Innovation,

Heerema Marine Contractors' Thialf heavy-lift vessel is shown here in March on location at Shell's Perdido Hub Development, installing the 9,500-ton topsides and living quarters atop the spar. The topsides were hoisted onto the spar in a single lift of the Thialf.

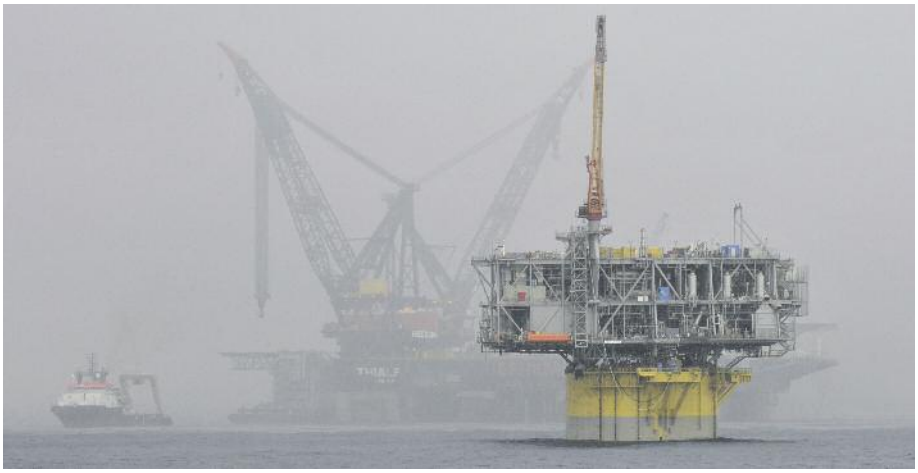
Engineering Driving Development Projects In Deep- And Ultradeepwater Gulf

By Tim Beims

HOUSTON–Some of mankind's most dazzling engineering achievements are not towering over a downtown city skyline or probing the distant reaches of outer space, but sit hundreds of miles off the U.S. coastline in the open ocean of the Gulf of Mexico.

In the deep- and ultradeep waters of the Gulf of Mexico, oil and gas companies are installing surface structures the size of high-rise buildings, engineered to facilitate some of the most complex mechanical operations ever conceived in an environment so inhospitable that it ranks as one of the few places on the planet almost entirely devoid of even elemental forms of life. Far beneath the waves, withstanding the crushing weight of thousands of feet of water, mazes of steel and umbilical extend for miles across the seafloor, putting a curiously human architectural footprint in a cold, dark "other-worldly" landscape no person has ever set foot on.

STORY NUMBER: 4-6M/H-Sp/P6-C6
STORY SLUG: Gulf/Deepwater Developments
AUTHOR: TB



Shell's Perdido Hub Development in the Perdido Foldbelt is establishing first production from the Lower Tertiary play using a direct vertical access spar stationed in nearly 8,000 feet of water to produce wells in up to 9,627 feet of water. The spar was installed late last summer and the topsides were mated to the spar in mid-March using a single lift of Heerema Marine Contractors' *Thialf* heavy-lift vessel. Shown here, from top to bottom, is the *Thialf* arriving on location, installation of the living quarters/helipad, and the spar with all topsides facilities in place. Initial production is planned for early 2010. *Photos courtesy of Shell and Jan Berghuis Terschelling, captain of Heerema's Retriever.*

These "cities at sea" are built on equal parts technology, ingenuity and opportunity, the result of the never-ending quest to find and develop new reserves in geology never before touched by a drill bit. Deepwater developments are among the most technologically sophisticated and expensive projects the industry has ever undertaken, but even with depressed commodity prices and distress in the global financial markets, Gulf operators are continuing to bring their oil and gas discoveries on line in 2009.

One of the most heralded projects is progressing full speed ahead in the Gulf's most distant and infrastructure-challenged region: Shell Offshore Inc.'s three-field regional development in the Perdido Foldbelt in the ultradeepwater Western Gulf frontier some 200 miles off the Texas shore. Not only is the Perdido Hub chalking up numerous technical "firsts," but it also is establishing first production from the Lower Tertiary (Paleogene) play, according to Bill Townsley, Shell's venture manager for the Perdido Hub Development.

"The Perdido Development is an example of how committed Shell is to keep pushing the boundaries in the Gulf into deeper and deeper water," Townsley says. "We have been in the deepwater Gulf from Cognac in 1979, when we broke the 1,000-foot water depth barrier at Mississippi Canyon 194, to where we are now mooring a spar that will be almost as tall as the Eiffel Tower when fully operational in nearly 8,000 feet of water, to produce subsea wells in up to 9,627 feet of water. This is a world-class project in every respect."

