significant number of very large high pressure ultra-deep water discoveries in the US Gulf of Mexico for which development planning now depends on using unproven subsea drilling and tieback systems. Final Investment Decision (FID) for many of these "elephants" cannot be justified at oil prices below $80/bbl due to several factors:

- The high cost of drilling, completion, and tieback of the subsea wells,
- The high cost of high-throughput production facilities and export infrastructure,
- The fact that it takes the better part of a year to drill, complete, and tieback each well combined with the likelihood of rapid decline curves mean that facilities have a high risk of under-performing;
- The high cost of subsea well maintenance and the complexity of the completions required for producing the complex, multi-zone reservoirs is pointing to increased likelihood that hundreds of millions of barrels will be "left behind" (i.e., never be recovered),
- The extremely long drilling times and high cost of appraisal wells as well as the apparent impracticality of short-term testing mean that corporate leaders are being asked to make huge bets and long term capital commitments with very little information or insight into reservoir or completion performance.

It is very difficult for Executive Management to make such risky bets with so little crucial information and with so much downside potential. The early result is they are selling down or out of what was once considered a highly attractive deep water play – a play that had already attracted billions of dollars invested into leases and technology development prior to the oil price collapse.

Increased accessibility to wells has been proven to enhance reserves recovery. So, because dry tree tieback facilities offer an opportunity for "hands on" surface access to wells – greatly reducing the costs and time for drilling, completing, and maintaining wells, they have been seen as the development solution of choice when there is significant concern about the need for well intervention. Supply chain and business solutions are insufficient to solve the problem which requires innovative engineering systems that reduce drilling, completion, intervention and operating costs. Unlike many previous projects, Paleogene projects are not about the facility cost. Whether it is a spar, TLP or semisubmersible is inconsequential for a successful cost effective project. It is all about well construction and well operating costs and increasing the reserve recovery per well. This is a paradigm shift that has yet to be realized by many Operators trying to deliver a commercial Paleogene development. Operators need a solution that addresses these challenges, while providing a phased entry strategy with a reusable system.

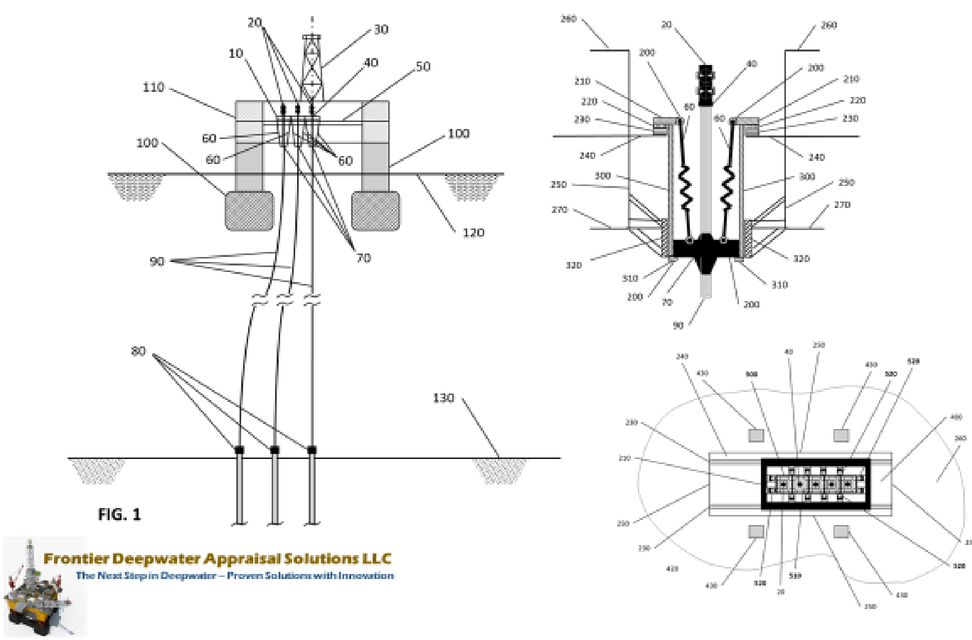
The Appraisal Production System (APS) offered by Frontier Deepwater Appraisal Solutions LLC meets this need. The APS enables a simpler adaptive development strategy which allows the Operator to commit to an appraisal program to get the dynamic production data needed to make high quality decisions on some of the biggest investment opportunities in their portfolios.

The APS concept involves -

- Taking advantage of the oversupply in the rig market to acquire a high capacity 6th generation ultra-deep water semisubmersible MODU at a very low cost;

- ➢ Converting that MODU into a drilling, completion, intervention, and production facility with a moderate but highly profitable throughput capacity (40-60 Mbopd);
- ➢ Introducing a movable wellbay structure that supports up to 5 dry tree wells with buoyancy-supported top-tensioned tieback risers (TTRs);
- ➢ Taking advantage of the great water depths to reduce HPHT reservoir pressures at the surface wellhead such that proven surface well control and production components can be used;
- ➢ Installing a fixed spread mooring system to keep the APS on station in extreme events for as long as necessary and is two orders of magnitude less likely to have a loss of position resulting in damage to equipment or release of hydrocarbons to the environment;
- ➢ Installing oil and gas export risers with pipeline tie-ins to regional infrastructure;
- ➢ Taking advantage of surface (dry tree) drilling efficiencies to greatly reduce well costs and time to completion while increasing safety;
- ➢ Taking advantage of dry tree access for efficient well maintenance operations and enhanced reserves recovery;
- ➢ Kicking off focused pre-sanction engineering and starting to drill "keepers" for production sooner;
- ➢ Reaching FID for the APS and first oil sooner enabling phased, adaptive development decisions with low financial risk;
- ➢ Gathering useful dynamic production data while operating at a profit (even in times of low oil prices);
- ➢ Stopping the wasteful years of drilling non-producing appraisal wells.
- ➢ Relocating the unit if the field/reservoir is a "bust" revealing the APS to be a "least cost" condemnation option.

