BOEM DEEPWATER GULF OF MEXICO HISTORY PROJECT

Interviewee: Robert Patterson

Date: August 28, 2009

Place: Houston, Texas

Interviewer: Jason Theriot

Ethnographic preface: Robert Patterson grew up just south of Jacksonville, FL, and he remained in his home state to attend the University of Florida. There he earned a terminal Doctoral degree in engineering science and mechanics. Patterson abandoned his initial aim of becoming a professor after a chance encounter with a Shell employee, and he soon joined up. Some of his early work included designing catenary pipeline arrangements for steel risers, to hang off of a floating structure. That work took Patterson to the deepwater Gulf of Mexico, where he worked on the Auger tension-leg platform designing its novel production riser and tensioning systems. Patterson later worked on the Mars TLP as well. In the late 1990s, Patterson was instrumental in the re-formation within Shell of a Deepwater Projects division.

File 1

JT: Okay, we are here with Robert Patterson on August 28, 2009. We are at Shell Creek's facility. The interviewer is Jason Theriot. This is for the MMS Deepwater Project and we are talking about Shell Deepwater. For the record, Robert, what is your current position here?

RP: My current position is Vice President, Upstream Projects Americas. That's just a recent change. I was a manager of Deepwater Projects. It's related. The current scope includes deepwater in the Americas plus onshore unconventionals and wind and other things. In the prior role it was to ensure we were doing deepwater projects in a consistent way globally, including other deepwater provinces around the globe.

JT: That must have been a fairly recent changeover.

RP: It's very recent.

JT: Because I was here a couple two or three weeks ago with Doug Peart and he said that you were in charge of deepwater in the west, meaning the west hemisphere.

RP: That's right. So this is a change. Actually, this is August the 28th, so it happens on September 1st.

JT: Oh, okay. Good, good. Well, congratulations on the new task at hand.

So tell me a little bit about your background, where you're from, the town you grew up in, and some of your academic training before we get into your profession in the industry.

RP: I was born in Austin, Texas, but I grew up in Orange Park in Florida, which is a small town south of Jacksonville, Florida. I went to the University of Florida, where I earned a bachelor's, master's and Ph.D. in engineering science and mechanics. Most of my work there was around things like robot touch sensing. But I was fortunate, a bit before I finished my degrees, a really remarkable fellow from Shell came and found me working in my office and showed me the really neat things they were doing. So I just wrote a letter to Shell. My intention was to become a professor. But I had this person who came and visited me and I was really struck by his energy, his creativity, and really the scale and scope of what was being accomplished. So I wrote to Shell and I ended up joining Shell as a researcher.

JT: What was that fellow's name?

RP: His name was Carl Langner. You may have him in your interview list because he has a number of the patents that have been key to unlocking the deepwater, especially in the pipeline area and umbilical area, and he won an OTC Distinguished Achievement Award a few years ago.

JT: He's next on my list.

RP: Okay, well, say hello to Carl for me.

JT: I will.

RP: We ended up working together when I first joined Shell and then having a chance to work together again a few years later when I went back to R&D. So that was the path to Shell. I thought at first I would work on the Arctic in the mid-eighties in research, but when I arrived, there was some excitement about possibilities in the deepwater. My first project was to study was it possible to hang a steel pipeline off of a floating structure in a catenary shape, and that research work led to us deciding that steel catenary risers would in fact be a possible way of transporting hydrocarbons from a floating structure and could work in the Gulf of Mexico. That led to an opportunity to join the Auger project, so the first deepwater project that we undertook.

JT: Before that, backing up, had you had any prior experience in dealing with offshore projects of any kind or onshore or near shore, other than the Arctic stuff?

RP: My first opportunity of getting involved in a project and bringing technology to it and then carry it through to execution was Auger.

JT: How old were you then?

RP: Well, I joined Shell, I was twenty-seven. I was with the Auger team for maybe six years. So, before it was called Auger to realizing it. I probably have a picture of some of the kit from Auger in the other room. I can show you afterward.