The Perdido development concept features a direct vertical access (DVA) spar with full drilling functionality as a common hub to gather, process and export production from subsea wells located within a 30-mile radius of the facility, Townsley Says. Stationed at Alaminos Canyon 857, the 555 foot-long, 50,000-ton spar services wells in the Great White (the largest field), the Tobago and Silvertip fields eight miles to the west. Shell operates the Perdido project, including all three fields, on behalf of partners BP and Chevron.

Townsley reports that the spar was installed late last summer, anchored to the seafloor by nine polyester mooring lines more than two miles in length. It was constructed by Technip Offshore in Pori,

Finland. The tri-level drilling and production topsides, designed by Alliance Engineering and constructed by Kiewit Offshore, were floated to location and mated to the spar in mid-March using one lift by one of the world's largest offshore cranes.

"Controlling the weight of the spar and topsides has been a focus of the facility design work, because reducing weight means reducing cost," he remarks. "One of the parameters in keeping costs down was to make the topsides light enough to be hoisted onto the spar with a single lift. That is huge from the standpoints of safety, cost and project scheduling."

Ambitious Plan

Initial production is planned for early 2010, with the facility capable of handling 130,000 barrels of oil equivalent a day. The development plan calls for up to 35 subsea wells, 22 of which will have direct vertical access wet trees, connected to seafloor separation and electric submersible pump systems to separate the oil and gas and boost the liquid product stream before sending it topside, Townsley details.

Perdido is a big and ambitious development, even by Shell's standards, Townsley goes on. "This is a major project–our largest-scope development to date in the Gulf of Mexico–with a large number of wells produced through one of the most sophisticated production systems we have ever engineered," he relates. "With the Perdido Hub, we are opening the Lower Tertiary play in ultradeep water in a remote, isolated part of the Gulf. That is no small task, and we have had to overcome a number of challenges to get it done."

One challenge that immediately comes to mind is water depth, Townsley holds. "The Perdido Hub is the deepest spar in the world at 7,817 feet of water, as well as the deepest drilling and production facility. Perdido already has set a world water depth record for drilling and completing a subsea well in 9,356 feet of water, and we will break that record when we drill another subsea well in 9,627 feet of water at the Tobago Field," he reports.

"On top of that, in March we completed the deepest pipeline cut and connection in 4,500 feet of water to tie in production from the hub," Townsley adds, noting that the facility's two export lines run 77 (oil) and 107 (gas) miles north before tying into pipelines.

Both the unique geology of the Perdido Foldbelt and the technological solutions Shell has come up with to jointly develop the fields also set Perdido apart, Townsley contends. "The seafloor terrain is very rugged, and the subsurface geologic setting is different from anything that has previously been produced in the Gulf," he states. "Using a DVA spar with wet trees and full host-scale subsea separation and boosting are also novel concepts."

Put all the pieces together, and the Perdido Hub becomes the new standard-bearer for what can be accomplished with enough cutting-edge technology and engineering expertise, Townsley suggests. "This record-breaking development is pushing the boundaries on everything from the surface facility to the subsurface equipment to open a new play and deliver the Gulf's first Paleogene production to market," he remarks. "There are a number of innovations built into the development design that advance the state of deepwater technology."

Unparalleled Geology

According to Townsley, one of the biggest issues Shell's subsurface engineers faced in terms of managing drilling risk and invariably getting the Perdido project sanctioned was simply obtaining an adequate understanding of key reservoir attributes in a geologic environment that literally had no parallels in the Gulf of Mexico.

"The key thing was getting our hands around a reservoir with no Gulf analogies. Paleogene-aged reservoirs are older and deeper, and tend to have more challenging porosity and permeability characteristics than younger reservoirs. In addition, unlike the rest of the Gulf, this is a hydropressured reservoir instead of a geopressured reservoir," he elaborates. "One of the benefits is that drilling is a bit more straightforward than with a geopressured reservoir, but the flip side is that you have less reservoir energy to help lift the oil to surface."

In contrast to other reported Lower Tertiary discoveries, none of the three fields in the Perdido Hub Development are located beneath the Gulf's salt canopy, but Townsley points out that the reservoir does appear to be highly complex.

"Although subsalt is not an issue at Great White, Tobago and Silvertip, appraisal drilling indicates we have a very complicated reservoir setting with faulting," he reveals. "We are fortunate in that 3-D seismic imaging works very well in this area. We have used the latest seismic techniques–including tilted transverse isotropy (TTI) 3-D prestack depth migration–to evaluate the reservoir, but we recognize that compartmentalization is one of the risks that is still in front of us. The only way to really understand compartmentalization is to move to full-field production."

Well test results also indicated variability in the crude oils trapped within the Lower Tertiary zones, Townsley states, adding that well depths in the three fields range from 3,000 to 8,000 feet below the mud line.

