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BP and the Deepwater Horizon Disaster of 2010

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When he woke up on Tuesday, April 20, 2010, Mike Williams already knew the standard procedure for jumping from a 33,000 ton oil rig: "Reach your hand around your life jacket, grab your ear, take one step off, look straight ahead, and fall."[1] This would prove to be important knowledge later that night when an emergency announcement was issued over the rig's PA system.

Williams was the chief electronics technician for Transocean, a U.S.-owned, Switzerland-based oil industry support company that specialized in deep water drilling equipment. The company's $560 million Deepwater Horizon rig was in the Gulf of Mexico working on the Macondo well. British Petroleum (BP) held the rights to explore the well and had leased the rig, along with its crew, from Transocean. Of the 126 people aboard the Deepwater Horizon, 79 were from Transocean, seven were from BP, and the rest were from other firms including Anadarko, Halliburton, and M-1 Swaco, a subsidiary of Schlumberger.

Managing electronics on the Deepwater Horizon had inured Williams to emergency alarms. Gas levels had been running high enough to prohibit any "hot" work such as welding or wiring that could cause sparks. Normally, the alarm system would have gone off with gas levels as high as they were. However, the alarms had been disabled in order to prevent false alarms from waking people in the middle of the night. But the emergency announcement that came over the PA system on the night of April 20 was clearly no false alarm.

[1] Testimony from Michael Williams, The Joint United States Coast Guard/The Bureau of Ocean Energy Management, "FUSCG/BOEM Marine Board of Investigation into the marine casualty, explosion, fire, pollution, and sinking of mobile offshore drilling unit deepwater horizon, with loss of life in the Gulf of Mexico 21-22 April 2010," Transcript, July 23, 2010, pp. 24-25.

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Moments after the announcement, Williams was jolted by a nearby thud and a hissing sound, followed by the revving of one of the rig's engines. Before he knew it, there were two explosions forcing him and other crew members to abandon ship by jumping into the partially flaming ocean.[2] Of the 126 workers on board the Deepwater Horizon, 17 were injured, including Williams, and 11 were killed. The rig burned for 36 hours, combusting the 700,000 gallons of oil that were on board, leaving a trail of smoke over 30 miles long. The Deepwater Horizon sank on April 22, taking with it the top pipe of the well and parts of the system that were supposed to prevent blowouts from occuring.[3]

As of 2010, the Deepwater Horizon disaster was the largest marine oil spill ever to occur in U.S. waters. By the time the well was capped on July 15, 2010, nearly five million barrels of oil (205.8 million gallons) had spilled into the Gulf of Mexico. Federal science and engineering teams revised their estimates on the rate of oil flow several times, and in August they concluded that between April 20 and July 15, 53,000-62,000 barrels per day spilled into the Gulf,[4] an amount that was equivalent to a spill the size of the 1989 Exxon Valdez every four to five days.[5] Before the Deepwater Horizon disaster, the Exxon Valdez held the record for the largest spill in U.S. waters.

It was surprising to many analysts how such a disaster could happen, particularly involving a company like BP, which publicly prided itself on its commitment to safety. It did seem clear that, in an effort to close up the Macondo well, several key decisions were made, each involving multiple stakeholders and trade-offs of time, money, safety, and risk mitigation. The public debate began immediately on whether the result of these decisions indicated operational or management problems on the rig, and whether these problems were endemic to the oil industry, or resided within BP itself. To help answer these questions, several task forces were formed to investigate the root causes of the disaster and who among the various players involved with the Macondo well bore responsibility for the disaster and for its resolution.

British Petroleum

The company that would become BP was founded in 1909 as the Anglo-Persian Oil Company (APOC) shortly after Englishman William Knox D'Arcy struck oil in Iran after an eight-year search. In its early years, profitability proved elusive for APOC and, in 1914, Winston Churchill, who was head of the British Navy and believed Britain needed a dedicated oil supply, convinced the British government to buy a 51% stake in the nearly bankrupt company.

[2] The Joint United States Coast Guard/The Bureau of Ocean Energy Management, "FUSCG/BOEM Marine Board of Investigation into the marine casualty, explosion, fire, pollution, and sinking of mobile offshore drilling unit deepwater horizon, with loss of life in the Gulf of Mexico 21-22 April 2010," Transcript, July 23, 2010, pp. 10-14.

[3] U.S. House of Representatives Committee on Energy and Commerce, "Chronology of Deepwater Horizon Events," June 15, 2010.

[4] Campbell Robertson and Clifford Kraus, "Gulf Spill is Largest of Its Kind, Scientists Say," *The New York Times*, August 3, 2010.

[5] Calculation based on a spill size of 10.8 million gallons for the *Exxon Valdez*. Justin Gillis and Henry Fountain, "New Estimates Double Rate of Oil Flowing Into Gulf," *The New York Times*, June 10, 2010.

The British government's majority ownership of BP lasted until the late 1970s when the government, under Prime Margaret Thatcher, a proponent of privatization, began selling off its shares in an attempt to increase productivity in the company. When the government sold its final 31% share in 1987, BP's performance was floundering. The company's performance continued to decline as a newly private company; in 1992, BP posted a loss of $811 million. Nearing bankruptcy, the company was forced to take dramatic cost cutting measures.

Things started to improve measurably in the mid-1990s. With a streamlined workforce and portfolio of activities, BP's new CEO began implementing an aggressive growth strategy, highlighted by mergers with rivals Amoco in 1998, and ARCO (the former Atlantic Richfield) in 2000.

Along with focusing on growth, BP began repositioning itself. In 2001, the company launched the new tagline "Beyond Petroleum" and officially changed its name to "BP." The associated green branding campaign indicated that BP wanted to be known as an environmentally-friendly oil company. Over the next decade, the company launched an Alternative Energy division and was, for a time, the world's largest manufacturer of solar cells and Britain's largest producer of wind energy. BP invested $4 billion in alternative energy between 2005 and 2009.[6] BP's total company investment over the same time period was $982 billion.[7]

In May 2007, Tony Hayward, who had been chief executive of Exploration and Production (BPX), replaced John Browne as CEO. Hayward marked his appointment with a speech pledging to "focus like a laser on safety issues, put the brakes on growth and slash production targets."[8] Hayward was able to improve corporate performance, in part, by dramatically shrinking the Alternative Energy division and further reducing headcount at both managerial and lower staff levels.[9] Between 2006 and 2009, BP's workforce fell from 97,000 to 80,300.[10]

In addition to cutting four levels of management, Hayward also spoke publicly about his desire to transform BP's culture to one that was less risk averse. He believed that too many people were making too many decisions leading to extreme cautiousness. "Assurance is killing us," he told U.S. staff in September of 2007.[11]

Despite Hayward's concern about the company's risk averse culture, in a relatively short period of time, BP had transitioned from a small, state-sponsored company to one of the six largest non-state-owned oil companies in the world and, in the month before the Deepwater Horizon disaster, the largest company listed on the London Stock Exchange. The transition required numerous mergers

[6] "BP Sustainability Reporting 2009: Alternative Energy," *BP Publication*, April 15, 2010.
[7] BP annual financial statements: 2007 and 2009.
[8] Tony Hayward, "BP 2008 Strategy Presentation," *BP Publication,* February 27, 2008.
[9] Ibid.
[10] BP.com archive information on employment, for 2006 data; "BP at a Glance" from BP.com, accessed October 10, 2010 for 2009 data.
[11] Graeme Wearden, "BP to Take Axe to Management," *The Guardian*, September 25, 2007.

and acquisitions, and strict cost cutting measures. Along the way, BP's organizational structure was also dramatically transformed.