JT: So these were the groups that were developed and you were part of one of those research groups.

RP: So I was part of a research group that was working on technology. Then as a team was being formed to come up with the final concept for Auger, I moved to a group that was called Head Office Civil Engineering that was led by Pat Dunn. He may be on your list as well. In particular, a group led by Lee Braestadt [phonetic], who may also be on your list, was key in the civil engineering area.

I worked on what was a relatively new part of a structure and system that represents the change from fixed platforms to TLPs. That was the well systems area, where you had production risers that now would move and need to be supported in a dynamic way with tensioning systems. So I was very fortunate then. I moved from the Civil Engineering Group to our Shell offshore organization in New Orleans to work on those well systems, but the structural dynamics parts of it and then the equipment that we actually used at Auger.

JT: The team concept or the group team concept, was that something relatively new in the development of Auger or was that something that Shell had used before in other offshore projects?

RP: You have to appreciate that was that my early days, now quite a while ago, but those were my early days. I think that that approach of how teams came together on special projects, Cognac and Bullwinkle before Auger, but Auger was a real step. I mean, that was a dramatic change. That team really had to bring even some new skills and capabilities and technology. Quite a few people from the technology organization moved into the engineering and projects organizations to help realize Auger. Even today in our engineering and projects organization here we have many of the people who came from the research organization with academic backgrounds, strong academic backgrounds and technology backgrounds, and took technology and applied it and have stayed with our projects ever since.

JT: So the issue about the wells was because whereas before, with Cognac and Bullwinkle, the risers were in a fixed position, encased by a fixed platform, here they're going to be moving and floating along with the production facility.

RP: That's right. So they're not supported along their length. They're just held up at the top, they're in tension, and you have to keep them in tension so that they don't buckle at the seabed, but they have to move a lot. So you go to analyzing a dynamic system, and the key challenge was to see could they stand a long life and could we really confidently predict their fatigue performance and know that they could handle both the extreme motions, extreme weather loads, but also the long-term motions that would cause oscillating stresses.

JT: Now let's back up to was there any literature or research or projects that had used this type of floating riser technology? What were you guys basing the new technology off of?

RP: So there were analysis programs and studies had been done. So for drilling rigs, they already operated with risers that were supported from the top. There had been a TLP built in the North Sea called Hutton, in not so deep water, but it was a TLP. But still at that time, it was early days. I remember for actually analyzing the Auger production riser systems, I believe I used about nine different analysis tools to try and get at the different issues, issues whether it's dynamic motions, it's fatigue. The riser system has a tube inside of a casing inside of an outer casing. Actually, the production riser is made up of three tubes. So to analyze how those tubes interact, to analyze whether the risers, which were unsupported, but unlike drilling, they're in close proximity to one another, would they interfere with one another or bang together, took about nine different programs. Today all of that's integrated in one capability and we can do in days what took me years.

JT: So, a riser. Let's say you've got your wells, let's say you've got twenty-four wells, which I think Auger may have had.

RP: Auger had thirty-two well slots.

JT: So does each well have a riser?

RP: Yes.

JT: So you had to have thirty-two risers and riser connections within that bay on the inside of the Auger platform.

RP: That's right.

JT: So thirty-two independent systems?

RP: Thirty-two independent systems. I'll have to show you some pictures here. When we come out of the room, I'll walk you around and show you some pictures to give you a feel for it.

JT: Prior to that, like the one TLP in the North Sea was that maybe a Conoco?

RP: It was Conoco, yes.

JT: Were they using the same type of setup with these independent riser systems?

RP: Yes, they did. Theirs were in a matrix pattern. Auger, as our first step, had some unique characteristics, some of which we repeated and carried forward into the other TLPs and some of which we changed. The driving force at the time was to try and use as much of proven capability as we could and only bring new technology where that was absolutely required.