"We are finding a mixed blend, depending on the reservoir, ranging from a very high-quality crude at the Great White Field to a heavier crude in some of the shallower reservoirs," he says. "What we know for sure is that the reservoir is faulted and hydropressured, but it is still unclear exactly how much drive we will get and whether it will be anything more than depletion drive."

Subsea Smarts

Because of the hydropressured reservoir, one of the most critical technological components in the entire field development design is the subsea separation/boosting artificial lift system, according to Townsley. "Separating the oil and gas at the seafloor and then pumping it to the surface is one of the cornerstones that enables us to enhance recovery so the hydropressured reserves can be produced at commercial rates," he comments. "At Perdido, the real smarts are on the seafloor."

Perdido is the first full host-scale application of subsea separation and boosting, and at the same time takes the technology into unprecedented water depths, Townsley notes. "We knew we would need 20-plus well slots to fully develop the reservoir, but there was no way the facility could be sized to host that many slots. So we have come up with a way to route commingled production from the wells to a manifold, which then redistributes the multiphase production into five 'cyclonic' production caissons, where the oil and gas are separated into two streams and boosted to surface. In so doing, we have only five conduits

coming from the seafloor to the spar."

The "magic" happens in each of the five caissons, where a cyclonic spin is applied to the multiphase oil and gas flow as it enters, causing the gas to separate and go up the annulus of the caisson and the liquids to fall to the bottom, where 1,500-horsepower ESPs lift it to surface. "By separating the oil and gas, and using submersible pumps at the bottom to boost the liquids, we are effectively removing 8,000 feet of head (±2,000 psi of back pressure) from the well bores, which enables these hydropressured wells to flow at good rates."

The DVA spar is designed as much to provide an efficient solution for drilling as it is to produce the wells, Townsley contends. "With all the complexity, faulting and potential compartmentalization, we know we are going to have to drill for many years to intersect all the reserves," he says. "Using wet trees with a DVA spar is a creative way of drilling and completing subsea wells. Most of the Great White Field can be accessed by simply moving the spar over one of 22 well surface locations underneath the spar to have direct vertical access to the well bore."

Once positioned directly above a subsea well, the wet tree DVA system uses a single, high-pressure drilling and completion riser suspended from the spar to enter the well bore while a blowout preventer on the surface maintains well control during drilling, completion and sidetracking operations. Townsley says this configuration allows a large number of subsea completions to be accessed by the spar's rig, resulting in significant time and cost savings throughout the drilling and completions program.

Enhanced Safety Systems

The spar's multilevel topsides incorporate numerous enhanced safety systems. Given Perdido's remote location and the fact that it is so isolated from existing infrastructure, Townsley says Shell has to account for a number of logistical and safety concerns. "Unlike the Central Gulf, there is very little infrastructure near the spar," he states. "As many as 150 people may be on the Perdido facility at any one time, and with Houston some 200 miles away, we have had to develop plans to take care of any problem we might encounter on the spar on site to protect our people and assets."

With onboard hydrocarbon storage (Perdido is the first Gulf spar to store hydrocarbons in its hull), the isolated location, and dense equipment spacing on the compact topsides, Townsley reports that Shell has engineered robust fire suppression systems into the facility to deal with any potential incident before it can escalate, including:

- Blast-resistant living quarters;
- A blast-proof fire wall that spans the production and cellar decks;
- State-of-the-art fire detection and active protection systems;
- A level gas detection and integrated emergency shutdown system;
- A rapid blowdown system that enables all process equipment to be quickly depressurized; and
- A high-capacity water treatment system.

"Perdido also has the largest fast rescue craft in the Gulf (accommodating 27 passengers) and an oversized helipad with two of our largest dedicated helicopters (long-range Sikorsky S92s capable of seating 24 passengers and crew)," Townsley says. "While it was important to make the facility compact and lightweight, we are so far from shore that it also was critical to design state-of-the-art health, safety and environmental considerations into every aspect of the facility."

Flow assurance is another area where the Perdido design leaves nothing to chance. In addition to a dedicated chemical flow assurance system, should the facility have to be temporarily shut in for a storm evacuation, Townsley says the array of flowlines on the seafloor includes a loop to allow a successful startup when production is resumed.

When topsides installation is complete, Townsley says the platform drilling rig will be constructed and Shell will begin the process of commissioning the facility and preparing the wells for first production. At the same time, one mobile rig will continue to drill wells at the Great White, Silvertip and Tobago fields while work continues over the next several months to commence spar operations.