Organizational Strategy

BP in the late 1980s comprised several layers of management in a matrix structure that made it difficult for anyone to make decisions quickly. In some cases, simple proposal changes required 15 signatures. At the same time, the company was overleveraged and its overall performance was suffering.[12] Robert Horton, who was appointed CEO in 1989, started a radical turnaround program in an effort to cut $750 million from BP's annual expenses. He removed several layers of management and slashed the headcount at headquarters by 80. Horton also intended to increase the speed of managerial decision-making and, thereby, the pace of business in general. Horton transformed hierarchically structured departments into smaller, more flexible teams charged with maintaining open lines of communication.[13]

Horton transferred decision-making authority away from the corporate center to the upstream and downstream business divisions. While deep cuts were made to capital budgets and the workforce, employees at all levels were encouraged to take responsibility and exercise decision-making initiative. In 1992 David Simon was appointed CEO replacing Robert Horton. Simon continued Horton's policy of cost cutting, especially in staffing.

The biggest changes during this period occurred in BPX, which was led by John Browne. Building upon his predecessors' efforts, Browne, who envisioned creating a spirit of entrepreneurship among his staff, extended decision-making responsibilities to employees at more levels in the organization. Under the new strategy, decision-making authority and responsibility for meeting performance targets was no longer held by BP's regional operating companies, but by onsite asset managers.[14] Asset managers contracted with BP to meet certain performance targets and extended this practice among all employees working on a given site. Employee compensation was tied to asset performance and the overall performance of the site. The model, which was known as an "asset federation," was later applied across the company after Browne took over as CEO in 1995.

One tradeoff with the asset federation model was that because each site manager managed their "asset" autonomously and was compensated for its performance, there was little incentive to share best practices on risk management among the various BP exploration sites.[15] There were also downsides to a system in which a centralized body had little oversight over the setting of performance targets, particularly in an industry where risk management and safety were essential to the long-term success of an oil company. And BP had had its shares of safety breaches.

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[12] John Roberts, "Organizing for Performance: How BP Did It," *Stanford Business,* February 2005.

[13] "BP After Horton," *The Economist,* July 4, 1992.

[14] Each physical well site was called an asset and the site managers were "asset managers."

[15] David Apgar, "Time to Break BP Up," *The Globalist*, June 22, 2010.

Safety Issues at BP

In the mid-2000s, disaster struck BP twice within a 12-month period. The first happened on March 23, 2005 when an explosion at BP's Texas City Refinery killed 15 people and injured another 180, and resulted in financial losses exceeding $1.5 billion. BP commissioned James Baker, a former U.S. secretary of state and oil industry lawyer, to write an investigative report on the Texas City tragedy. One of the key findings highlighted in the *Baker Report* was that the company had cut back on maintenance and safety measures at the plant in order to curtail costs, and that responsibility for the explosion ultimately rested with company senior executives.[16]

Another concern outlined in the report was that while BP had emphasized personal safety and achieved significant improvements, the company "has mistakenly interpreted improving personal injury rates as an indication of acceptable process safety, creating a false sense of confidence."[17] The report goes on to state the following:

> The Panel's refinery-level interviews, the process safety culture survey, and some BP documents suggest that significant portions of the U.S. refinery workforce do not believe that process safety is a core value at BP. As many of the refinery interviewees pointed out, and as some BP documents and the process safety culture survey seem to confirm, one of the reasons for this belief is that BP's executive and corporate refining management have not communicated a consistent and meaningful message about the importance of process safety and a firm conviction that process accidents are not acceptable. The inability of many in the workforce to perceive a consistent and meaningful corporate message about process safety is easy to understand given the number of "values" that BP articulates:
>
> - BP's 18 "Group values," only one of which encompasses health and safety—the company's broad, aspirational goal of "no accidents, no harm to people, and no harm to the environment."
> - Four "Brand values," which BP claims, "underpin everything we do": being performance driven, innovative, progressive, and green.
>
> None of these relates to safety.
>
> These messages to the BP workforce on so many values and priorities contribute to a dilution of the effectiveness of any management message on process safety. This is consistent with a recent observation from the organizational expert that BP retained under the 2005 OSHA settlement relating to Texas City: There appears to be no one, over-arching, clearly-stated worksite policy at Texas City, regardless of respondents' answers. The BP stated policy on health and safety, "no

[16] James Baker et al., "The Report of the BP U.S. Refineries Independent Safety Review Panel," January 2007. pp. 82-85.
[17] Ibid, p. 72.

> accidents, no harm to people and no damage to the environment" is not widely known at Texas City and points to a weak connection between BP Texas City and BP as a corporation. Safety communication is viewed more as a function of particular individuals in Texas City versus a BP-wide commitment.
>
> Until BP's management, from the Group Chief Executive down through the refinery superintendents, consistently articulates a clear message on process safety, it will be difficult to persuade the refining workforce that BP is truly committed on a long-term basis to process safety excellence.[18]

In March 2006, as *The Baker Report* was being written, a second disaster struck BP, this time in Alaska's Prudhoe Bay, where more than 200,000 gallons of oil poured into the bay from a corroded hole in the pipeline, making it the largest oil spill in Alaska.[19] Inspectors found that several miles of the steel pipe had corroded to dangerously thin levels. Alaskan state regulators had been warning BP since 2001 that its management procedures were out of alignment with state regulations, and that critical equipment needed to be better maintained.

BP took several actions in response to *The Baker Report* and other reports, including one that was overseen by John Mogford, a senior group vice president of safety for BPX, on its safety. According to Appendix F, a supplement to *The Baker Report*, these actions included:

- **Leadership visibility.** John Browne, BP's group chief executive, met with the company's top 200 leaders to stress BP's commitment to safety and communicate his expectations regarding safety. Members of the new Safety and Operations organization visited BP's U.S. refineries and gave presentations regarding the importance of process safety and the importance of the Mogford Report recommendations. Additionally, BP senior managers have attended town hall meetings with employees to discuss safety issues. The chief executive, Refining and Marketing, conducted meetings for all U.S. refining employees, and the president of BP America conducted meetings and sent written communications to BP America employees regarding safety issues.
- **Review of employee concerns.** BP appointed retired United States District Judge Stanley Sporkin to hear and review BP employee concerns.
- **Auditing.** The Safety and Operations organization is creating an enhanced audit function, including additional audit personnel and a number of external hires. BP has listed audit-finding closure as one element of a six-point plan for sustained development. The new audit group is developing enhanced audit protocols to better assess actual operations against applicable standards.