APS – U.S. Provisional Patent Application Serial No. 62384626



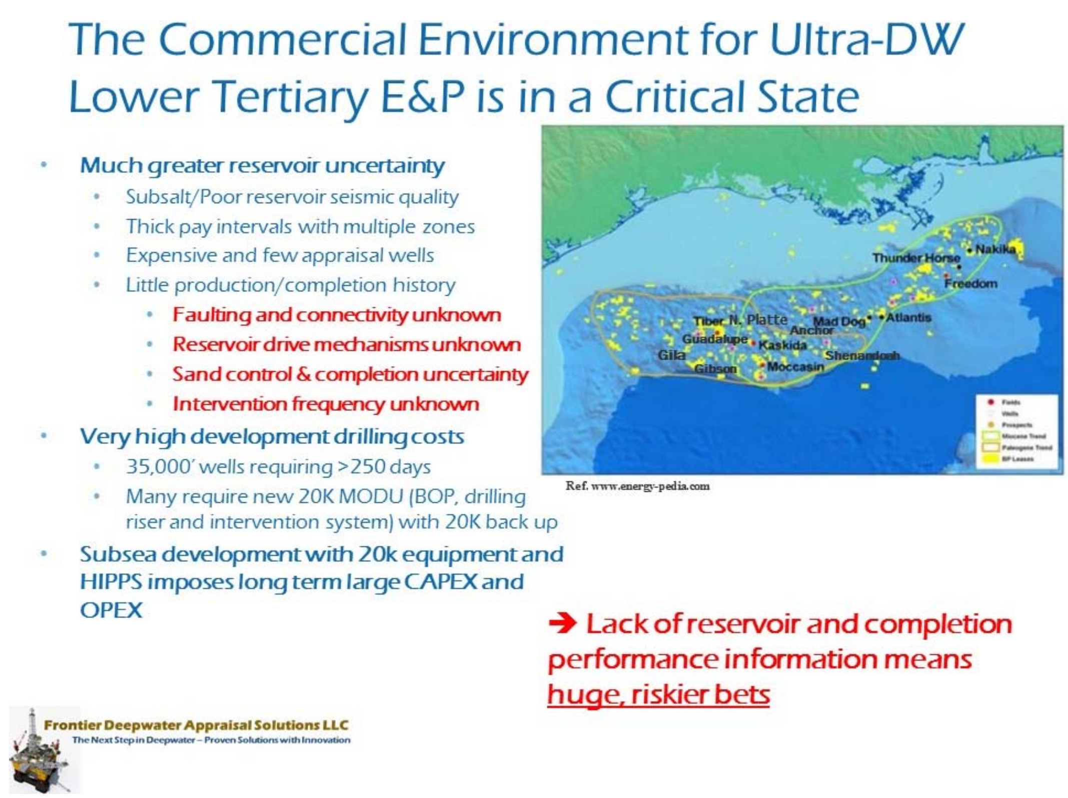
Our studies have determined that the APS provides billions of dollars of economic advantage over the 20K subsea development system approaches that are impeding development of the Lower Tertiary at today's oil prices. As a result, the APS is a "dry tree" solution that will better protect corporate assets and personnel, as well as the environment.

Paleogene Appraisal and Development Conundrum

Several recent discoveries in the Gulf of Mexico Paleogene combine extreme water depths with HPHT reservoir conditions where mudline shut in pressures can approach or even exceed 15 ksi. These wells are much deeper than what has been typical of past Miocene developments. Instead of 15,000′ to 20,000′ total measured depths (TMD), Paleogene wells may be greater than 30 000′ TMD and as much as 40,000′ when directionally drilled. In this case, where **savings between a dry versus a wet tree completion can exceed $150 million dollars per well,** drilling and completion costs become the dominant factor in the selection of the development concept. Another key advantage of dry trees is the significantly increased capability for well surveillance, wire line logging, and interventions all based on simpler completion technology. The ability to run and more easily service downhole electric pumps can significantly increase well rate and reserve recovery when compared to subsea wells. **These factors when combined highlight dry tree technology as an enabler to significantly drive down the cost of Paleogene developments**, <u>while at the same time enhancing production profiles, reserves recovery, and net revenue to substantially improve overall project economics</u>.

The GoM Deepwater Paleogene commercial environment has much greater reservoir uncertainty compared to Miocene developments. Many Paleogene reservoirs are subsalt with poor seismic resolution and the inability to clearly define reservoir extent, fault blocks, and continuity. **Exploration wells can cost over $350MM** and take more than 6 months to drill and log. The extreme costs and durations associated with drilling and evaluation mean lengthy appraisal timelines to obtain the information required to support high quality Final Investment Decisions. Most companies are not able justify a billion dollar short-term production test (e.g., Chevron at Jack/St. Malo). The result is that operators are driven to consider making much bigger and riskier financial bets on Paleogene developments with much less and incomplete reservoir information.