"We will have our hands full for the foreseeable future getting all the wells in the three fields drilled, completed and placed on line, but other discoveries have been made in the Perdido Foldbelt area," Townsley concludes. "The ability to tie a discovery back to an existing facility when capacity becomes available lowers the threshold of what can be commercially developed. Looking long term, there is no doubt that the Perdido Development is a critical piece of infrastructure for the entire western part of the Gulf."

Production is scheduled to commence at the Cascade and Chinook Lower Tertiary fields in mid-2010 using the Gulf's first floating production, storage and offloading system. When commissioned in more than 8,500 feet of water at Walker Ridge 249, the *BW Pioneer* will establish a world water depth record for an FPSO installation. The FPSO is shown here undergoing refurbishment and conversion work in Singapore.

Cascade And Chinook

On the heels of the Perdido Hub's start-up, Devon Energy Corp. and its partners–

including operator Petrobras–expect to commence production of the Cascade and Chinook Lower Tertiary fields in mid-2010, using the Gulf's first floating production, storage and offloading system, says Tony Vaughn, senior vice president of Devon's Gulf division.

The FPSO, the *BW Pioneer*, is undergoing refurbishment and conversion at a shipyard in Singapore. Vaughn reported in early March that work was about halfway complete, with the FPSO scheduled to arrive on location at Walker Ridge Block 249 in the first quarter of 2010. Devon owns a 50 percent interest in Cascade, with operator Petrobras holding the other 50 percent as well as a 66.67 percent interest in Chinook (Total E&P owns the other 33.33 percent).

"The development concept at Cascade/Chinook uses the FPSO as an early production system to minimize risk and capital until we better understand the producing characteristics and the performance of these Lower Tertiary wells, without committing to full-scale infrastructure development," he explains. "After 12-18 months on stream with the early production system, we should have a detailed understanding of how to optimize full-field development and be able to move to a final design concept at that point."

What might a final design concept look like? It very well may be ship-shaped, according to Vaughn, who says an FPSO could become a permanent fixture at the Cascade/Chinook regional development.

"It all depends on reservoir performance during this first phase of production," Vaughn stresses. "The final design concept could be upgrading the *BW Pioneer's* topsides to expand its throughput capacity, or maybe even bringing in a larger FPSO. Petrobras is the largest operator of FPSOs in the world and has considerable expertise in FPSO technology. Devon has experience operating FPSOs internationally and is also very comfortable using the technology."

The *BW Pioneer* is being deployed as an early production system at Cascade/Chinook. After 12-18 months on production, operator Petrobras and its partners Devon Energy Corp. (Cascade) and Total E&P (Chinook) expect to select a final design concept for optimal full-scale field development.

FPSO Advantages

One such reason is the fact that the *BW Pioneer* is designed to quickly unlatch and move off location to avoid approaching storms. Vaughn says a disconnectable turret buoy allows the vessel rotate 360 degrees, and is connected to free-standing hybrid risers that transport production from subsea flowlines to the FPSO (as well as natural gas from the FPSO to a dedicated export pipeline). The disconnect feature allows the *BW Pioneer* to release from the buoy and move to safe waters quickly during severe weather. "With the hurricane damage we have seen in the Gulf in recent years, that sort of mobility is obviously a major plus," he states.

The versatility of an FPSO also allows it to service multiple assets, Vaughn continues. "If, for example, the Cascade/Chinook wells perform at the high levels we think they should, we could deploy another facility–be it a larger FPSO or some type of floating platform–and move the *BW Pioneer* to another Lower Tertiary field, where it could again be deployed as an early production system to get oil on line while we analyze reservoir performance," he muses.

And because the produced oil is shuttled to shore by two dedicated tankers rather than shipped through a pipeline, Vaughn says an FPSO-based development also gives field operators the flexibility to deliver to different markets, effectively allowing them to maximize value by selling to the highest bidder.

The *BW Pioneer* initially will accept oil and gas production from two subsea wells in Cascade and one subsea well in Chinook, which is located 20 miles south of Cascade. All three wells produce from 27,000-28,000 feet measured depth. Subsea electric submersible pumps will boost production from the seafloor to the FPSO, and all processing requirements will be performed onboard, according to Vaughn.

When the FPSO is commissioned next year in more than 8,500 feet of water, it will establish a world record water depth for an FPSO installation. More importantly, Vaughn says it also will give Devon and its partners insights into the reservoir characteristics and production profile of the main drilling target at Cascade and Chinook: the Tertiary-aged Wilcox formation, the first Wilcox production in the ultradeepwater Gulf.

"Everything we have seen indicates the crude from our Lower Tertiary discoveries is a little heavier and a little more viscous than what we have seen in the Miocene play. It is a bit of a different animal," Vaughn reveals. "However, while it is not the typical 40-degree API gravity crude produced from the Miocene with a lot of associated gas, we do not think there are any fluid quality issues that will impact the commerciality of the project."