[18] Ibid, p. 61.

[19] Abrahm Lustgarten and Ryan Knutson, "Reports at BP over Years Find History of Problems," *Washington Post*, June 8, 2010.

- **Resources for plant, equipment, and systems.** BP has announced that it has earmarked $7 billion over the next four years to upgrade all aspects of safety at its U.S. refineries and to repair and replace infield pipelines in Alaska. The company has also announced $300 million in funding and significant external input for process safety management renewal in refining.

Though some of these changes were company-wide, many were specific either to Texas City or the refinery operations within BP.[20] Still, BP executives clearly realized that when it came to safety, there was room for improvement.[21] Between June 2007 and February 2010, 97% (829 of 851) of the willful safety violations by an oil refinery handed down by the Occupational Safety and Health Administration went to two BP-owned refineries in Texas and Ohio.[22]

The Macondo Well Project

The Macondo Prospect was located 52 miles south of the port of Venice, Louisiana in the Gulf of Mexico. At nearly 5,000 feet below sea level, the well demonstrated great potential for extracting oil, but was also somewhat hazardous. Natural gas levels were high in the reservoirs, which made drilling challenging.[23]

Drilling in deep water and ultra-deep water[24] started to become economically profitable and technically feasible on a large scale in the mid-2000s, due to higher world prices for crude oil and improvements in drilling technology. The number of deep water rigs in the Gulf of Mexico increased from just three in 1992 to 36 in 2008.[25] Because of the complexities of deep water operations, creating a productive deep water oil field was extremely expensive compared to shallow water oil drilling. But the potential payoff was enticing. A well producing in shallow water might yield a few thousand barrels of oil a day. By contrast, deep water wells could yield more than 10,000 barrels per day.[26]

BP acquired the rights to the Macondo Prospect from the U.S. Minerals Management Service in March of 2009.[27] As the oil industry regulator, the MMS issued permits to oil companies wanting to drill on U.S. land or in U.S. waters. In exchange, it received royalty revenue from oil companies. BP was the principal developer and operator of the prospect and held a 65% financial share in the project.[28] While BP maintained operational decision-making authority, Transocean employees, who performed the majority of the work on the rig, had some decision-making authority over operations

[20] Baker Report Appendix F – BP post Texas City Measures. p. F-1.

[21] The BP U.S. Refineries Independent Safety Review Panel, 2007.

[22] Pierre Thomas, Lisa A. Jones, Jack Cloherty, and Jason Ryan, "BP's Dismal Safety Record," *ABC World News*, May 27, 2010.

[23] http://www.deepwaterinvestigation.com/external/content/document/3043/856507/1/7-23-10.pdf p. 70.

[24] "Ultra-deep water" is considered water 5000 or more feet below sea level.

[25] Lesley D. Nixon et al, "Deepwater Gulf of Mexico 2009: Interim Report of 2008 Highlights," *OCS Report* (New Orleans: U.S. Department of the Interior Minerals Management Service Gulf of Mexico OCS Region), May 2009.

[26] Fred H. Bartlit, Jr., Chief Counsel, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. Macondo Gulf Oil Disaster Chief Counsel's Report 2011, February 17, 2011.

[27] "Macondo," SUBSEAIQ, (http://www.subseaiq.com/Data/Project.aspx?project_Id=562) accessed October 10, 2010.

[28] BP's financial partners for Macondo were Texas-based Anadarko Petroleum Corporation which owned a 25% share, and MOEX Offshore 2007, a unit of Japan-based Mitsui, which owned a 10% share.

and maintenance. BP started drilling the Macondo well in October of 2009. Drilling, however, was interrupted in the aftermath of Hurricane Ida. BP commenced drilling on February 3, 2010 leasing Transocean's Deepwater Horizon rig.[29]

Transocean charged BP approximately $500,000 per day to lease the rig, plus roughly the same amount in contractor fees.[30] BP originally estimated that drilling the Macondo well would take 51 days and cost approximately $96 million. By April 20, 2010 the rig was already on its 80th day on location and had far exceeded its original budget.[31]

The Deepwater Horizon Rig

The Deepwater Horizon rig came with a long list of maintenance issues. In September 2009, BP conducted a safety audit on the rig, which was in use at another BP drilling site at the time. The audit identified 390 repairs that needed immediate attention and would require more than 3,500 hours of labor to fix.[32] It was later learned that the Deepwater Horizon had not gone to dry-dock for nine years previous to the disaster and never stopped working at any point between the September 2009 audit and April 20, 2010.[33]

As Transocean's Chief Electronics Technician Mike Williams experienced, the crew had to be adept at developing workarounds in order to maintain the function of the rig. Williams was responsible for maintaining the Drilling Chairs — the three oversight computers that controlled the drilling technology. These computers, operating on a mid-1990s era Windows NT operating system, would frequently freeze. If Chair A went down the driller would have to go to Chair B in order to maintain control of the well. If somehow all three chairs went down at once, the drill would be completely out of control.[34] Williams frequently reported the software problems and the need to have them fixed.[35]

Despite the hazards of the Macondo well site, the known maintenance issues on the rig, and the setbacks that had caused the project to be over budget, BP felt confident that it had found oil. However, since the Deepwater Horizon was an exploratory vessel, the crew was under orders to close the well temporarily[36] and return later with another rig to extract the oil.

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[29] "Macondo," SUBSEAIQ, (http://www.subseaiq.com/Data/Project.aspx?project_Id=562) accessed October 10, 2010.

[30] Ben Casselman and Russell Gold, "BP Decisions Set Stage for Disaster," *Wall Street Journal*, May 27, 2010.

[31] BP, *GOM Exploration Wells Me* 252 *#1 - Macondo Prospect Well information* (Sept 2009) (BP-HZN-CEC008714) (http://energycommerce.house.gov/documents/20100614).

[32] Robbie Brown, "After Another Close Call, Transocean Changed the Rules," *The New York Times*, August 16, 2010.

[33] Ibid; Testimony from Michael Williams, The Joint United States Coast Guard/The Bureau of Ocean Energy Management, "FUSCG/BOEM Marine Board of Investigation into the marine casualty, explosion, fire, pollution, and sinking of mobile offshore drilling unit deepwater horizon, with loss of life in the Gulf of Mexico 21-22 April 2010," Transcript, July 23, 2010, p. 153.

[34] Ibid, pp. 42-44.

[35] Ibid, pp. 98-102.