So Auger has a unique system for using a subsea BOP system, but a surface tree system, so trying to have production systems that were like fixed structures and having a drilling system that was like floating drilling. That led to a very large moon pool area in the Auger TLP, with production risers supported around the perimeter of that moon pool, a drilling riser that was able to be lowered in the middle of that moon pool, and then, because the rig was in the middle of the moon pool, if you think about a production riser that will eventually be put at the perimeter, we had a mooring system on Auger that allows you to pull the whole platform over a well, run the production riser, bring the TLP back to a neutral position, and then at the entry system, take the top and move it into a slot, a very unique well systems-handling capability. Bill Petersen [phonetic] was the guy that really was behind and led our Well Systems Group there, a fantastic engineer.

JT: So the work that you guys did influenced how this TLP was going to be built, if we're talking about the bay area and having the production risers along the perimeter.

RP: Right.

JT: So you were in direct communication with the designers.

RP: Yes, so the deck had to be designed to support what we were doing and then we designed the hardware that was specific to the well system, so the tensioning system, for example, that allows for the riser to move. Because what happens now, as soon as you go to a floating system like a TLP, instead of in a storm moving, let's say, the top of a fixed structure moving inches or a couple of feet, you're now moving as far as a football field, and the platform moves differently than the production risers do, so you have to allow for a lengthening and shortening in the tensioning system to accommodate differential movement. So we had to design a system that would allow that, but also could be cantilevered from the perimeter of this well bay. So that was unique, and we learned some things and we did things differently as we went to Mars and improved quite a bit from Auger to Mars, but the initial application was there at Auger.

JT: Let me ask you two questions about that and we'll move on. What was your specific role with the risers in Auger? You had mentioned that you guys were using some existing technology, but then you had to actually create your own technology. Without going through the whole list, give me maybe the most significant of the new technology that was involved in that well systems at Auger.

RP: So my specific role was in the design of the production riser system and the tensioning system that held the production riser system up. The key technology in that was an elastomeric tensioning system, so a tensioning system that uses a lot of rubber and air, no hydraulic fluid to hold it up in what we called a rocker arm configuration, so an arm that is extended out from the side of the well bay, supported by rubber and air ram-type devices that allow this arm to go up and down. So the key technologies in that were the rocker-arm tensioning system itself, another elastomeric bearing between the production riser and the rocker arm that allowed for very large angular movement, and then it was, I'd say, a lot of creation of analysis capability so that we could be confident in the longtime performance of the system.

JT: Where did you guys test this initially?

RP: So the rocker-arm tensioning system was built by Vetco and we built a full-scale segment of the well-bay area that accommodates one well slot and built a full-scale rocker-arm tensioning system.

Let me just take a break here and get you a picture.

[interruption]

RP: So this is the tensioning system looking from below, and this is actually a full-scale test setup which includes the shoes at the base. So to install this system offshore, it had to be handled by this well bay entry system I described. Then in order to bring a riser into this slot that you see here, you bring it in, you have to lower the arm to grab the right point. To do that, you have to compress these rams. We did that by having them loosen and sliding them off a ramp so they would be in compression. We had within the system also some titanium bearings with ceramic coating that don't need any grease. So you have a system that was no maintenance, with elastomers, greaseless bearings, and then the bearing that you see in here. So you can picture as a rocker arm does this, there's a big angular difference between that and the riser. This tensioning joint had to be created, a stress joint at the base to accommodate. So as you go to the seabed, you don't have rotations; you have to take out your deflections through bending so you have to design a tapered stress joint to be able to manage that bend with acceptable stresses so that you don't damage the components in any way.

JT: The riser production pipe is coming up through here?

RP: That's right. So with what you're looking at, this would be at the top. This is Auger that we're looking at here. Within the well bay, this is held out. The tensioner joint, so we tested that here as well, that's what you see here with this anticorrosion coating on it. The Christmas tree sits here and then the pipe runs, in Auger's case, 2,800 feet to the seabed. What this is, is the outer casing. Inside of that is a seven-inch production casing, and inside of that was three-and-a-half-inch tubing at Auger.

JT: You had thirty-two of these?

RP: We have thirty-two of these.