Crude Composition

As a partner in the Jack/St. Malo (operated by Chevron) and Kaskida (operated by BP) Lower Tertiary discoveries, Vaughn says Devon has participated in the extended well test at Jack as well as modular dynamics testing (MDT) of Wilcox formations in virtually all the wells drilled to

date. "The high volumes of the Jack well test gave us a pretty good feel for the reservoir deliverability and composition of the crude, and enabled us to calibrate the volumes and composition of the crude to fluid samples obtained from MDT in other discovery and appraisal wells," he explains.

"There is some variability in the composition of the crude as you move across the Lower Tertiary trend," Vaughn goes on. "For instance, the Cascade crude is a little different than the Jack crude. But that is to be expected, and we factor those compositional changes into our petrophysical modeling."

According to Vaughn, Devon's modeling work at Cascade indicates very little solution gas dissolved in the oil, although it does contain varying degrees of sulfur and asphaltenes. "We are factoring the sulfur and asphaltenes into our models on Cascade to make sure we understand how to deal with them during production operations," he remarks.

Depending on initial reservoir performance and the final field development concept, Vaughn says Devon and its partners expect to drill several more wells in the eight-block Cascade/Chinook area. "Future drilling will be dictated by how the first three wells perform, and what type of final design concept is ultimately selected," he states.

Vaughn points out that directional and extended-reach drilling will no doubt have a role to play in the Lower Tertiary, given the scarcity of production infrastructure. "We are evaluating ERD technology to determine how it could be used in our projects, but one question we have not yet fully answered is whether it is better to have dry trees with platform rigs drilling very long extended-reach wells, or wet tree wells drilled vertically and tied back subsea to the producing platform," he posits.

"In time, I suspect we will see combinations of field development scenarios, but one benefit we see with using wet trees and a floater is the ability to predrill wells so they are ready to connect to the platform and start producing as soon as the structure arrives on location," Vaughn continues.

In fact, Vaughn suggests that the wet tree/floater combination is in the cards for the Jack/St. Malo joint field development. Noting that front-end engineering and design work began earlier this year for a production facility sized with an initial daily capacity of 120,000-150,000 boe, he says, "I think we eventually will see a development concept that uses predrilled wet trees so that we have 10-12 subsea wells ready to go before the floating production structure is even installed."

Miocene, Lower Tertiary

The Anadarko-operated Caesar and Tonga West Miocene discoveries in 4,500-4,700 feet of water are being developed jointly as subsea tiebacks to Anadarko's Constitution truss spar at Green Canyon 680. With tieback distances up to 14 miles, 40,000 bbl/d of platform capacity is dedicated to accommodate production from four initial subsea wells. The estimated resource range at Caesar/Tonga is 200 million-400 million barrels.

Within the span of a couple days in early February, Anadarko Petroleum Corp. announced a pair of discoveries in the subsalt Miocene and Lower Tertiary. According to Darrell Hollek, vice president of Gulf of Mexico operations, the Anadarko-operated Heidelberg discovery well was drilled to a total depth of 28,500 feet in 5,000 feet of water at Green Canyon Block 859, finding more than 200 feet of net oil pay in multiple Miocene-age sands. Anadarko's partners on Heidelberg are Mariner Energy, ENI, StatoilHydro, ExxonMobil and Cobalt International Energy.

A few days later, the results came in on the Lower Tertiary Shenandoah discovery, drilled to 30,000 feet TD in 5,750 feet of water at Walker Ridge 52, and encountering about 300 net feet of "high quality" Wilcox pay, Hollek notes. Anadarko is operator, with partners ConocoPhillips, Cobalt and Marathon.

"The Miocene and Lower Tertiary are the two key focal points of our Gulf exploration program. We have a substantial inventory of both Miocene and Lower Tertiary prospects, and we will drill or participate in up to six Miocene and Lower Tertiary exploration tests this year," says Hollek, noting that drilling alreadyhas commenced or is scheduled to get under way on three of those prospects:

- Turtle Lake, a Chevron-operated Lower Tertiary prospect in 5,715 feet of water at Green Canyon 847;
- Vito, a planned 30,500-foot Anadarko-operated well targeting Miocene objectives in 4,000 feet of water at Mississippi Canyon 984; and
- Samurai, another Anadarko-operated exploration well targeting the middle- and lower-Miocene in Green Canyon 432, and located just north of the company's Marco Polo tension leg platform in 4,300 feet of water at Green Canyon Block 608.

