NOV’s pressure control research and development (R&D) laboratory is in a tall factory building with a row of large, thick-walled booths used to test how blowout preventers (BOPs) perform at extreme temperatures and pressures.

During a tour, NOV’s R&D Lab Manager Roger “Dale” Brown made a point of stopping to open a small electrical box. Nearly all of the 24 slots inside were filled with cartridges, each about the size of a deck of cards. The circuits inside them allow engineers to gather whatever sort of data they need from BOP tests and send it along to NOV’s central data recorder.

The box is a tangible sign of the industry’s growing appetite for data as it seeks ways to reduce risk, increase efficiency, and pare costs. For Brown, it represents a big change from how things were done just 5 years ago, when the only data available often were just printouts of spreadsheets and graphs of pressure test data stored in a file folder.

Having a deep pool of data is “like a different set of glasses,” he said, adding that, “I am asking questions I never asked before.”

At a time when sales of stacks of subsea well control equipment as tall as an office tower are all but dead, BOP makers such as Cameron, GE Oil & Gas, and NOV are all working on developing digital tools to address pressing problems facing customers. An issue for some is the well control rule from the US Bureau of Safety and Environmental Enforcement (BSEE), which requires deepwater operators to gather real-time data from the BOP control system and come up with a way to do real-time monitoring where offshore data can be observed by expert advisers on shore.

“One of the things we are pushing for is an extra set of eyes onshore, the ability to bring expertise from other areas and provide technical support as issues arise,” said Doug Morris, chief of the office of offshore regulatory programs for BSEE.

Technicians working at the control desk of BP’s real-time offshore drilling monitoring center in Houston can draw from 25 screens with data and images showing operations in the Gulf of Mexico. Photo courtesy of BP.
The value of monitoring programs will depend on the quality of information that can be extracted from a growing flow of data, and the ability of those onshore to build relationships with drillers who trust that the advice is useful.

Data use by Shell, which was a pioneer in real-time monitoring, evolved over time. It was initially “used for post-mortem analysis, and people realized there is value if we get out ahead of this,” using early warning signs to avert potential problems, said Lt. Kyle Carter, a technical adviser at the US Coast Guard’s Outer Continental Shelf National Center of Expertise.

Carter studied real-time monitoring while he was a graduate student at the University of Texas at Austin (SPE 170323). His comments reflect his thoughts and research, and should not be taken as representing the official views of the Coast Guard, whose responsibilities include regulating aspects of oil and gas operations offshore.

While BSEE’s mission is to reduce threats to safety and the environment, the future of deepwater exploration depends on finding ways to sharply reduce costs.

The potential financial rewards for investments in monitoring and analysis include designing and manufacturing more reliable equipment, reducing the time lost due to equipment failures by more accurately predicting when parts will fail, and reducing maintenance costs by moving from time-based repair schedules to systems based on actual wear.

“We are at start of a data revolution in the oil and gas industry,” said Eric van Oort, a professor of petroleum engineering at the University of Texas at Austin. “We now see that we have data, need more data, and have a bunch of data issues we need to take care of.”

The professor who established a network of real-time offshore drilling control centers when he worked for Shell is now advising regulators on how they can do their jobs more efficiently, such as observing offshore testing at a real-time monitoring center on land, rather than flying out to a rig.

Satisfying the rule requires companies that do not already have real-time monitoring to create a plan to create a secure, reliable system to gather and share data on the state of the BOP, as well as on fluid flows and downhole conditions, with onshore personnel. This requires creating a secure connection sending data from an offshore drilling rig to an onshore observer who does not have to be in a central location.

Cameron is running a pilot project on an upgraded system that collects data at a higher resolution; compresses, transmits, and stores data; and enables remote, real-time monitoring on displays like those used on the rig.

Security is also an essential element in these systems. GE’s control and data collection systems are designed to isolate critical well control equipment, so data can flow out but unauthorized users cannot get in and take control.

These extra sets of eyes must be married to more analytical brains to turn the data into useful insights.

“The BSEE well control rule is viewed as a catalyst that will drive remote, real-time monitoring of the BOP control system, which will normalize the practice and will lead to more intelligent systems,” said Zach Hrabak, product line manager for Cameron, who is working on condition-based monitoring systems. “Collection of data and analysis will reduce unplanned downtime and drive equipment design optimization with the ultimate goal of reducing nonproductive time for our customers.”