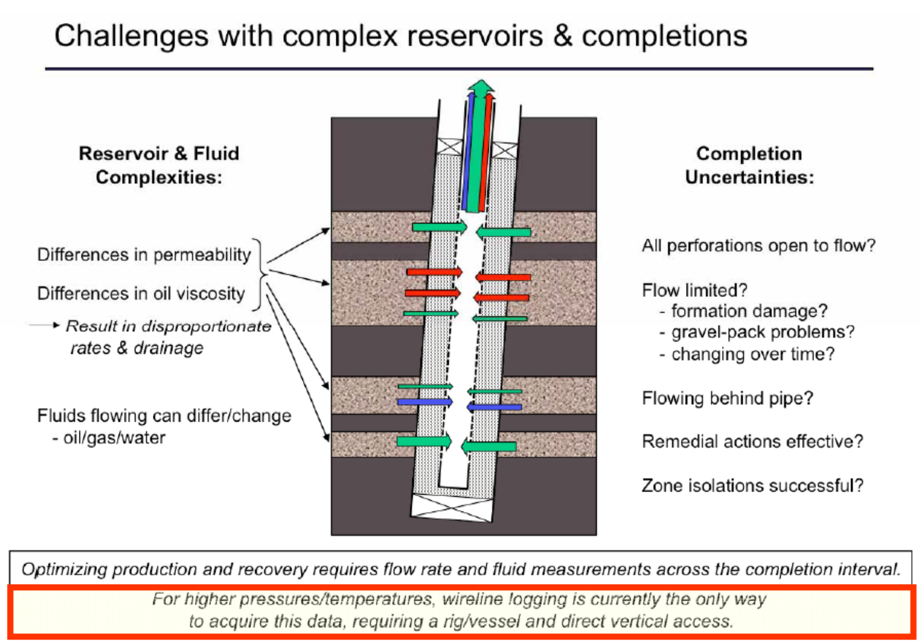
Figure 1 – GoM Paleogene Commercial Challenges



These commercial challenges have been a significant impediment to development of the Paleogene where drilling and completion costs are estimated at 60% to 75% of the total project cost. This large drilling and completion cost component is dramatic when compared to historic deepwater projects in the GoM. In early deepwater developments, the facility cost dominated project selections (e.g. the cost of a tension leg platform). Because drilling and completion costs are much larger, Paleogene development concepts are optimized by focusing on reducing drilling and completion costs, increasing reservoir surveillance, improving workovers/recompletions capability all leading to increased reserves recovery. This is **a paradigm shift** for project teams that are dominated by facility expertise and tend to remain focused on the type of floater and associated hardware to select with lesser regard for how this might impact drilling, completion, intervention, operating costs and reserve recovery. **Facility costs are only 30% to 40% of the overall Paleogene project cost so the disproportionate effort to reduce facility and topside costs rather than drilling and completion costs cannot significantly improve project economics.**

Well surveillance and interventions are extremely important in evaluating well performance and maximizing recovery from new geologic horizons. **A study performed by Statoil and the Norwegian Petroleum Directorate showed that the recovery factor from subsea wells is 15% to 20% lower than from wells with direct vertical access**. The accessibility to subsea completed wells is more difficult and represents larger costs than wells drilled from a dry tree installation. Even for minor jobs a cost prohibitive MODU mobilization is often required. **The study went on to conclude that performance from dry tree wells is 25% better than subsea wells drilled in the same geologic environment**. The main difference being that ready access for light intervention and wireline work on dry tree wells compared to the much more expensive and fewer options on the subsea analogue. Surveillance in the form of production logging, production inflow, and multi-rate production logging of individual reservoir layers has significantly contributed to better production performance of dry tree wells. Figure 2 shows some of the advantages of surveillance capabilities with dry trees (ref. SPE Paper 115365).