Independence Hub

One of the largest and most significant developments in the Gulf in recent years is the Anadarko-operated Independence Hub development in world-record water depths in the Eastern Gulf of Mexico's Mississippi Canyon area. Hollek reports that Anadarko continues to evaluate a number of exploration opportunities and satellite development options for nearby prospects and tieback candidates to the semisubmersible (stationed in 8,000 feet of water at Mississippi Canyon 920).

As a fast-track, 10-field development in 7,800-9,000 feet of water that required collaboration from multiple operators as well as a third-party infrastructure owner, Hollek says Independence Hub already has produced more than 400 billion cubic feet of gross gas since coming on line in mid-2007.

"This single asset accounts for approximately 10 percent of Gulf gas production and about 2 percent of total U.S. gas production, so it is very significant. There are a number of opportunities for satellite developments and tiebacks within our fields (Anadarko operates eight of the 10 anchor fields)," Hollek holds. "We will begin putting those prospects on the drilling schedule to try to make certain we keep the facility operating near full capacity."

Given the high flow rates of the 15 initial wells, Hollek estimates capacity should become available on the Independence Hub to accommodate other regional discoveries within the next 12-24 months. "Completing a subsea well and tieback in 8,000-9,000 feet of water is not exactly routine, but we have done subsea tiebacks so often that we think we have most of the risks managed and can turn a subsea tieback project around pretty quick, once capacity is freed on the host platform," he remarks.

Anadarko is evaluating future exploration and satellite development opportunities for nearby prospects and tieback candidates at its ultradeepwater Independence Hub project in the Eastern Gulf of Mexico. Stationed in 8,000 feet of water at Mississippi Canyon 920, the semisubmersible accommodates production from 10 fields that have already produced more than 400 Bcf of gas since coming on line in mid-2007.

Caesar/Tonga Complex

The subsea tieback option is the development scenario selected for Anadarko's latest "mega project:" joint development of the Caesar (Green Canyon 683) and Tonga West (Green Canyon 726) Miocene oil discoveries in 4,500-4,700 feet of water, according to Hollek. Anadarko operates Caesar/Tonga with partners Shell, StatoilHydro and Chevron.

"This is by far our biggest development project in the Gulf in 2009," he relates. "The estimated resource range at Caesar/Tonga is 200 million-400 million barrels of oil, so these are large discoveries. The fact that we are able to use subsea tieback technology to leverage infrastructure that we already 100-percent own and operate allows us to maximize the value of this project."

The initial development plan includes four high-rate subsea wells drilled to total depths of 28,000-29,000 feet and tied back up to 14 miles to the Constitution truss spar at Green Canyon Block 680. Three wells have been drilled at Caesar/Tonga, Hollek updates. "We are ready to drill sidetracks from two of the wells slightly updip to better take points," he states. "Those two sidetracks will be followed by a grass roots well planned to spud in early 2010."

At the same time, Anadarko is reprocessing seismic data over the development area to determine if the reservoir system extends beyond the two fields, Hollek continues. "The partners in Caesar/Tonga have a solid lease position in the development area, and we very much believe there is more to this structure," he avers. "We could drill additional exploration wells in adjacent blocks in 2010-11."

Anadarko is dedicating 40,000 barrels in daily capacity on the platform to accommodate oil production from the four initial wells. "The ability to develop the fields as subsea tiebacks to the Constitution spar allows us to expedite the project so we are able to get the wells on production much faster while also saving the capital cost of building a new facility," Hollek remarks. "When you look at the risk associated with any deepwater development, there is tremendous upside in being able to minimize the upfront capital requirements while expediting first production and maximizing the return on capital employed."

By shortening the timeline to first production, the project partners also move the clock forward on future appraisal and step-out drilling, he notes. "We think we have a lot more drilling ahead of us in and around Caesar and Tonga West. As the complex grows in terms of resources, we can either lengthen the life of the complex or upgrade the processing equipment aboard the Constitution to increase throughput capacity," says Hollek. "The sooner we can bring the first four wells on line, the sooner we can learn from the data and decide how to pursue future delineation and development options."

Going forward, another possible subsea tie-in to Constitution could come from the Heidelberg Field, located 15 miles from the spar, according to Hollek. "We have only drilled the discovery well, so it is far too early to make field development decisions, but a subsea tieback is certainly an option, given Heidelberg's proximity to Constitution," he explains. "On the other hand, we will drill at least one appraisal well at Heidelberg this year. There are numerous prospects in this general area, so depending on Heidelberg's ap-

praised size and other successes, we could find ourselves with a whole new development area that justifies its own production facility."

Second Nature

Hollek adds that Anadarko also is preparing to complete two developmental wells at its K2 Field in Green Canyon 518 that will be subsea tiebacks to the Marco Polo TLP, as well as initiate the satellite drilling program in the Eastern Gulf to keep the Independence Hub humming along at near capacity.