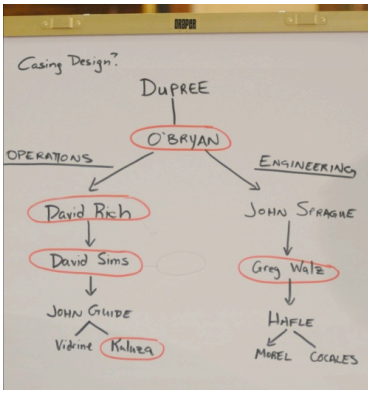
[36] "Temporary abandonment" is the industry term for temporarily closing but not plugging a well.

Anatomy of a Disaster

While the process of closing a well is always complex, closing the Macondo well proved particularly so due to competing interests of cost, time and safety, as well as the number of people and organizations involved in the decision-making process. (See **Exhibit 1**.) As one example, 11 companies[37] played a role in the construction of the casing[38] for the Macondo well, all with different responsibilities for various aspects of setting the well. Halliburton, for instance, was responsible for cement-related decisions, although many of these decisions were contingent on decisions made by BP managers on well design.

Adding to the complexities of decision making on the Deepwater Horizon was the fact that many of BP's decision makers for the Macondo well had only been in their positions for a short time before disaster struck. See **Figure 1.**

Figure 1 Deepwater Horizon Chain of Command



Name	Title	Days/Months in Position
Patrick O'Bryan	VP, Drilling and Completions, Gulf of Mexico	3 months
David Rich	Wells Manager	6 months
David Sims	Drilling Operations Manager	18 days
Robert Kaluza	Well Site Leader	4 days
Greg Walz	Drilling Engineering Team Leader	18 days (took David Sims's previous position)

Note: **Exhibit 2** is a corrected version based on court testimonies that includes full names and titles.

Source: BP as presented at the hearings of the US Coast Guard and the Interior Department's Bureau of Ocean Management, Regulation and Enforcement, August 26, 2010.

As the Deepwater Horizon Disaster was dissected in various public forums, questions arose as to whether, in concert with the chaotic mix of decision makers, three key decisions on closing the Macondo well played a role in the downing of the 33,000 ton oil rig. (U.S. Congressional Representatives Henry Waxman and Bart Stupak called out these decisions in a letter dated June 14, 2010 to BP CEO Tony Hayward just days before his testimony before the Subcommittee on Oversight and Investigations. See **Exhibit 3**.)

[37] BP, Weatherford, Hydril, Allamon, Blackhawk, Halliburton, Schlumberger, Sperry, M-I SWACO, Nexen, and K&B.

[38] Casing is the lining of the drilled well hole. Ensuring a sound casing is essential to preventing any oil or gas leakage and maintaining the well as a resource for future oil production.

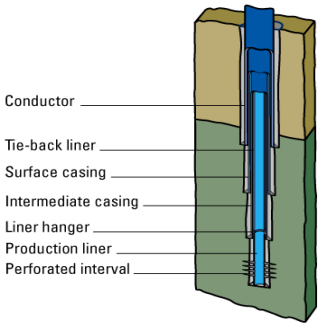
Well Casing

Deep water wells are drilled in sections. The process of deep water drilling involves drilling through rock at the bottom of the ocean, installing and cementing casing to secure the well hole, then drilling deeper and repeating the process. On April 9, 2010, the crew of the Deepwater Horizon finished drilling the last section of the well, which extended 18,360 feet below sea level and 1,192 feet below the casing that had previously been inserted into the well.[39]

During the week of April 12, BP project managers had to decide how best to secure the well's final 1,192-foot section. One option involved hanging a steel tube called a liner from a liner hanger on the bottom of the casing already in the well and then inserting another steel liner tube called a "tieback" on top of the liner hanger. The liner/tieback casing option provided four barriers of protection against gas and oil leaks getting into the well accidentally. These barriers included the cement at the bottom of the well, the hanger seal that attaches the liner to the existing casing in the well, the cement that secures the tieback on top of the liner, and the seal at the wellhead.[40]

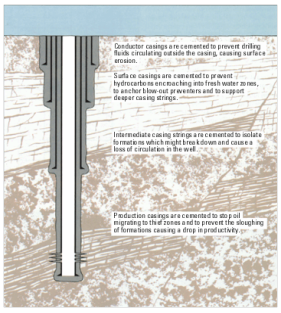
The other casing option, known as "long string casing," involved running a single string of steel casing from the seafloor all the way to the bottom of the well. (Both options are depicted in **Figure 2**.) Long string casing provided two barriers to the flow of gas up the annular space that surrounded the casing: the cement at the bottom of the well and the seal at the wellhead. Compared to the liner tie-back option, the long string casing option took fewer days to install.

Figure 2 Diagram of a Liner



Note: A liner completion incorporates a short casing string, hung off from a predetermined point in the intermediate casing string. This provides several benefits, including reduced material cost and greater flexibility in the selection of completion components in the upper wellbore area.

Diagram of a Casing String



Note: Pipe is run into the wellbore and cemented in place to protect aquifers, to provide pressure integrity and to ensure isolation of producing formations.

Source: Schlumberger.

[39] BP, PowerPoint Presentation, *Washington Briefing, Deepwater Horizon Interim Incident Investigation*, May 24, 2010.

[40] Briefing by Tommy Roth, Vice President of Cementing, Halliburton, to House Committee on Energy and Commerce Staff (June 3, 2010); Halliburton, PowerPoint Presentation, *Energy and Commerce Committee Staff Briefing* (June 3, 2010).

The decision about which casing design to use changed several times during the month of April. A BP *Forward Plan Review* from mid-April 2010 recommended against using long string casing because of the inherent risks of having fewer gas barriers. But internal communications within BP indicated the company was actually leaning towards using the long string casing option. On March 25, 2010, Brian Morel, a BP drilling engineer, emailed Allison Crane, a materials management coordinator for BP, that choosing long string casing "saves a lot of time ... at least 3 days…" On March 30, he emailed Sarah Dobbs, the BP completions engineer, and Mark Hafle, another BP drilling engineer, that "not running the tieback ... saves a good deal of time/money."[41] On April 15, BP estimated that using a liner instead of the long string casing "will add an additional $7 - $10 million to the completion cost."[42]

A few days after BP completed the first version of its *Forward Plan Review*, the company released a revised version which referred to the long string casing option as "the primary option" and the liner as "the contingency option."[43] Like the earlier version of the *Forward Plan Review*, this version acknowledged the risks of long string casing, but considered it the "best economic case and well integrity case for future completion operations."[44]

Centralizers

In closing up the well, BP was responsible for cementing in place the steel pipe that ran into the oil reservoir. The cement would fill the space between the outside of the pipe and surrounding rock, allowing a more uniform cement sheath to form around the pipe, while preventing any gas from flowing up the sides. Centralizers are special brackets that are used to help keep the pipe centered.

To help inform decision-making on the well pipe centralization, BP hired Halliburton, the cementing contractor, to run technical model simulations and cement lab tests. Jesse Marc Gagliano was the Halliburton account representative for BP. He worked in BP's Houston office and was on the same floor as the BP Macondo well management team of John Guide, who was part of the operations unit, and Brett Cocales, Brian Morel, and Mark Hafle who were part of the engineering unit.[45] Gagliano also worked with the Halliburton crew members on the rig to advise them on logistics and ordering products.