Drilling is following a path traveled by other industries. For example, GE’s drilling division is drawing on the experience of the company’s jet engine division, which is constantly tracking the condition of its engines on jets around the world.

Data-sharing is a common practice for airlines, but not for rig owners who generally consider it proprietary information. GE worked around that barrier with a deal that is unique in the oil business giving it control of the BOPs used by a drilling contractor. Under the contract with Diamond Offshore, GE bought back eight BOP stacks, then leased them back to the offshore driller. The service agreement gives GE access to the data and equipment maintenance as part of a deal where GE gets paid only if the equipment performance meets certain standards.

While this is similar to leasing jet engines to airlines, in the offshore oil business the drilling company normally works closely with the oil company that plans the well and pays the bills.

“Honestly, it has been a big learning experience. It (a leaseback) has not traditionally been done in this space,” said Bob Judge, director of product management for drilling at GE Oil & Gas. Collecting data over long periods of time marks a significant change in a business where “we have no historical record of how BOPs are operated. We do not know how many times it was used, and what happened yesterday, and what happened before it failed.”

Blowout Drives Change

The Macondo blowout in 2010 that destroyed Transocean’s Deepwater Horizon rig pressed BP into a role at the forefront of this industrywide change. The company created a real-time monitoring center tracking drilling with experts elsewhere following other offshore operations. Other groups in BP helped develop a well control condition display with NOV that uses a stop light format, and it has been using data to closely track the health of BOP systems and using those reports to reduce drilling time lost due to equipment problems.

Since 2012, BP’s program to identify and address the causes of BOP-related downtime allowed it to reduce the number of drilling days when equipment was pulled for repairs from 600 days in 2012 to 150 days in 2015, said David Eytton, group head of technology for BP.

“Now we know if it is not 100 percent, that brings a lot of pressure to bear on the manufacturer” to resolve costly problems, he said.

Jose Gutierrez, director, Technology and Innovation for Transocean, said the results of sophisticated mathematical analysis must be grounded in an understanding of how machines perform while drilling.

“What we need to measure are those right moments and right values,” he said. The data can be used to track the likely
life span of parts using established methods. “That is not analytics. It is common engineering logic.”

NOV uses a stream of data from BP and others to build more reliable products. The company has a team of data scientists working closely with its engineering experts to study product performance. Their priorities are based on a list ranking the problems based on how much they cost users.

One of their projects is a database gathering all of the data related to each of its elastomer products from the day these critical rubber parts are made at the NOV plant. It will also include product testing results and how each part performs over its lifetime.

BOP makers are also working on better software to detect early signs of possible problems while drilling. “The [BOP] function logger is morphing into an onboard diagnostic system,” said Lance Staudacher, electrical controls manager for NOV Rig Systems.

The early results have been encouraging. “The improvement that has happened. It is pretty remarkable,” said Frank Springett, vice president and general manager for the pressure control group at NOV. “What we see as the next step is gaining the ability to predict failures before they happen and act accordingly.”

**Maintenance by the Numbers**

BOP maintenance schedules are normally based on the time the BOP has been in service. The BSEE well control rule requires owners to “break down the entire BOP system every 5 years for recertification.” These inspections, which can be done in stages, require each part to be inspected and worn ones replaced.

Equipment makers point out that there is little evidence supporting the need for this costly system, and that taking a complex machine apart and putting it back together can cause problems.

“There is nothing behind the 5 years (schedule) except that it is an industry accepted rule of thumb,” Judge said. GE and others are working to change that by building a case for standards based on how fast parts actually wear out. The companies are creating software that counts cycles on their equipment—the number of times each component is used. The goal is a dependable estimate of how many cycles their parts are likely to last, under specific conditions. This could allow warnings when a part is nearing the number of cycles where failure is likely so it can be replaced during scheduled downtime.

Other data points are being considered. NOV is tracking the gallons of fluid flowing through valves to see if that is a good wear indicator.

Another regulation in question is the requirement that users test BOPs every 14 days, which is based on an API standard. The test requires drilling to stop so the rams can be closed, adding wear on the equipment. Other methods may make it possible to tell if the equipment is ready to go without having to close the rams.