"We operate all kinds of facilities in the Gulf and around the world, but there is no doubt that subsea tiebacks have become second nature for Anadarko in deepwater field development. We operate or have ownership in 11 deepwater facilities that span the Gulf, so we are rarely far from one of our deepwater facilities," he comments. "Once a facility is in place, it creates the opportunity for a hub-and-spoke concept to tie in subsea wells."

However, from an exploration standpoint, he adds that the company always seeks to drill the biggest and best opportunities in its portfolio, regardless of any facility issues. That holds especially true for the infrastructure-barren Lower Tertiary play, and it brings Hollek back to the Independence Hub and the lessons Anadarko learned in bringing natural gas to market from those 10 ultradeepwater fields.

"The key thing at Independence Hub is that we were able to bring a lot of fields and operators together in a common field development scenario to the mutual benefit of all parties. It takes an extraordinary amount of cooperation and collaboration to accomplish that, but Independence Hub proved it can be done," he contends.

"There is no doubt in my mind that the industry will figure out how to efficiently develop Lower Tertiary fields," Hollek concludes. "I think we will see independents, in particular, look hard at multifield development opportunities with common production solutions similar to Independence Hub. However, the difference is that the Lower Tertiary is an oil play, and it is harder to pipeline oil over long tieback distances. To make this kind of development work, you need multiple discoveries in close proximity."

Telemark Hub

ATP Oil & Gas Corp. got its start by acquiring "marginal" offshore properties, but as the company has grown over the years, so too has both the size of its projects and the water depths in which they are located. A case in point is the Telemark Hub, a three-field deepwater development that ranks as ATP's largest and most ambitious undertaking to date, reports T. Paul Bulmahn, chairman and chief executive officer.

"We originally pursued a strategy of developing fields that were marginal to larger companies. Over time, we were able to focus less on the marginal fields of exploration companies and more on their nonstrategic assets that were very good discoveries with attractive quantities of oil and gas reserves, but were not developed for some reason," he explains. "We are very pleased to now be in the position to be able to address a project with this kind of material impact."

The Telemark Hub is a joint development of the Mirage Field in 3,927 feet of water at Mississippi Canyon 941 (discovered by Vastar in 1999), Morgus in 3,960 feet of water at Mississippi Canyon 942 (discovered by Shell in 2000), and Telemark in 4,385 feet of water at Atwater Valley 63 (discovered by Texaco in 2000, originally named Champlain, and subsequently renamed "Telemark" by Statoil). Statoil eventually acquired controlling interests in all three fields (ERT had a minor interest in Mississippi Canyon 941) and ATP, in turn, purchased them in 2006, according to Bulmahn.

The development strategy is staged in two phases, and is using the Gulf's first minimum deepwater operating concept (MinDOC)–christened the ATP Titan–to initially produce two dry tree wells at Mirage, one or two dry tree wells at Morgus, and a subsea well tied back 11-12 miles from the Telemark Field. Bulmahn reports that construction of the ATP Titan (the first deepwater dry tree platform built in the United States) is nearing completion at Gulf Marine Fabricators' shipyard in Ingleside, Tx., and is on schedule for sail-out and mooring this summer.

"The first graving dock for offshore construction in the United States is being used to build the ATP Titan's hull," he notes. "Basically, a pit is dug with a strip of land kept intact to separate it from the Gulf. When hull construction is complete, the strip will be removed and the pit will be flooded so the ATP Titan can float out of the dock and be towed to sea. By avoiding the need to lift a giant structure 750 feet long onto a barge, we are cutting significant cost from the construction

ATP Oil & Gas Corp.'s Telemark Hub is deploying the *ATP Titan*–the Gulf's first minimum deepwater operating concept (MinDOC)–to initially produce two dry tree wells at the Mirage Field in 3,927 feet of water at Mississippi Canyon 941, one or two dry tree wells at Morgus in 3,960 feet of water at Mississippi Canyon 942, and a subsea well tied back 11-12 miles from the Telemark Field in 4,385 feet of water at Atwater Valley 63. In the second phase of development, the *ATP Titan* will move from Mississippi Canyon 941 to Atwater Valley 63 to drill additional wells at Telemark.

process, and this is the only practical way to launch a structure weighing nearly 20,000 tons in a controlled manner."

Sequential Development

The MinDOC will function as both a floating drilling and production platform. At one point, ATP's development plan included two MinDOCs deployed in parallel. However, to minimize cost and complexity, Bulmahn says the company ultimately elected to deploy a single unit in a sequential development scenario. The facility will initially be stationed at Mississippi Canyon 941 to produce Mirage and Morgus along with the one-well tieback from Telemark, and then move to Atwater Valley 63 to drill and produce additional wells at the Telemark Field.