One of Gagliano's chief responsibilities was running the OptiCem model, a multi-factor simulation designed to help predict potential gas flow that might interfere with getting a good cement job on a well site. The OptiCem model, considered highly reliable, took data inputs from BP engineers and

[41] http://energycommerce.house.gov/documents/20100614/BP-March30.Email-string.costs.less.than.tieback.pdf.

[42] BP, *Drilling & Completion MOC Initiate* (Apr. 15, 2010) (BP-HZN-CEC021656).

[43] http://energycommerce.house.gov/documents/20100614/BP-Production.Casing.TA.Options-String.Again.Best.Option.pdf.

[44] Ibid.

[45] http://www.deepwaterinvestigation.com/external/content/document/3043/903579/1/USCGHEARING%2024_Aug_10.pdf Ibid; Testimony from Jesse Marc Gagliano, The Joint United States Coast Guard/The Bureau of Ocean Energy Management, "FUSCG/BOEM Marine Board of Investigation into the marine casualty, explosion, fire, pollution, and sinking of mobile offshore drilling unit deepwater horizon, with loss of life in the Gulf of Mexico 21-22 April 2010," Transcript, August 24, 2010, p. 242.

evaluated the likely effectiveness of various well designs. As he explained in his testimony before The Joint United States Coast Guard/Bureau of Ocean Energy Management, Regulation and Enforcement hearing, "It is a model. It is as good as the information you put into it. So the more accurate information you have, the more accurate the output will be."[46] After running the model, Gagliano discovered that if BP used only six centralizers, as was planned, the risk for gas flow problems was quite significant. He found that at least 21 centralizers would be needed to significantly lower the risk.[47]

Though nothing was written down, court testimony revealed that on April 15, Gagliano had discussed the modeling results with Morel, Hafle, Cocales, and Greg Walz, BP's drilling engineering team leader, in their Houston office. During their discussion, Gagliano expressed concern that the OptiCem results indicated a very high risk that the cement job would encounter "channeling."[48] BP's Morel, however, questioned the reliability of the results because some of the earlier outputs related to compression factors in the well were different than what the crew engineers measured onsite.[49] According to Gagliano, the group spent much of the morning trying to figure out the best way to use the centralizers they did have. After their meeting, a series of emails were exchanged, leading off with one from Morel at 4:00pm on Thursday, April 15.

From: Morel, Brian P [redacted]
Sent: Thursday, April 15, 2010 4:00 PM
To: Jesse Gagliano; Hafle, Mark E; Cocales, Brett W; Walz, Gregory S
Subject: RE: OptiCem Report
Attachments: image002.jpg; image003.jpg

We have 6 centralizers, we can run them in a row, spread out, or any combinations of the two. It's a vertical hole so hopefully the pipe stays centralized due to gravity. As far as changes, it's too late to get any more product to the rig, our only options is to rearrange placement of these centralizers. Please see attached diagram for my recommendation.

A few hours after Morel sent his email, Walz wrote a lengthy email to Guide, the Macondo well operations manager, expressing his concern about using just six centralizers.

[46] Ibid. p. 273.

[47] Ibid, p. 296.

[48] Channeling occurs when you do not get a full circulation of cement to displace the drilling mud. Some of the mud will be left behind. In any place where there is mud left in place, it will prevent a proper cement bond. This problem would appear in a cement bond log. To solve the problem, a tool is sent down the well pipe to puncture the pipe and insert additional cement.

[49] http://www.deepwaterinvestigation.com/external/content/document/3043/903579/1/USCGHEARING%2024_Aug_10.pdf; Testimony from Jesse Marc Gagliano, The Joint United States Coast Guard/The Bureau of Ocean Energy Management, "FUSCG/BOEM Marine Board of Investigation into the marine casualty, explosion, fire, pollution, and sinking of mobile offshore drilling unit deepwater horizon, with loss of life in the Gulf of Mexico 21-22 April 2010," Transcript, August 24, 2010 p. 296.

From: Walz, Gregory S
To: Guide, John
Sent: Fri Apr 16 00:50:27 2010
Subject: Additional Centralizers

John,
Halliburton came back to us this afternoon with additional modeling after they loaded the final directional surveys, caliper log information, and the planned 6 centralizers. What it showed, is that the ECD at the base of sand jumped up to 15.06 ppg . This is being driven by channeling of the cement higher than the planned TOC.
We have located 15 Weatherford centralizers with stop collars (Thunder Horse design) in Houston and worked things out with the rig to be able to fly them out in the morning. My understanding is that there is no incremental cost with the flight because they are combining the planned flights they already had. The maximum they could fly is 15.
The model runs for 20 centralizers (6 on hand + 14 new ones) reduce the ECD to 14.65 ppg, which is back below the 14.7+ ECD we had when we lost circulation earlier.
There has been a lot of discussion about this and there are differing opinions on the model accuracy. However, the issue, is that we need to honor the modeling to be consistent with our previous decisions to go with the long string. Brett and I tried to reach you twice to discuss things. David was still here in the office and I discussed this with him and he agreed that we needed to be consistent with honoring the model.
To be able to have this option we needed to kick things off at 6:00 pm tonight, so I went ahead and gave Brett the go ahead. We also lined up a Weatherford hand for installing them to go out on the same flight. I wanted to make sure that we did not have a repeat of the last Atlantis job with questionable centralizers going into the hole.
John, I do not like or want to disrupt your operations and I am a full believer that the rig needs only one Team Leader. I know the planning has been lagging behind the operations and I have to turn that around. I apologize if I have over step my bounds.
I would like to discuss how we want to handle these type of issues in the future.
Please call me tonight if you want to discuss this in more detail.

Gregg
Drilling Engineering Team Leader
GoM Drilling & Completions
Office: [redacted]
Cell:
E-Mail: [redacted]

Guide responded to Walz's email early in the afternoon on Friday, April 16, expressing concern about the decision made by his supervisor, David Sims, to order additional centralizers.

From: Guide, John
To: Walz, Gregory S
Sent: Fri Apr 16 12:48:11 2010
Subject: Re: Additional Centralizers
I just found out the stop collars are not part of the centralizer as you stated. Also it will take 10 hrs to install them. We are adding 45 pieces that can come off as a last minute addition. I do not like this and as David approved in my absence I did not question but now I very concerned about using them

From: Walz, Gregory S
Sent: Friday, April 16, 2010 12:53 PM
To: Guide, John
Subject: Re: Additional Centralizers

I agree. This is not what I was envisioning. I will call you directly.