JT: That's fascinating. Was this at the Vetco manufacturing—

RP: This was at the Vetco facility here in Houston at North Houston Rosslyn. So at that time it was AVB Vetco Gray. That's now part of General Electric.

JT: That's fascinating.

RP: So that was a key part of well systems. If you think about Auger as a whole, the whole well bay handling system that's created is unique and only it was done at Auger, but that was technology and that had a major test program. The tendon system had some threaded connectors and large flex elements at the bottom that were also created at that time. Now all those things are pretty normal business. The steel catenary riser systems for export was the first application at Auger and that's commonly used in deepwater applications today. Those at least stand out from my experience there.

JT: How have these what I would call souped-up shock absorbers, that's what it looks like, how have these withstood over time since the nineties, well, fifteen years?

RP: So there have been some challenges with them, but they're still in use. But we've learned a few things about the systems over time and actually have adapted different ways of using the systems. You can see at the time, if you look carefully at this, we weren't 100 percent sure about how these would really stand up for thirty years, which is what we were trying to aim for. We did as much testing as we could of the chemical resistance and the fatigue resistance of the rubber on small scale, then at large scale. We tested halves of this, the dynamic. But still you couldn't really account for real-world conditions.

So if you look at the bottom of this rocker arm where these are attached, we also had other attachment points so that beside this rubber element, we could have a hydraulic element that could come in here. That ultimately turned out to be very helpful because we put in some new systems for exporting gas that we actually set up with hydraulic elements and they were able to use these contingency locations.

JT: Let's talk about that a little bit, because you had mentioned about the export production risers, which is separate from this. How did that technology fit in with the Auger design, the exporting process?

RP: So what that allowed to happen, if I refer to this picture, is a fairly simple pipeline system. Essentially they lay right up to the structure and it allowed the connection to be at the pontoon level and then piping to come up the column into the production area. It allowed for a fairly simple lay and handover and connection system and helped to lower the costs quite a bit versus trying to have a pipeline come from within the well bay area and come up to the surface and then make a seabed connection underneath the TLP. So there would have been a lot more hardware and costs and considerations to take into account. But ultimately, we did add an export line and did manage to do that from within the well bay area off of one of these.

JT: So in other words, this was a riser from your production line. You had a Christmas tree on top. It connected some kind of way to the export—

RP: No, so this production will then come into the topsides facilities. So this is going to be your well fluids coming up, so that will be processed. Then the ultimate export oil and export gas will come back down along the columns, across the pontoons, and then enter the export lines that are just hung in a catenary configuration.

JT: Those eventually are laying on the seabed and run all the way back to shore.

RP: That's right.

JT: That's fascinating. Now, with Auger, you guys were obviously after crude, but the way that I understand it, there were some large gas discoveries along the way or was there more gas than you folks anticipated? How did the increase in gas and then, of course, the increase in oil production, which came fairly soon after it was in operation, how did you manage to manipulate the facility to incorporate the new—

RP: Well, you'll get perhaps a good insight on that from Jay Smith as to how we adapted within the topside facilities themselves. I can tell you that one of the challenges that we had just in this simple area is that much of the design of the production riser was thinking about the well fluids and how to keep the well fluids warm so we wouldn't have wax or hydrate problems within the riser system. When we had better production rates than we thought we would have when we were designing this system, we actually got much warmer than I thought, and that meant that this lengthened because of the temperature differential. So, fortunately, we were able to accommodate that change in length of the production riser system because of the tensioning riser system that we've got.

JT: Interesting. How much did—just a couple inches, but that was probably enough to make a big difference.

RP: My memory's a little fuzzy, but I'm going to say it was six to eight inches. But this was designed to accommodate a motion in storms of three feet down and one foot or two feet up, I think it was.

JT: So once these were installed on the facility, did you have to go offshore and make sure that it worked?

RP: So for me, the people who were working with me on the team continued with that. These were actually installed at McDermott's yard in Amelia, and I was with it to that point, had worked on the procedures for how to install all of this, but I had moved over to the Mars project just before startup.

JT: When did you become aware of the Mars project, and do you remember exactly when and at what part of the design of Mars did you jump aboard?