"We are anticipating three or four development wells at Mirage and Morgus (plus the Telemark subsea tieback) in the first development phase, and another three or four wells at Telemark in the second phase," Bulmahn details, pointing out that that the drilling operations will use an innovative approach that is new to the Gulf.

"Drilling will be accomplished with a single-barrier riser backed by a subsea isolation device (SID), which functions as an emergency seafloor shut-off in the event of riser failure," he states. "The SID consists of an 18¾-inch subsea blowout preventer on a subsea wellhead controlled by a surface umbilical."

The ATP Titan has a daily design production capacity of 25,000 barrels of oil and 50 million cubic feet of gas, and Bulmahn says the company anticipates operating it at full capacity when production startup is achieved from all three fields. "The facility has a design life of greater than 40 years, which far exceeds the expected productive lives of the Telemark Hub fields," he notes. "That means this MinDOC can be redeployed to a number of assets over time, providing a huge residual value. To be able to monetize the facility at an early stage allows us to then reinvest those funds to develop other reservoirs."

Bulmahn describes the MinDOC's features as a combination of a semisubmersible and truss spar, offering stability and flexibility over a long service life. "It has a triple-column hull, which not only enhances stability in deep water compared twith a single-column spar, but also provides greater deck space capacity so we can put both drilling and production processing operations on deck and still have room to host third-party production at some point," he states. "We think this design will prove very effective and flexible as the ATP Titan moves from one location to another over its 40-plus year life."

Except for the initial subsea well from the Telemark Field, ATP plans to complete all the wells with dry trees. "It is difficult to estimate exactly how long it will take to deplete Mirage and Morgus in the first phase because so far the reserves on every deepwater field we have touched have grown over time and take longer to deplete," Bulmahn observes. "That said, once we move the MinDOC to Atwater Valley 63, we likely will convert the subsea well to a dry tree as we drill additional wells, because dry trees are much easier and less costly to work over or recomplete."

Two wells at Mirage, one well at Morgus, and the subsea Telemark well have been predrilled to total vertical depths of 5,861-5,881 feet and cased with 22-inch pipe, Bulmahn updates. "They will be ready to complete when the ATP Titan arrives on location this summer," he relates. "Predrilling the initial wells is another way we are advancing the timing of the development to tighten the window between the first dollars spent on development and the first production revenue coming back."

Operating Philosophy

A 62-mile pipeline has been installed to export production from Mississippi Canyon 941 to an interconnect at Grand Isle 115. True to its operating philosophy, ATP owns 100 percent interests in all three fields, the MinDOC facility, and the pipeline infrastructure, according to Bulmahn.

"We prefer an initial 100 percent ownership because it gives us direct control of all aspects of field development, including timing and cost," he offers. "By eliminating multiple interest owners, we can design and execute a development plan much faster, which dramatically increases the rate of return. That is critical for a smaller independent on capital-intensive deepwater projects, particularly during a time like this, when the financial community is experiencing such turbulence."

One illustration of how that control can pay dividends occurred late last year, when ATP adjusted the development schedule to fund the future development cost of the Telemark Hub entirely from cash flow. "The biggest challenge deepwater operations present to a company of ATP's size is the magnitude of capital required for field development. We had Telemark on a fast track, but with the way the financial community had disintegrated, we determined it would be in our best interest to slow the project by a few months to ensure that we could keep all the work within cash flow," he recalls. "Again, we could do that because we own and operate the project 100 percent."

Yet even with ongoing credit and capital availability issues wreaking havoc in the global financial community, Bulmahn says ATP Oil & Gas secured a $150 million capital placement in late February from GE Energy Financial Services, whereby GE acquired a 49-percent limited partnership interest in the ATP Innovator, a converted semisubmersible drilling rig that serves as the floating production facility for ATP's multiblock Gomez Hub deepwater development (ATP holds the remaining 51 percent and serves as managing partner).

Moored in 3,000 feet of water at Mississippi Canyon 711 with a daily capacity of 20,000 barrels of oil and 100 MMcf of gas, Bulmahn notes that the ATP Innovator is GE's first investment in a floating oil and gas production facility. "We are ecstatic to be able to enter a financial partnership with GE at a time when capital markets are exceedingly turbulent, and to be able to monetize a physical asset other than reserves," he remarks. "The ATP Innovator is currently handling only ATP production, but the partnership plans to process additional reserves from third-party producers starting in 2010.

"We have invested a great deal in hub infrastructure in the Gulf, but were not receiving appropriate value for those assets," Bulmahn adds. "To GE's credit, it recognized the value of the ATP Innovator and already has expressed an interest in possibly adding the ATP Titan to the partnership." ❐