“That (data analysis) might indicate more confidence in the capability of that equipment,” Morris said. “It might reduce the need to stop drilling activity and do pressure testing as the primary way to determine the health of the equipment.”

Another possibility is using data-based methods to demonstrate that key equipment complies with regulations, reducing the number of offshore inspections, “which are highly disruptive events for operators,” van Oort said.

This does not mean the end of offshore inspections. Those writing and commenting on monitoring say that inspectors will need to see how things are done offshore, but more data could help focus their attention to critical spots in these complex operations.

But rapid change is not likely. NOV got started early on monitoring, with a couple years of data from Ensco Rigs, and the number of rigs it monitors is growing. One thing the company has learned is that BOPs generally do not lead eventful lives. “You do not have failures every day, so it takes years,” Staudacher said.

The pressure readings by a data scientist often require a close look at the hardware to see if an observation is an indication of something that will cause trouble, or just bad data. An early analysis from a GE analytical pilot program showed multiple issues in the electrical system on one BOP stack, but none on its twin. The odds of that happening randomly are impossibly high, Judge said. To figure out why, an engineer...
with expertise in subsea electrical systems was assigned to figure it out.

“What we found is we need to have a subject matter expert alongside a data scientist and let them ask questions,” he said.

An early target for NOV’s team of scientists and engineers was pressure regulators. The device, which manages the pressure of the hydraulic fluid as it goes from the supply line to the BOP, was at the top of its list of costly problems for owners of BOP stacks.

The project began with a course on how regulators work for the data scientists, who also “took them apart to see how we designed them,” Staudacher said. They needed to understand the inner workings of the machines to sift through years’ worth of data and distinguish telling details from bad data.

The result was two algorithms based on data patterns that can indicate potential future trouble. One was based on data showing a change in the normal pattern of pressure changes at one valve. The team observed that the variations appeared to be correlated with changes down the line that could be an indication of a failure ahead.

The data scientists and engineering experts worked together to gather physical evidence that showed that the pressure change could be predictive. Now when a change in the pattern is observed, a note is sent to engineers who decide whether to pass the advisory on to clients, who may or may not act.

“The algorithm is relatively new. We have fairly high confidence. We need to build confidence in customers, who may decide to let it run its course,” Staudacher said.

**Motivating Change**

The value of data-driven drilling ideas depends on the willingness of people and organizations to do what it takes to apply them.

“Remember, getting data and building nice displays and nice visualization programs is the easy part,” said van Oort. “I can show you nice plots analyzing drilling data, and how many days of rig time you can save. That would mean nothing to you unless you had a workflow process, and you have the people that can make the changes in the field instigated by the data analysis.”

A study by NOV analyzing why some parts fail early concluded that “there is a percentage of (failures due to) manufacturing defects, but more are due to installation issues,” Staudacher said.

The next step is understanding what happens during installation, and finding a cost-effective way to change that. One option under consideration is creating training videos on the information page for each component.

Changing habits is hard, but the pay-off for doing so can be large. For example, by analyzing data generated while installing casing, BP created software to track casing runs that it said has eliminated instances of stuck casing, saving more than USD 200 million in the 2-year period ending in mid-2015, said Ahmed Hashmi, global head of upstream technology for BP.

BSEE’s rule requires all companies drilling wells in deep water or in high-pressure/high-temperature formations to have a plan for doing real-time monitoring that supports those operations. It specifies what must be transmitted onshore—data from the BOP control system, drilling fluid flow rates, and drilling data from the bottomhole assembly—and BSEE must be given access upon request.

The regulation said real-time monitoring is to be used “to assist rig personnel in identifying and evaluating abnormalities and unusual conditions before they become critical issues.” But it is up to the companies to figure out how they can best do so. The possibilities include creating a monitoring system connecting experts at various locations, rather than building a center.

One approach that is not likely to work is trying to manage drilling remotely. Drillers do not want someone onshore following along with a computer screen telling them what to do, Carter said.

“Those in a real-time center … are not there to drill the well, but to help the drillers drill the well more efficiently and safely,” he said. Those in the drilling chairs are looking at increasingly crowded displays as more drilling data are added, and can benefit from skilled onshore advisers filling in the gaps.