RP: Well, I was able to be a part of some of the considerations on Mars fairly early on just because I'd been working on Auger and we were learning across. I don't recall exactly when that was, but part of what we were thinking about were some changes in the well bay area and the well bay system and could we make those work. Ultimately we did make some significant changes for Mars. We were also, early on, thinking about what was the right concept for Mars. Was it a compliant tower? Was it a TLP? How big should they be? And we were beginning to think about whether subsea might be an option for some later phases of Mars. So lots of options were on the table for what was the best way to develop Mars, and I had a chance to contribute a little bit to that while I was working on Auger.

By the time I moved over to the Mars project, it had been decided that we will be moving with a TLP, but there were aspects of the TLP concept that were still under consideration. An example of that was how we might provide for future fields in the area. One concept was that we would have space within the TLP area for a self-standing riser. So, just before Mars there was a project by Placid Oil Company in Green Canyon. I've forgotten which block it was on. It was called a freestanding riser, where a group of risers came up in a bundle and were supported by syntactic-foam buoyancy and stood by itself and then had flexible lines at the top of that that would take it up to a floater. Then all the connections to that came in via subsea. So that was one option that we considered within the well bay area.

Ultimately, we thought that would be a very large upfront expense with a lot of complexity for providing for future fields. We, instead, created flexibility in the Mars TLP by putting attachment porches, we call them, for steel catenary risers along the pontoons. So we have many more locations. So we've done the export system at Auger from the pontoon, but that was all. At Mars we put in a large number of porches along the perimeter of the pontoons of the hull in hopes that we would be able to bring in future fields, and ultimately those were used for things like Europa and Crosby. I think about the other tie-ins that have come into Mars and allowed Mars, I think, to be probably the first real regional host in deepwater. So at least for us, the first time that the thinking was both about developing Mars itself but thinking to the future of a wider development area, having infrastructure to do that. But how do you do that in a way that you don't spend an enormous amount up front but you have flexibility?

JT: Was there one individual in particular who influenced those decisions about taking a TLP concept, adapting what you learned from Auger, building a facility, but then, wait a minute, what if we want to expand it and expand the fields in the future to give us those opportunities, let's spend the money up front. Was there someone who was thinking about that and who was persuading the upper management to take a considerable look at that?

RP: Well, I think it was, from my perspective, a pretty collaborative effort between the project manager and the subsurface teams, but also a very engaged senior management there, Gordon Sterling and Rich Pattarozzi, helping to drive the tensions of how do you have a development you can actually go forward with commercially, but also think about the longer view. And that put enough tension for us to find a good solution to that. The first solutions, I think, were not the best solutions, and so the tension of continually pushing to find a better way was collaborative but definitely driven by Rich Pattarozzi and Carl Wikizer, Gordon Sterling, and others.

JT: So what was your role on Mars? Was it somewhat similar to this?

RP: For Mars, I was only with that project for a short time. What I worked on was the potential for a subsea tieback north of the Mars platform, which would be the first oil subsea development for us in deepwater, and it was really to prove up could future developments be subsea in the area, because oil presented some extra challenges in how could we manage the flow assurance challenges in particular and then, if we had problems, could we access and deal with those problems if we had a hydrate problem or we had a wax problem or we had an asphaltine problem. So I had a chance for a while to work that subsea tieback that is north of Mars and bring that in and come up with working with other solutions for retaining heat and managing the flow assurance challenges.

Then, ultimately, that activity came over to Doug Piert's subsea organization at the time. I moved back to R&D, marine R&D, and had a number of people in that organization that supported Mars from the technology side working in the production riser systems, working in the export systems, and continuing to support the subsea system in how do you create the right building blocks, how do you provide the right heat retention for the challenges that we were facing then at Mars.

JT: Let's talk about that first oil subsea. I understand that there were some gas subseas, like at Tahoe, I believe.

RP: Yes.

JT: So you guys were probably working off of the data and the production off of that to develop oil subseas, is that right?