Gregg Walz
[redacted]
Sent from my BlackBerry

When asked in court why he would ever question the OptiCem model's results, Guide responded, "There were several reasons, first of all, it's a model, it's a simulation, it's not…the real thing. From past experiences sometimes it's right and sometimes it's wrong. And I also know in this particular case…they made reference to having to tinker with it to try to get some of the results that were reasonable."[50]

Meanwhile, Morel had gotten 3D profile information on the well hole, which indicated that it was actually very straight: 6/10ths of a degree off of vertical. In an email to Cocales, Morel questioned Gagliano's recommendation to use more centralizers. He believed doing so could slow down the process of sealing and cementing the well.[51]

From: Morel, Brian P
Sent: Friday, April 16, 2010 4:04 PM
To: Cocales, Brett W
Subject: FW: Macondo STK geodetic
This is why I don't understand Jesse's centralizer requirements. You can see from the plot we aren't moving much in terms of footage over long intervals.

Brian

Based on the information about the straightness of the well hole, Cocales believed that despite the OptiCem model's results, additional centralizers would only add a small additional measure of safety.[52] In his reply to Morel, Cocales indicated he was in agreement with Guide.

From: Cocales, Brett W
Sent: Friday, April 16, 2010 4:15 PM
To: Morel, Brian P
Subject: RE: Macondo STK geodetic

Even if the hole is perfectly straight, a straight piece of pipe even in tension will not seek the perfect center of the hole unless it has something to centralize it.

But, who cares, it's done, end of story, will probably be fine and we'll get a good cement job. I would rather have to squeeze than get stuck above the WH. So Guide is right on the risk/reward equation.

Best Regards,
Brett

As it turned out, the additional centralizers that Sims gave the green light to order were a "slip-on" variety that took more time to install on a pipe, and were considered risky because of fears they might come off during installation and get stuck in the casing above the well-head.[53] As a result, Guide and

[50] http://www.deepwaterinvestigation.com/external/content/document/3043/856503/1/7-22-10.pdf, p. 69.
[51] http://www.deepwaterinvestigation.com/external/content/document/3043/903599/1/USCGHEARING%2027_Aug_10.pdf, p. 27.
[52] Ibid, pp. 27, 249-250.
[53] Ibid, p. 191.

Walz decided not to use any additional centralizers. Gagliano later learned of their decision from another Halliburton employee who was on board the Deepwater Horizon.[54] In his witness testimony to The Joint United States Coast Guard/Bureau of Ocean Energy Management, Regulation and Enforcement hearing in July 2010, Guide revealed that no one had considered postponing or putting a stop work order on the cement job until centralizers of the right kind were located.[55]

On April 18, two days after Guide and Walz decided not to use the additional centralizers, Gagliano sent the formal report of the OptiCem results as an email attachment to the Macondo well management team. Page 18 of the report included the following observation: "Gas Flow Potential, 10.29 at Reservoir Zone Measured Depth, 18200.0. Based on the well analysis of the above outlined well conditions, this well is considered to have a SEVERE gas flow problem. Wells in this category fall into Flow Category 3."[56] However, the text of the email that Gagliano sent to the BP managers on April 18 did not say anything about the hazards of the Macondo well. Cocales and Guide later testified that neither had read page 18 – both had merely skimmed the report for the information they were most interested in.[57]

Circulating Mud and the Cement Bond Log

The whole process of cementing an oil well is notoriously tricky. A 2007 study by the MMS found that cementing was the single most significant factor in 18 of 39 well blowouts in the Gulf of Mexico over a 14-year period.[58]

Before cementing a well, it is common industry practice to circulate the drilling mud through the well, bringing the mud at the bottom all the way up to the drilling rig. This procedure, known as "bottoms up," allows workers to check the mud to see if it is absorbing gas leaking in. If so, the gas has to be separated out before the mud can be re-submerged into the well. According to the American Petroleum Institute, it is cementing best practice to circulate the mud at least once.[59] In the case of the Macondo well, BP estimated that circulating all the mud at 18,360 feet would take anywhere from six to 12 hours. According to the drilling logs from Monday, April 19, mud circulation was completed in just 30 minutes.[60]

In concert with the decision to do a partial circulation, BP managers chose not to run a test called a "cement bond log" to check the integrity of the cement job after it was pumped into the well, despite Gagliano's warnings of potential channeling. Workers from Schlumberger had been hired to perform a cement bond log if needed,[61] but on the morning of Tuesday, April 20, about 12 hours before the

[54] http://www.deepwaterinvestigation.com/external/content/document/3043/903579/1/USCGHEARING%2024_Aug_10.pdf, p. 333.
[55] http://www.deepwaterinvestigation.com/external/content/document/3043/856503/1/7-22-10.pdf, p. 363.
[56] http://www.deepwaterinvestigation.com/external/content/document/3043/903599/1/USCGHEARING%2027_Aug_10.pdf, p. 23.
[57] Ibid; http://www.deepwaterinvestigation.com/external/content/document/3043/856503/1/7-22-10.pdf, p. 271.
[58] Chris Morrison, "Gulf Oil Spill: Who's to Blame? BP, Halliburton and the Feds are All Implicated," *CBS Interactive Business Network,* May 3, 2010.
[59] Ben Casselman and Russell Gold, "BP Decisions Set Stage for Disaster," *Wall Street Journal*, May 27, 2010.
[60] http://energycommerce.house.gov/documents/20100614/BP-Daily.Operations.Report.4.18.10.pdf.
[61] http://energycommerce.house.gov/documents/20100614/Schlumberger.MC.252.Timeline.pdf.

blowout, BP told the Schlumberger workers their services would not be needed.[62] According to Schlumberger's contract, BP would pay a cancellation fee equal to 7% of the cost of having the cement bond log and mechanical plug services completed. See **Figure 3**.

Figure 3 Costs and Cancellation Costs for Schlumberger's Services

Equipment and Labor	Estimated Cost if Performed	Actual Cost upon Cancellation
Cement bond log	$128,258.77	$10,165.43
Mechanical plug	$53,075.06	$1,870.01

Source:http://energycommerce.house.gov/documents/20100614/Schlumberger-Cost.of.Completing.Cement.Bond.Log.v.Canceled.Contingency.pdf

BP and the engineers on site had used a decision tree, a system of diagnostic questions to define future actions, to determine whether they would need to perform a cement bond log. (See **Exhibit 4**.) BP ultimately followed their own decision tree accurately, but when reviewed in court, it was pointed out that there could have been channeling in the well pipe during the cement job. Channeling was considered highly likely given that far fewer centralizers were used than what the OptiCem model had recommended. Such mud-cement channeling would not have been picked up in the diagnostic tests listed in BP's decision tree.[63] In fact, the only way to accurately diagnose a bond failure due to channeling was with a cement bond log.[64] However, when asked in court about the decision not to run a cement bond log despite seeing a loss return of 3,000 barrels of drilling mud,[65] Mark Hafle, one of BP's drilling engineers, responded that the model he had from Halliburton indicated that the cement job should be fine.[66] He also went on to explain that a cement bond log would be done *at some point* on this well, but that it was usually done pre-production:

> So, that cement bond log is an evaluation tool that is not always 100% right. There's many factors that can affect its quality. It's not a quantitative tool. It does not tell you the exact percentage of cement at any given point. … It's a tool in the engineering tool box that has to be used with a bit of caution. But if it shows there's no cement two or three years from now when we come to do the completion we will do a remedial cement job on that casing.[67]

Fallout from the Disaster

The impact of the Deepwater Horizon explosion and the subsequent Macondo well oil leak was devastating on a number of fronts, the most obvious being the death of 11 crew members and the injuries sustained by another 17.