Figure 2 - Well surveillance capabilities with dry tree

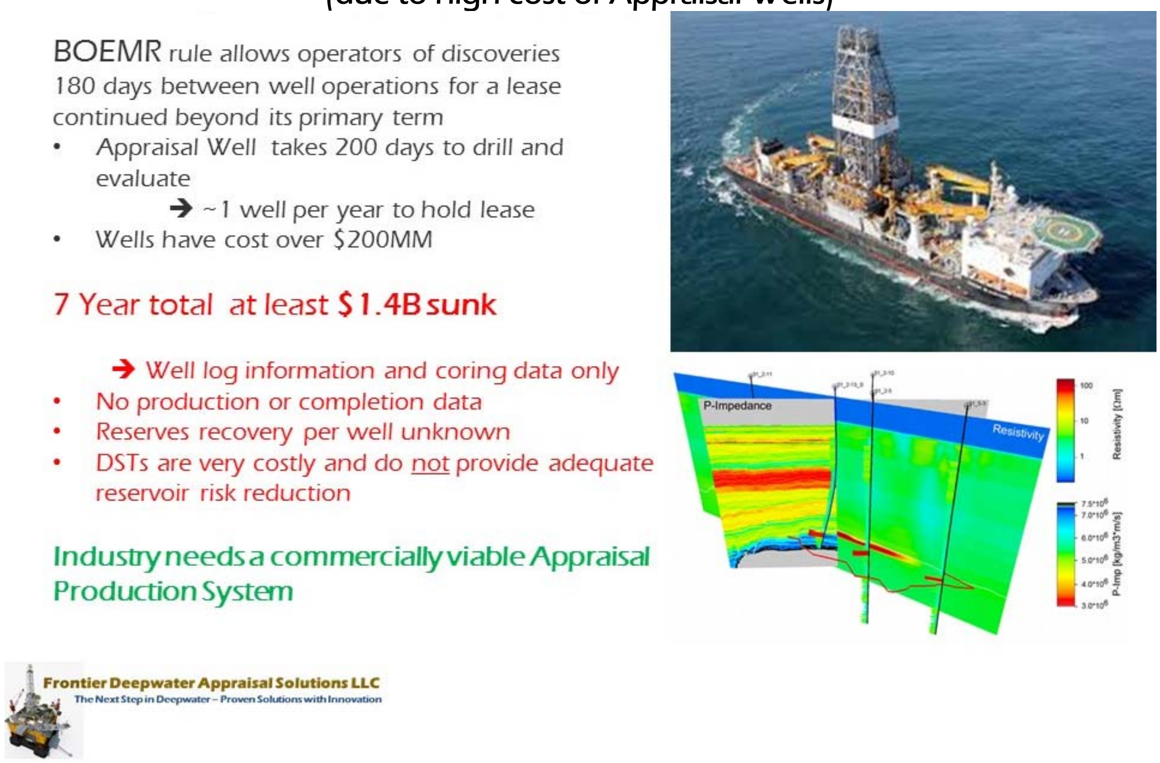


The Paleogene development key then is to focus on simpler adaptive project strategies that change the game from having to guess right to strategies that provide the operator with robust capability to appraise the reservoir, while retaining the flexibility for future redeployment and reuse, if required. This is the fundamental underlying rationale of Frontier Deepwater Appraisal

Solutions' Appraisal Production System (APS). The APS can and should be implemented much earlier in the appraisal process rather than spending billions of dollars drilling many appraisal wells which has been the industry strategy to date.

BP's Kaskida and Anadarko's Shenandoah discoveries are prime examples. Kaskida was discovered in 2006 and Shenandoah in 2009. Despite encountering significant hydrocarbon accumulations estimated in billions of barrels in place, neither discovery has yet been sanctioned. Anadarko spudded their 6th appraisal well during the 4th quarter of 2016, more than 7 years after making the initial discovery. Figure 3 highlights the key issues and hurdles Paleogene operators face.

Figure 3 – Holding onto a Paleogene Discovery is Costly
(due to high cost of Appraisal Wells)



The appraisal wells provide only well logs and core data but to answer the key questions on development strategy, Operators need dynamic production and completion performance information. In the absence of an appraisal production system, the operator's only choice is to keep drilling these very expensive wells to statically define the resource with logs and core data to the point of being able to make a relatively poor quality decision of major financial consequence. Industry needs a new strategy to address this challenge.

Compounding the cost is the BOEMR rule that allows operators of discoveries 180 days between well operations for a lease continued beyond its primary term. As mentioned in Anadarko's case, the Shenandoah appraisal period has gone on for more than 7 years at a cost of well over $1.5 billion dollars. The lease is beyond its 10 year term, hence Anadarko is "on the clock" to continue appraisal well operations until they can sanction a development or decide to relinquish the asset. With appraisal well logs and cores, they still don't have the reservoir or completion performance data to understand faulting and connectivity, reservoir drive or even fundamental issue of whether they will need sand control. These are critical uncertainties that have a profound and material impact on costs and increase the development risk profile substantially. What industry needs is an appraisal production system that provides the operator with a phased approach and the opportunity to deploy much earlier in the appraisal process so that the reservoir can be produced to provide the dynamic completion data required. Importantly, they are also generating revenue towards positive project economics while greatly decreasing their risk exposure. This is the core strategy behind Frontier's Appraisal Production System.

New Paleogene Strategy – Using an Appraisal Production System

Rather than continuing to drill many appraisal wells and being on the BOEMR 180-day treadmill, Frontier's APS (Figure 4) provides an operator with the means to move forward much more quickly with development of their Paleogene resource. It eliminates the initial need for new 20K subsea technology and the expensive commitment to a 20K MODU and workover/intervention system that can handle the high pressures.

Figure 4 – APS enables dramatic, cost effective risk reduction

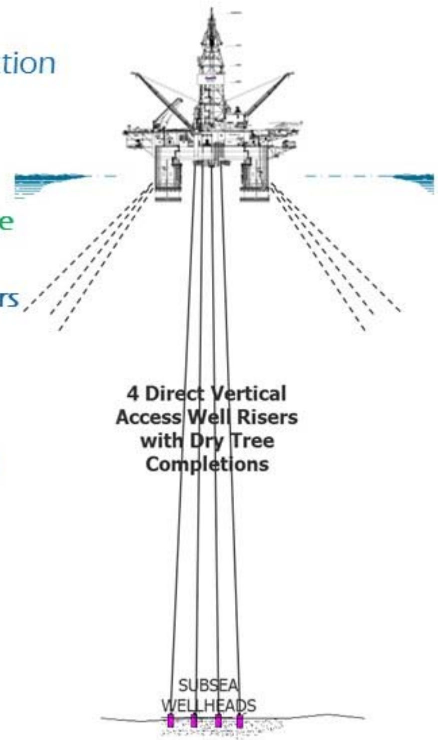
- Convert 6th Gen Semi-Submersible to Appraisal Production System (APS) with Dry Trees or Wet Trees
  - **Systems will meet ABS, BSEE and USCG requirements**
  - Direct Vertical Access for Drilling, Completion, and Well Intervention **Increases Reservoir Productivity and Reserve Recovery**
  - **Ability to use 15K surface equipment and fully rated risers eliminates the need for 20K subsea technology**
- Accelerated first oil date & earlier positive cash flow –
  - **40Mbopd production is viable at $50 per bbl**
- Gain valuable reservoir and completion data to better define the overall field development requirements