RP: Well, Tahoe hadn't started up at the time that we were doing the design work for Mars, so the oil properties and so on that were influencing what we thought we needed to provide, to cater for in a deepwater oil subsea system, were coming from the test wells at Mars.

JT: What about the actual technology to go to actually build something for oil subsea? Was that something that Shell had been working on for a while?

RP: We had, but this provided the first implementation, and so it helped to bring what had been a strong and active program in the areas of wax and hydrates and asphaltines, in particular, and bring that together into what will that mean for a system that can actually perform. It was actually accomplished by others. I only was there for a period of time. But I think it really helped to pave the way for a future in subsea. Of course many, many more wells now are subsea than are with direct vertical access. But at the time, I think there was a lot of uncertainty about how well we would actually operate wells subsea.

JT: Had anyone else done a subsea oil well up to that point?

RP: In shallower water, but I think that was the first in deepwater.

JT: So you moved on to more design specs for Mars. Tell me a little bit about moving from the subsea aspect to the actual design of Mars. Then what was your next project?

RP: So, for me, I moved fairly quickly back to the technology, R&D, so I didn't carry forward with design efforts on Mars itself. So I moved to become the manager of Marine R&D, and that group worked on pipeline solutions, subsea solutions, production riser solutions, supporting Mars and future deepwater projects. So we were already looking ahead to supporting even larger systems at Ursa and how would we go deeper.

JT: Let's talk about pipelines, because that's one area that we don't know a whole lot about and I'd like to know a little bit more. What were some of the big questions about deepwater pipelines that you guys were studying in the research area?

RP: So the challenges were how to install pipelines in very deep water safely and cost-effectively. So in shallower water, lay barges have a stinger that comes off the back. The inventor of the articulated stinger, which allowed us to go from, say, 100-ish feet of water to 800 or so feet of water, is Carl Langner, who you'll speak to. So pipe was made horizontally on a lay barge, we'd come across the stinger and come down to the seabed. As you get deeper and deeper, you almost can't handle that load, so you just have very high tensile loads from a hanging pipe. You can't manage that across these stingers, so techniques like j-lay and reel-lay were what we were working on for installing. And then making sure that once they could be installed and cost-effectively, could we manage that, on what kinds of vessels could we do that and how do you make the connections and so on, those were big challenges. Carl Langner is going to be able to tell you a lot about that because he really was instrumental.

In this group, in terms of applying it in the field, Franz Kopp [phonetic], who is just down the hall here, can also tell you. He was the project engineer and actually installing and putting it out there. So you had great ideas from Carl and great implementation by Franz.

Other challenges that were worked on in the flow line area were, first, around heat retention, insulation, and so on. Later we worked on could we electrically provide heating on the seabed, and ultimately applied a pipe and pipe electrical heating solution at Serrano and Oregano, and that migrated to a system where you could apply heat if you needed to. We call it electrically heated ready flow lines. That was applied at Na Kika, when we did the first ultra-deep.

Other challenges were in subsea umbilicals. Prior to Popeye, subsea umbilicals, the individual tubes within an umbilical were made of plastic and that had pretty low collapse resistance to external pressure as you went to deeper and deeper waters. So the team there, led by Carl again, came up with a helically wound metal tube umbilical, first applied at the Popeye subsea field, but ultimately a part of all of the umbilicals that we've had since. If we take another break, I'll show you that.

[pause]

So the other area that was important thinking then ultimately the subsea group that Doug Peart led over time really was able to put into practice and then especially working together with FMC over time, but their early work on how do you make simpler connections between components on the seabed. In the early days, in shallower water, the way connections were made was either with guidelines that would come down from the surface that could guide equipment to a certain location, or you'd take and move flow lines on the seabed with big pulling devices. So as you go deeper, that becomes even more expensive to try and do because you have to build everything with much more massive steel just to withstand the pressures, but then you also have to overcome those pressures for your controls. Then you also end up with equipment on the seabed that's bigger, you try and move around. So all that works against you.