[62] Ibid.

[63] http://www.deepwaterinvestigation.com/external/content/document/3043/903579/1/USCGHEARING%2024_Aug_10.pdf, p. 270.

[64] Ibid, p. 271.

[65] A "loss return" happens when the amount of spacer fluid (drilling mud in this case) expected to be displaced by the well cement is not returned to the rig, indicating a leak somewhere in the well hole system.

[66] Mark Hafle's testimony before the Coast Guard Joint Commission, May 28, 2010, p. 46.

[67] Ibid, p. 96.

The environmental damage from the oil spill was extensive, with 25 national wildlife refuges in its path.[68] Oil was found on the shores of all five Gulf States,[69] and was responsible for the death of many birds, fish, and reptiles. The total amount of impacted shoreline in Louisiana alone grew from 287 miles in July to 320 miles in late November 2010.[70] Unlike conditions with the Alaskan Exxon-Valdez oil spill, the contaminated Gulf shoreline was not rock but wetland. Grasses and loose soil, a perfect sponge for holding oil, dominated wetland ecosystems. The spill also occurred during breeding season for pelicans, shrimp, and alligators, and most other Gulf coast species. Ecologists anticipated that entire generations of these animals could be lost if they were contaminated with oil.[71]

In terms of direct economic damages, the sinking of the Deepwater Horizon rig represented a $560 million loss for Transocean and Lloyds of London, the insurance company which had unwritten the rig.[72] The unprecedented loss of an entire semi-submersible rig was predicted to change underwriting policies for all oil rigs. As one underwriter noted, "It's never happened that a semi could burn into the sea and completely sink. Now underwriters have to include that as a risk. That's probably $10,000 to $15,000 more *per day* in rig insurance. They'll make it up by charging more on a per-rig basis."[73]

BP's price tag for the lost oil — five million barrels at the average market crude oil price (for April 20, 2010 through July 15, 2010) of $74.81 per barrel[74]— was $374 million. In addition, if a federal court ruled that the company was grossly negligent, BP could face up to $3.5 billion in fines, or $4,300 per spilled barrel.[75] Of course the company's losses didn't end there. On April 15, five days before the disaster, BP's stock was trading on the NYSE at $60.57 and on June 25, it hit a 14-year low of $27.02.[76] In addition to the frustration felt by shareholders and the public at large that the company had failed at several attempts to stop the leak, they were also unimpressed with BP's PR strategy, citing skepticism over the company's offer to pay fishermen if they signed a waiver promising not to sue the company.[77]

Alongside those companies directly involved with the Macondo well project, the Deepwater Horizon disaster affected the oil industry as a whole. On May 28, 2010, Secretary of the Interior Ken Salazar issued a moratorium on all deep water oil drilling in U.S. waters.[78] The purpose of the moratorium was to allow time to assess the safety standards that should be required for drilling, and to create

[68] Standard and Poor's Industry Surveys: Oil & Gas, Production and Marketing. August, 2010.

[69] Juan A. Lozano, "Tar Balls in Texas Mean Oil Hits All 5 Gulf States," *The Associated Press*, July 6, 2010.

[70] Bowermaster, Jon, "Measuring the extent of oil spillage," Gadling, November 29, 2010.

[71] David A. Fahrenthold and Juliet Eilperin, "Scientists Watch for Environmental Effects of Gulf of Mexico Oil Spill," *Washington Post*, May 1, 2010.

[72] "Chilean Earthquake and Deepwater Horizon," *Lloyds Press Release*, May 26, 2010.

[73] Ford Gunter, "An Explosive Situation," *Porfolio.com*, April 28, 2010.

[74] Calculated based on data from U.S. Energy Information Administration, "Petroleum Navigator," (http://www.eia.doe.gov/dnav/pet/) accessed October 10, 2010.

[75] Joshua Schneyer, "Special Report: Civil Fine in Gulf Spill could be $4,300 barrel," *Reuters,* May 26, 2010.

[76] http://www.google.com/finance?q=NYSE:BP note that these are stock prices on the NYSE. LSE values were different, but followed a similar trend.

[77] Anne C. Mulkern, "BP's PR Blunders Mirror Exxon's, Appear Destined for Record Book," *New York Times,* June 2010.

[78] Jonathan Tilove, "Deepwater Drilling Moratorium Report Delivered to Interior Secretary," *Nola.com,* October 1, 2010.

strategies for dealing with wild wells[79] in deep water. Government analysts estimated that about 2,000 rig worker jobs were lost during the moratorium and that total spending by drilling operators fell by $1.8 billion. The reduction in spending led to a decline in employment—estimates indicated a temporary loss of 8,000 to 12,000 jobs in the Gulf Coast[80]—and income for the companies and individuals that supplied the drilling industry. The moratorium also reduced U.S. oil production by about 31,000 barrels per day in the fourth quarter of 2010 and by roughly 82,000 barrels per day in 2011. This loss, however, was not large relative to total world production, and was not expected to have a discernable effect on the price of oil.[81] The moratorium, originally intended to last until the end of November, was lifted in mid-October 2010.[82]

The economic losses also extended to the thousands of coastal small business owners including fishermen, shrimpers, oystermen, and those whose livelihood depended in whole or in part on fishing or tourism. The tourism industries in Alabama, Louisiana, and Florida were particularly hard hit. Ironically, analysts had previously predicted that tourism in the Gulf region, which was devastated by Hurricane Katrina in 2005, would return to pre-Katrina levels in 2010.[83] Between the energy, fishing, shrimping, and tourism industries, the Gulf region lost an estimated 250,000 jobs in 2010.[84]

In anticipation of the economic aftershocks that would be felt from the oil spill, BP pledged to compensate those individuals whose livelihoods would be affected. On June 16, 2010, in agreement with the U.S. government, the company established the Gulf Coast Claims Facility (GCCF), an escrow fund of $20 billion to pay for the various costs arising from the oil spill. GCCF staff evaluated the claims of companies and individuals who suffered demonstrable damages from the oil spill. The fund was also intended to pay municipalities, counties, and state organizations for lost tax revenue or additional clean-up costs.[85] Kenneth Feinberg, who led the September 11 Victim Compensation Fund, was appointed to oversee the GCCF.