“The great thing in this is they can provide context over time for a trend.”
Rethinking the Blowout Preventer

BOP Technologies has designed a blowout preventer (BOP) that it says is simpler, more efficient, and, most importantly, can deliver enough power to shear anything that goes into a well.

After 3 years of work, the small Houston company is showing off models and pictures of a new compact, cylindrical design that it says can drive a shearing ram with 5 million pounds of force—more than 60% greater than what is now available—and that will be able to cut through drill collars that cannot be cut by currently available BOPs.

“It delivers the power. That is where they come up short,” said Jay Read, the inventor of the device and founder of BOP Technologies.

The big problem now facing BOP Technologies is “we have got to prove it,” Read said. The company needs to raise millions of dollars to build a BOP big enough to show what it can do to actual steel tubing. But based on his long experience building BOPs for the biggest makers in the industry, he said he is looking forward to it, adding, “I can’t wait.”

While BOP Technologies is talking about its ideas as it seeks backers, Shell and Transocean have quietly been working over the past 3 years on a new-generation BOP control system, said Jose Gutierrez, director, technology and innovation for Transocean.

“This is an opportunity to attack the status quo,” said Gutierrez, adding that the control systems available now are unreliable, resulting in much lost time during drilling. “It removes value from the system,” he said.

The process used by Shell and Transocean relies on methods regularly employed by industries such as aerospace to develop reliability-centered designs, which allow systems to continue working even when parts fail, Gutierrez said, but said he could not provide further details.

In the wake of the blowout of the Macondo field in 2010, which destroyed Transocean’s Deepwater Horizon rig, regulators have focused on reliability and pushed for a BOP able to shear whatever was inside it.

While that remains a goal of the US Bureau of Safety and Environmental
Enforcement (BSEE), which is tracking efforts like BOP Technologies, the offshore regulator has not set a deadline to reach that goal. In BSEE’s recently released well control rule, it calls for BOP stacks with two shear rams to ensure that if one cannot sever what is inside, the other will be able to do so.

In the rule-writing process, a time limit was considered for development of a BOP that can sever anything, but it is not in the final rule because such equipment “probably doesn’t exist” now, though BSEE is still seeking a practical way to reach that goal, said Doug Morris, chief for the office of offshore regulatory programs for BSEE.

Adding to the difficulty for equipment makers is a market where demand for well control equipment has disappeared with the deep slump in offshore exploration and production.

While Gutierrez acknowledged that in this market, “you see blood on the floor,” he is hopeful because there is also “more focus on inventiveness, efficiency, and cost.”

Mark Alley, chief executive officer of BOP Technologies, said “there is serious interest in” his BOP design but he has yet to secure project financing.

The thinking behind the BOP Technologies design began after Read left Cameron and was working at a small think tank considering inventive oilfield ideas. He said that being away from an established BOP maker for the first time in his career freed him from the limits that come with designing products for a company with a successful product where fundamentally changing things has significant consequences.

“We went in it with a different approach to create the ultimate shearing BOP,” he said. One obvious difference is that the device does not have long arms holding the pistons driving the shearing rams. Instead it uses an “intensifier piston.” Pressurized hydraulic fluid fills a larger piston that pushes up, shrinking the area inside the smaller intensifier piston. The compression of the fluid in the intensifier piston turns the 4,000-psi stream of fluid flowing into the larger piston to generate 40,000 psi.

The round shape of the intensifier assembly is reflected in the BOP brand name, Cirbop, which was based on the description: circular intensifier ram blowout preventer. When the BOP is fired, that pressure can be used to drive the rams, applying millions of pounds of force without arms the size of oil drums.

This approach requires a hydraulic supply line operating at 4,000 psi, compared with 7,500 psi for other high-capacity deepwater BOPs, reducing the pressure on the line as well as the pressurized fluid stored in accumulator bottles at the wellsite. It also has about a third fewer parts than a conventional design.

Another difference in the design is the lack of nuts and bolts in sight. This makes it easier to service, Read said, and those connectors are not exposed to salt water.

The case for doing something different is persuasive until one considers the obstacles facing a tiny startup competing with the biggest oilfield service companies at a time when the business is in a deep slump. But Read is optimistic, saying, “I have no doubt in my mind that this will eventually be used. When it will is a big question.”

The expanding piston can magnify the pressure in the intensifier 10-fold, which is used to drive the piston. Illustration courtesy of BOP Technologies.