➔ **Real Risk Reduction**

- **Ability to right-size the field development scheme**

or

- **Enables "least cost to condemn" approach**



For most of the existing Paleogene discoveries, which have shut-in reservoir pressures slightly over 15K at the mudline, the dry tree shut-in pressure is below 15k at the surface allowing the Operator to use existing and much simpler technology. Frontier's APS provides accelerated first oil as well as earlier positive cash flow when compared to the 20K subsea approach and **is an economic alternative even at oil prices of $50/bbl or lower**. It delivers the valuable reservoir and completion data needed to better define the best overall field development strategy, significantly reducing both cost and risk. Just as importantly, it empowers the Operator with the lowest cost means to condemn a development with an asset that can be relatively easily redeployed to the next project. Table 1 summarizes several advantages Frontier's APS provides compared to trying to implement a 20K subsea development.

Table 1 – Six ways the APS provides real value to Ultra-Deepwater Asset Owners
• Provides Operators with the information necessary to "right size" the overall field development scheme or to positively condemn it at the lowest possible cost and risk • Lowest cost to first production • Earlier first oil due to shorter lead time to convert existing unit • Lower operating costs with dry trees, D&C systems, and production facilities on one platform • Improved production profiles and reserves recovery due to enhanced (dry tree) well access • Defers long term commitment and expense of 20K subsea systems, 20K MODUs and 20K completion/workover risers   o These big commitments to 20K systems burden the corporation even after a discovery has turned out to be non-commercial

Frontier's APS can be used with either wet or dry trees, but the dry tree configuration is particularly suited to Paleogene appraisal. Dry tree development is strongly aligned with the principles for maintaining simplicity, reliability and safety. For perspective, Table 2 summarizes a comparison of the complexities between DP MODU drilling systems and APS dry trees. Full pressure rated dual barrier top tension risers provide direct access to the reservoir and downhole equipment and is an order of magnitude simpler compared to a Paleogene wet tree completion. The use of permanent mooring systems rather than DP vessels eliminates the need for emergency disconnection of the drilling riser; the risk of loss of position due to drive-off or drift-off; and the risers do not have to be retrieved for weeks of hurricane abandonment or BOP repair. A study conducted as part of the Norwegian Deepwater Research Program (2) indicated that position excursions which are likely to lead to physical damage are around two orders of magnitude less likely on moored versus DP rigs. Dry trees can be designed to handle the full wellbore pressure and eliminate the need for complicated subsea HIPPS. Finally, a surface BOP is much simpler and more reliable than a subsea BOP. Direct hydraulic controls are used rather than the subsea electronic controls and large high pressure subsea accumulators needed to function the system. The surface BOP is readily accessible for maintenance and in many cases, can be repaired in place. This eliminates the expensive and risky task of having to pull a MODU marine riser and subsea BOP back to the surface for repair and testing – an operation that can take weeks and cost 10's of millions of dollars. Table 3 provides additional thoughts on the key risk issues between wet and dry tree developments.

Table 2 – Comparing the simplicity and security of surface (dry tree) access to subsea approach

Subsea (wet tree) Drilling Approach	Surface (Dry Tree) Drilling Solution
Dynamic Positioning ⇨ 10 year storm limitation ⇨ Hurricane and loop currents force riser retrieval o Causing weeks of down-time every year ⇨ Risk of drift or drive-off	Fixed, passive mooring ⇨ Designed for 1000 year event ⇨ Hurricane and loop currents <u>do not</u> force riser retrieval

Subsea BOP ⇨ Requires complex subsea controls and instrumentation ⇨ Must be tripped to surface for repairs ⇨ 20K system is huge and heavy	Surface BOP ⇨ All controls and instrumentation simplified by being accessible and "dry" ⇨ Can be repaired in place
Drilling Riser not rated for full pressure ⇨ Spec break at the seabed ⇨ Choke and Kill lines include hundreds of elastomer seals ⇨ Huge mud volumes in riser cannot be controlled when BOP fails ⇨ Boost line provides additional failure point	Drilling Riser rated for full pressure ⇨ Spec break at the surface BOP ⇨ Dual barrier, pressure-competent riser from wellhead at seabed to surface tree ⇨ Long Choke & Kill lines and flexible hoses avoided ⇨ Mud volumes in riser can be controlled by pumping (bullheading) directly into the surface BOP

Table 3 – Aspects of Dry Trees that Increase Safety

Wet	Dry
Emergency Disconnect System with Active Controls	No emergency disconnects required
MUX system and subsea connectors	Direct hydraulic controls
Hundreds of Elastomer Seals on Choke & Kill lines	Direct plumbing from choke manifold to surface BOP ➔ No elastomer seals
Limit for riser connection is 10yr storm	Risers remain connected in all conditions
Dynamic Positioning system has Drive Off and Drift Off failure modes	Permanent mooring system is designed to passively restrain all current, storm and hurricane conditions
Potential to yield wellhead if EDS fails	Wellheads (& risers) designed to take "1 line failure" in 100yr hurricane
Drilling Riser not rated for full pressure with single barrier from BOP to rig floor	Drilling Riser rated for full pressure with dual barriers from wellhead to surface BOP
Drilling Riser must be pulled for Hurricane Abandonment	Drilling Riser remains connected during Hurricane abandonment
Choke and Kill line droop hoses exposed to fatigue in the splash zone	Choke and Kill coiled tubing connections remain above splash zone
Riser parting results in riser being dropped on subsea infrastructure	Parting of the outer riser in a Dual Barrier system does not result in riser falling to seabed

Case Study Between 20K Subsea and APS Development of the Paleogene

To more clearly illustrate the commercial case for the APS, Frontier Deepwater commissioned Decision Frameworks LP to perform a Value of Information (VOI) case study. The study compared development economics of GOM Paleogene discoveries with large well recovery uncertainty for two different concepts: the new APS (Appraisal and Production System) facility and a standard deepwater facility (SPAR or semi-submersible) with 20K subsea wells. Both concepts were evaluated on the impact of different numbers of development wells, at $50/bbl and $75/bbl flat oil price, without inflation or oil price escalation.