So a concept of stab and hinge-overs, the idea of jumpers that have hydraulic connections, now these are standard building blocks, where trees have a outward-facing hub and you lay a flow line down on a sled and you have a hub there and you come in and just lower a jumper that connects them. So all that early thinking was going on in the early nineties and now that's become really a standard way of doing business.

JT: All that is operated by hydraulics on the—

RP: No, by ROVs that come in and control at the seabed. So everything was ROV-friendly.

JT: So basically it's almost like a working industrial park down there, with machines that are doing the work that divers used to do.

RP: Yes.

JT: And those machines are being operated by ROVs.

RP: Yes, so there's not really machines. I'll walk you around and show you some of that hardware. What you'll see is what you have are components that match up and connect, and the connections are operated by hydraulic pressure that are managed by the ROV.

JT: Lots of different technologies are working around the same time in the 1990s.

RP: Right. Still today as you look at the Perdidos, it's all finding the right technology to match into what you know will work so you can have some confidence that you do it, but each step forward takes some new thinking, some new ideas, and finding a way to fold the new in with something, existing capability really is what the march to deeper and deeper waters has been like.

JT: So from Mars, how long did you stay at the technology area?

RP: So I was there about three years. Then I moved back to New Orleans again, in deepwater development planning, so looking at how we would be developing areas in the Gulf of Mexico and then what kinds of concepts should we be applying in those areas. Na Kika is an ultimate product of that, where you had one of the first—I mentioned that Mars was the first one where we had a host on top of a field that was thinking about a region. Well, Na Kika was the first one that was in a region but not on top of a field, and you ended up having several fields that came in together to one piece of infrastructure. Now there are a couple more of those in the Gulf of Mexico that are like that.

After that we formed Shell Deepwater, which allowed us to take the engineering and project management capability built up in the deepwater Gulf of Mexico and make it available for deepwater areas in other parts of the world.

JT: And you were a part of that thinking and the development?

RP: I was part of working that out and a part of that. I led our subsea and pipeline organization at that time. Then I had the opportunity to go to Norway to work on the Ormen Lange Field. It's a major deepwater gas field off of Norway that supplies gas to the United Kingdom.

JT: The deepwater department, whatever you called it, what year was that established? Shell Deepwater.

RP: It had a couple of different names over time. The Shell Deepwater Development Systems, if I recall, was in about 1998, and Shell Deepwater Services, where we then integrated the wells and subsurface and that capability, I believe, was 1999.

JT: All this was out of New Orleans?

RP: Well, it was Houston-New Orleans, so we have capability in both cities. Along the way, we opened up a sister company in the Netherlands, which helped to make the global connections for us.

JT: So did you get to work on that North Sea project?

RP: Yeah, I was the technical director for Norsk Shell at the time. It was at the time we were selecting what kind of development concept would we have. The development operator foreman on that was Norsk Hydro. Now it's StatoiHydro. Norske Shell was a partner in the development phase and is now the operator in the operations phase. My role is the technical director and we were working with Norsk Hydro and the other partners on should we develop that field with a TLP, should we develop that field with a floater, should it be subsea? It ultimately became a very long offset subsea-to-beach solution for a gas field.

JT: So nothing on the top?

RP: Right.

JT: Wow. Is it the first time anything like that had been done?

RP: Well, Mensa in the Gulf of Mexico was a very long offset subsea development, also very dry gas and very deep water. It doesn't go all the way to the beach, but it went a very long distance and it helped to prove up ultra-long-distance gas subsea tiebacks. So it was a precursor. Ormen Lange is a very large implementation in a very challenging setting as well. But it was part of a plan. I went to Norway and a few others went to Norway to be part of the organization there. See, there was a great connection with what had been built up in the Gulf of Mexico deepwater development.

JT: This is kind of a broader question, because I don't want to take up too much of your time. I have just a few more questions. But the deepwater is established in the Gulf of Mexico, that technology is exported all over the world up until today. But as you mentioned with Mensa, the ability of a strictly subsea system to run back to shore but to tie into an existing platform somewhere along the continental shelf, talk a little bit about how important and how significant the early infrastructure, the early foundation of the outer continental shelf platforms, hubs, and the pipeline system that's built all throughout particularly coastal Louisiana, how important that was to expand in deep water, making it economical.