The analysis suggests that the APS technology is the more valuable development concept in all scenarios, because of numerous cost savings and schedule improvements. Four main aspects drive APS value benefits:

- Lower infrastructure capex (less expensive to design and build; capable of installing dry trees)
- Lower rig rates and operating costs
- Earlier first oil, due to shorter facility lead time
- Reduced opex (lower cost of workovers, as mob/demob of a 20K MODU is not needed)

The study focused on a project schedule comparison between the two concepts where in each case an initial discovery well and 2nd appraisal well is drilled. In the case of the 20K subsea approach, FEED and 20K engineering begins with the 3rd appraisal well and carried through the 4th and 5th appraisal wells, which are drilled as keepers. Sanction and detailed engineering/procurement start after the 5th well results have been analyzed, resulting in the facility and equipment being delivered some 40 months later. The facility is installed and commissioned with first oil for the 20K wells about one year later (subsea wells completed offline from facility delivery).

The APS scenario is identical through the first 5 wells, with the last two also being keepers to be completed for first oil after the installation of the APS commissioning of the onboard rig. The difference, however is the FEED and the detailed engineering and procurement cycle. The APS uses existing 15K surface drilling and tieback technology with conversion of an existing 6th generation MODU. As with the 20K case, FEED starts at the beginning of the 3rd exploration well, but is completed after 18 months at which time the project is sanctioned so detailed engineering and procurement can begin. The converted facility is delivered some 30 months later. The APS is installed and commissioned with first oil produced about 15 months later.

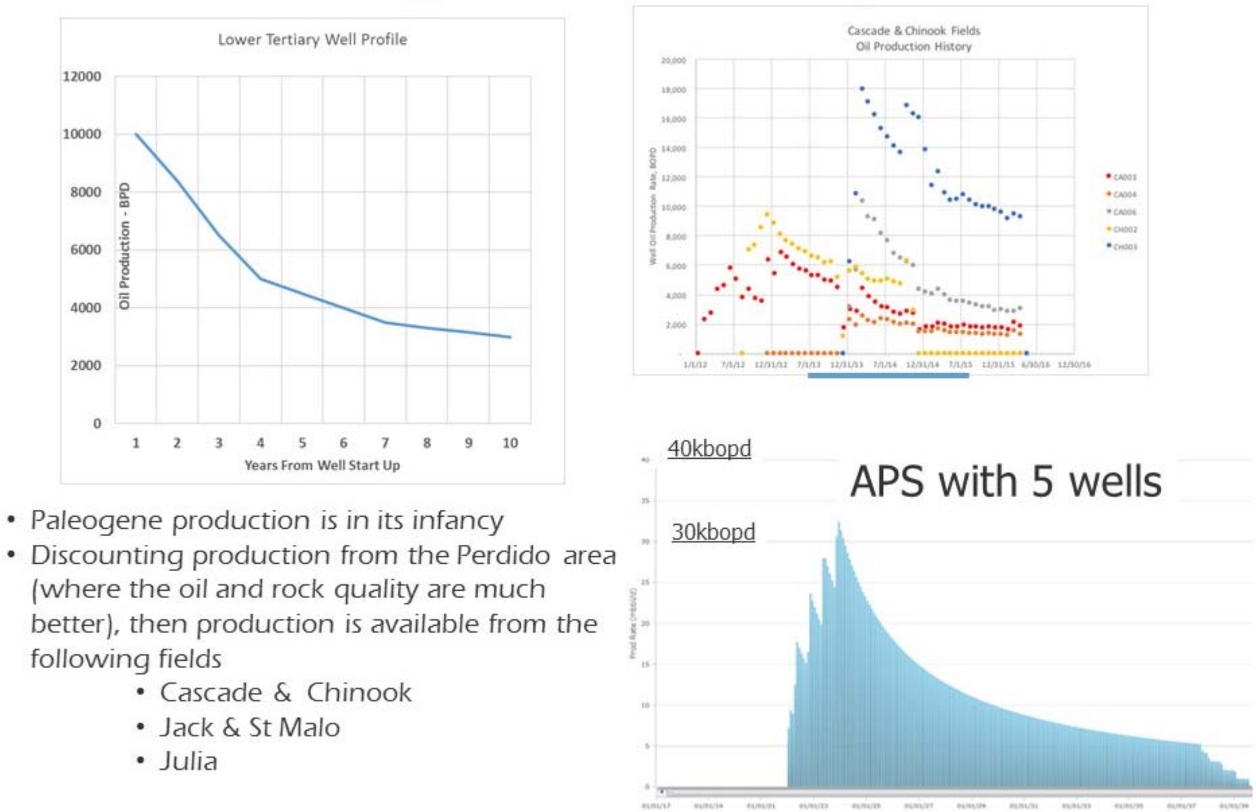
In concert with the VOI study, Frontier also commissioned a Paleogene production history study to develop well rate profiles as input to the economic comparison. Detailed analysis of well production histories was obtained from the US BOEMR website for:

- Cascade
- Chinook
- Jack
- St Malo and
- Julia

The most recent wells were analyzed using decline analysis. Figure 5 shows the key results that were used as input to the VOI analysis. In general, the declines were best fit by hyberbolic decline. Three different well profiles were developed spanning a low to high initial rate of 5,000 bbls/day to 15,000 bbls/day. Some of the caveats noted from the analysis included:

- The long term behavior of Paleogene is still undetermined with the more modern and highly stimulated wells having less than two years of declining production history.
- The wells exhibit a steep decline, however only in recent production history do we see the leveling off of the decline and a more hyperbolic shape.
- The ultimate leveling off of the production will determine the productivity of these wells and that won't be established for several more years.

Figure 5 – Paleogene Production Data and Decline Curve Model



2016 Decision Frameworks, L.P. Evaluation for Frontier Deepwater Appraisal Solutions

Figure 6 shows the VOI results comparing the 20K subsea to the APS through 5 wells at $50/bbl flat oil price going forward. Starting the FEED at the beginning of the 3rd appraisal well (as with the new build semi and 20K approach), **results in accelerated first oil at substantially reduced total CAPEX**. The significantly higher CAPEX for 20K subsea development drilling and tiebacks continues to drive the cumulative cash flow more and more negative. In contrast, the cumulative cash flow for the APS has already climbed into the positive as all 5 wells continue to produce.

Figure 7 shows a longer duration comparison at $75/bbl in which the APS has generated nearly +$2 billion dollars, while the 20K subsea semi remains nearly -$2 billion dollars negative. For both scenarios, the wells were drilled, completed and produced through time with no intervention and or remedial activities. The following list notes aspects that would further enhance the APS economic performance but were not modeled in the economics:

- Well recovery should be higher in dry tree wells, when compared to subsea.
- The rig and intervention/surveillance availability should be much greater for the APS rig compared to the 20K MODU.

- Downhole pumping ("lift") of dry tree wells was not included, however many of the wet tree wells reflected in the Paleogene reservoir study are being produced with subsea pumping.
- The APS can provide option value to learn about the discovery and then finalize the full field concept phased solution. This "optimization" value is not modelled in this analysis but can be done to reflect the significant value in optimizing full field development cost and schedule.
- The value of "least cost to condemn" case is not included where the APS may be more quickly and cheaply moved and reused on another project.

Figure 6 – 5 Well Development Comparison at $50/bbl

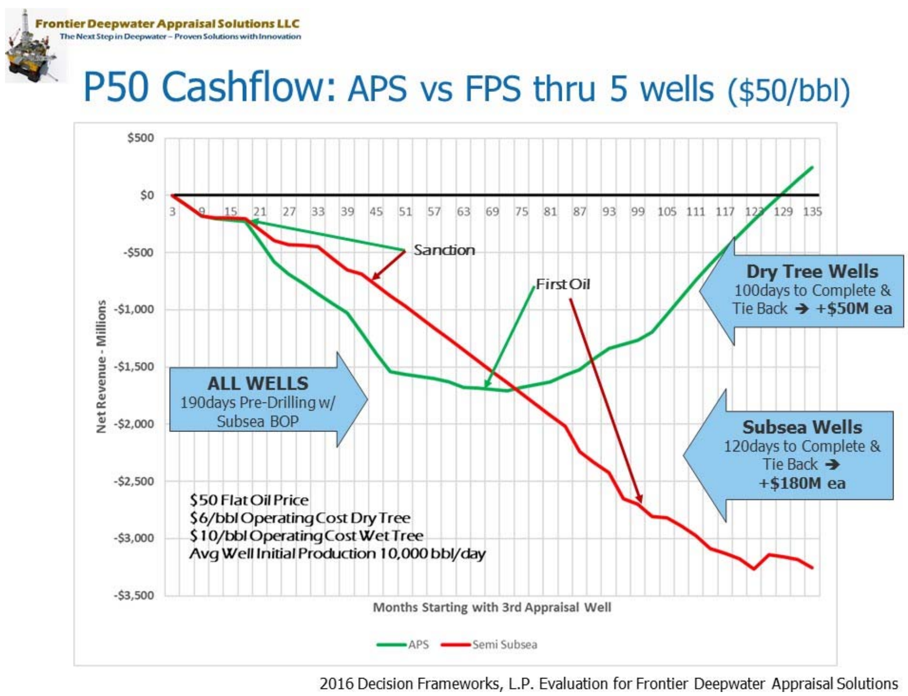
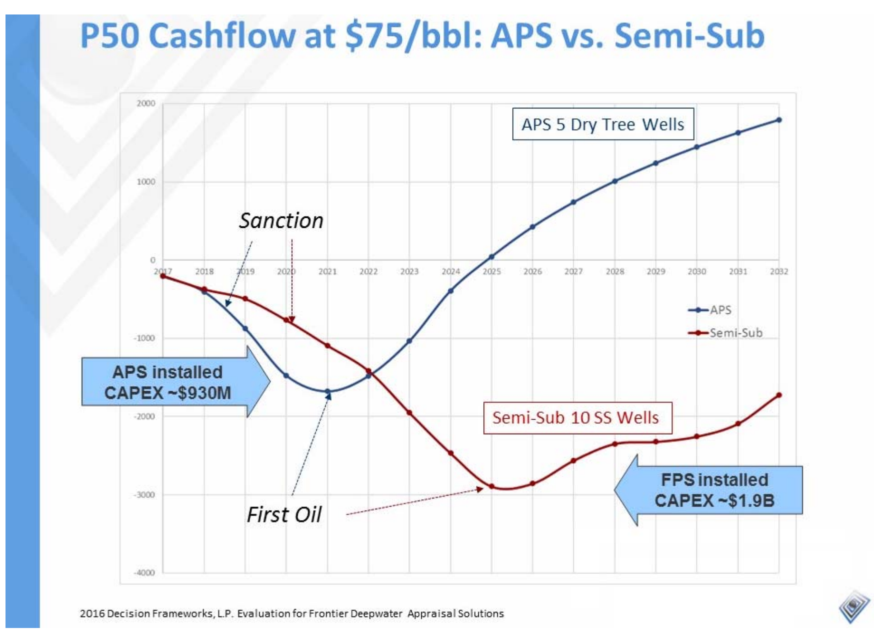