RP: It really was an enabler, and I think it's one of the reasons why the Gulf of Mexico became such a prolific deepwater province is because there was infrastructure to tie into. If you look at other deepwater areas where there's not infrastructure, you end up with different development solutions. The geology is also a bit different in the Gulf of Mexico, which drives what development solutions are in the Gulf of Mexico versus other areas. That pipeline infrastructure provided access to market, it provided, I think, cost advantages, and it provided some flexibility as to where the hydrocarbons could go. I think all of those are real advantages enjoyed by operating companies, and customers, really, in the Gulf of Mexico area.

JT: The salt domes, too, for storage capacity. To my understanding, some of the crude from Mars was piped into an underground storage area.

RP: I remember the plants, but you'll have to ask—I don't know who else you have on your list. Dan can answer that.

JT: To compare to maybe North Sea or West Africa, where you don't have that historic infrastructure in place, it lessens your opportunities and it probably makes it more expensive, I would imagine.

RP: Well, it at least causes you to have to come up with different solutions. The North Sea has infrastructure, but the deepwater discoveries are really in the Norwegian Sea, are actually far away from that North Sea infrastructure.

The West Africa opportunities didn't build off of a shelf system in a significant way. So you see a lot more floating storage and offloading solutions. And also the market is a distance away, so much of that's exported to other places. So it's a good solution for those provinces, but the infrastructure here provides that access to market, provides flexibility, and helps to reduce costs.

JT: What about Brazil? Do they have a long-term existing onshore infrastructure?

FP: The development solutions there have been primarily floating production systems with offloading as well. So, more like the other areas.

JT: So the northern Gulf is really unique throughout the world as far as its historic development, the infrastructure that was in place onshore, and how that influenced the movement offshore.

RP: Yes, if I think about some other areas, some deepwater areas are not so far from shore. Those in the South China Sea are not quite as far from shore and access to some infrastructure. So each area has its own characteristics, but certainly the Gulf of Mexico has some real strengths with infrastructure that was already put in place. And you see that thinking in the newer developments, where almost all infrastructure that goes out there has some thinking about the future.

JT: Interesting. And possibly even new technologies such as wind. Moving forward, do you see any possibility of looking at wind development from that perspective of what existing infrastructure do we have in place as far as building a new wind system either in the Gulf or along the Gulf? It seems that it's a fabulous concept, but there is no infrastructure in place to send that energy on to an electric power plant of some kind. Those challenges are even greater offshore. I mean, you'd have to completely redesign something.

RP: Yes. So, wind, whether it's onshore or offshore, typically the wind-intense areas are far from where the population areas are. So you have to think about how do you create the infrastructure that allows that development to happen? But the parallels are similar. But in the case of our industry, you had a march offshore that wasn't far from the onshore oil and gas worlds in Louisiana and Texas and the refinery and chemical infrastructure that was present, and that infrastructure kept moving and marching out and providing a way to market with product. You think about wind or other alternative energies, it is, I do think, a piece of the challenge for all of us in realizing those opportunities or how do we get that infrastructure in place that allows the incremental addition of energy production in an effective way.

JT: I just came back from Copenhagen, Denmark, and when you fly in on the bay, it's just covered. Then we stayed in a hotel, we were up on the top floor and there's literally hundreds. They get 20 percent of their energy from wind. It seems like these windmills are powering up this 800-year-old city, this huge city that's built up. Sometimes the turbines weren't moving as much as they were the day before. But I just came back from Corpus, and they've got a similar form out there and they're getting ready to plug it into the system. They get a big breeze right there in Corpus Christi. So it's interesting. Do you foresee maybe as your new role in kind of working around—

RP: I'm going to have to interrupt and just start walking you out because I have another appointment. We can talk about it on the way down. I want to show you a couple of things.

JT: Well, let me say thank you and turn this off.

[End of interview]