Figure 7 – 5 Well Development Comparison at $75/bbl



These evaluations were run by Decisions Frameworks LP in the 3esi Enersight integrated asset development software. The probabilistic analysis, work flow and graphics were run using Decision Frameworks DTrio and TreeTop software in combination with Enersight. The CAPEX, OPEX and well cost data was developed using 2014 – 2015 project cost estimates minus 20%.

The Decision Frameworks team extended probabilistic Net Present Value assessments (Figure 8) into a basic Value of Information exercise which dramatically clarifies the improvement in decision quality that adoption of the APS can bring to a Paleogene opportunity. Bringing more than one APS unit into the picture (possibly for multiple reservoirs) greatly extends the advantages of implementing an adaptive development strategy in ways that are worth exploring (Figure 9).

Figure 8 – 5 well APS outperforming 10 well subsea development at $75/bbl

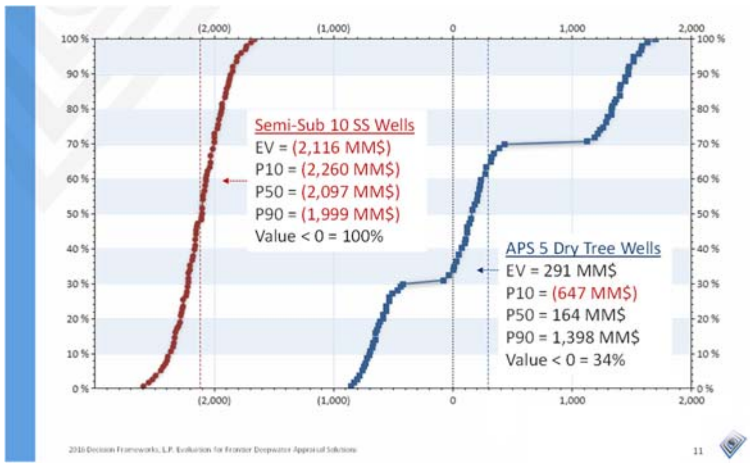
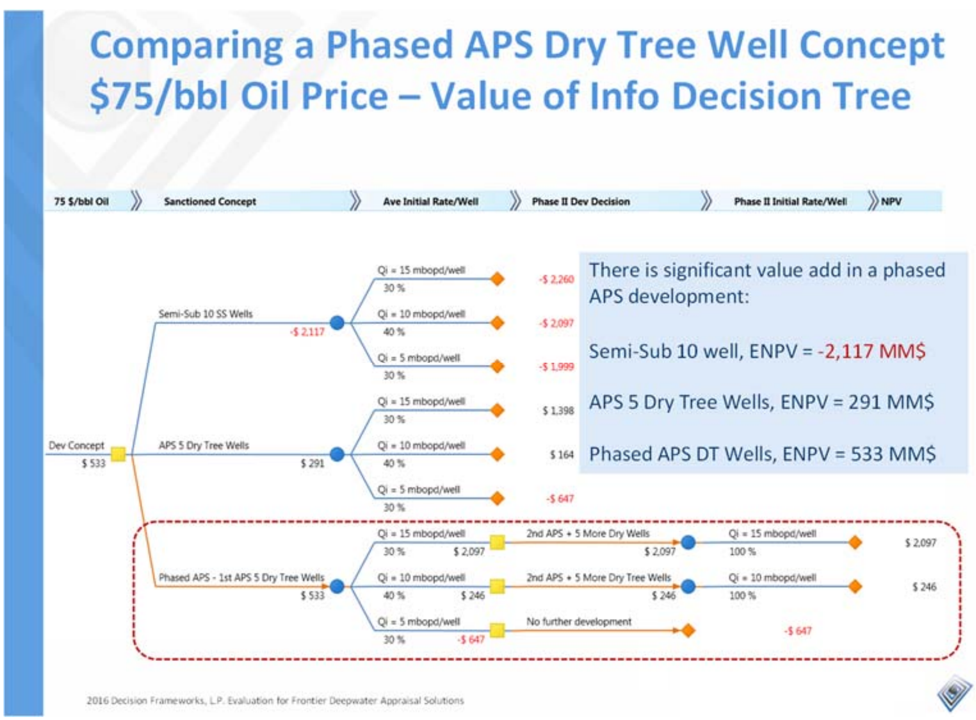


Figure 9 – Two 5-well APS unit enhance the VOI advantage



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