By February 28, 2011, the GCFF had received over 500,000 claims, and 170,000 people and businesses had been paid over $3.6 billion. Some people accused the facility of not acting quickly enough to process claims and make payments. In response, the GCCF increased transparency of the system and hired staff in the Gulf to answer questions from applicants in person.[86] The GCCF was scheduled to remain in place until August 2013.[87]

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[79] A wild well was a well that had blown out of control and was leaking gas, water or oil.

[80] "Estimating the Economic Effects of the Deepwater Drilling Moratorium on the Gulf Coast Economy," *Economics and Statistics Administration of the United States Department of Commerce*, September 16, 2010.

[81] Ibid.

[82] Mark Guarino, "Deep-water Drilling Moratorium Lifted: why neither side is happy," *Christian Science Monitor,* October 12, 2010.

[83] Charisse Jones and Rick Jervis, "Oil Spill Takes Toll on Tourism on Gulf Coast," *USA Today*, June 25, 2010.

[84] Standard and Poor's Industry Surveys: Oil & Gas, Production and Marketing, August, 2010.

[85] Rig workers who lost their jobs as a result of the government moratorium on deep water drilling were not covered by the $20 billion fund. These workers were compensated by a separate $100 million fund.

[86] Kenneth Feinberg, "Update on the BP claims compensation process resulting from the Gulf of Mexico oil spill," *Foreign Press Center, Washington, D.C.,* February 28, 2011.

[87] Ibid.

Conclusion

As of early 2011, investigations into the actual causes of the Deepwater Horizon disaster were ongoing, and the various parties involved in the Macondo well project were engaged in a highly publicized finger pointing exercise. The three major decisions on closing the Macondo well involving the well casing, the number of centralizers used, and the decision not to perform a cement bond log *may* have contributed to the conditions that caused the well to blow out.

Regardless of what the ultimate causes are found to be, the conditions on the Deepwater Horizon, and the culture and organizational architecture of BP and its relationships with its contractors is worth examining. Each of the three decisions discussed above, as well as decisions on how to convey dangerous model results and earlier decisions about how best to structure incentive systems, may have played a role in the outcome. Throughout the decision making process, we see some actors who were advocates of caution over cost, for fixing problems even when inconvenient. Yet court testimony indicates that the three key decisions, and perhaps others as well, came down on the side of cost-reduction and expediency, over caution.

Exhibit 1 Companies Involved with Deepwater Horizon Rig

BP	World's third largest oil company, headquartered in London; project operator with a working interest in the well; hired Transocean's rig to drill the well.
Transocean	World's largest offshore drilling operator, based in Switzerland and Houston; owned an operated the rig.
Cameron	Houston-based manufacturer of oil and gas industry equipment; provided the rig with a blowout preventer -- a devise designed to stop uncontrolled flow of oil or gas -- but the part apparently failed to operate.
Halliburton	Oilfield services company based in Houston and Dubai; provided several services to the rig, including cementing on the well to stabilize its walls.
Hyundai	South Korean company is the world's largest shipbuilder; built the Deepwater Horizon, completed in 2001.
Anadarko	Anadarko, a large, independent, Texas-based petroleum company; has nonoperating interest in the well.

Source: Reuters, Hoovers, the companies as published in Daniel Chang and Jennifer Lebovich's "Gulf Oil Spill Overview," McClatchy Newspapers, May 15, 2010.

Exhibit 2

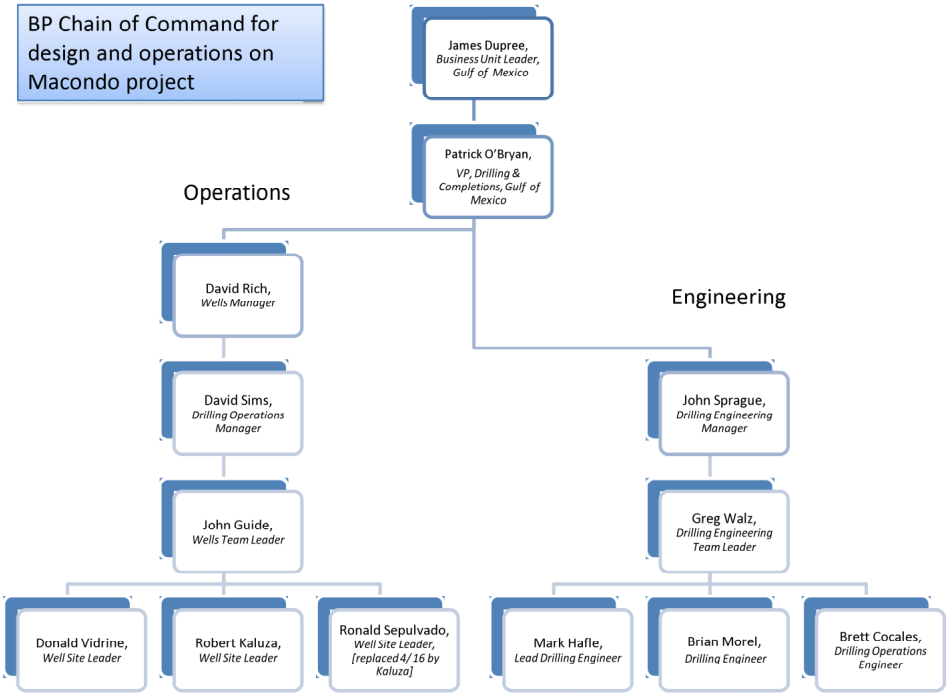


Exhibit 3 Excerpt of Letter to BP CEO Tony Hayward

On June 14, 2010 Chairmen Henry A. Waxman and Bart Stupak sent a letter to Tony Hayward, Chief Executive Officer of BP, prior to his testifying before the Committee, detailing the questions the investigation has raised about BP decisions in the days and hours before the Deepwater Horizon explosion.

Mr. Tony Hayward
Chief Executive Officer
BPPLC
I St. James's Square
London SWI Y 4PD
United Kingdom
June 14, 2010

Dear Mr. Hayward:

We are looking forward to your testimony before the Subcommittee on Oversight and Investigations on Thursday, June 17, 2010, about the causes of the blowout of the Macondo well and the ongoing oil spill disaster in the Gulf of Mexico. As you prepare for this testimony, we want to share with you some of the results of the Committee's investigation and advise you of issues you should be prepared to address.

The Committee's investigation is raising serious questions about the decisions made by BP in the days and hours before the explosion on the Deepwater Horizon. On April 15, five days before the explosion, BP's drilling engineer called Macondo a "nightmare well." In spite of the well's difficulties, BP appears to have made multiple decisions for economic reasons that increased the danger of a catastrophic well failure. In several instances, these decisions appear to violate industry guidelines and were made despite warnings from BP's own personnel and its contractors. In effect, it appears that BP repeatedly chose risky procedures in order to reduce costs and save time and made minimal efforts to contain the added risk.

At the time of the blowout, the Macondo well was significantly behind schedule. This appears to have created pressure to take shortcuts to speed finishing the well. In particular, the Committee is focusing on five crucial decisions made by BP: (I) the decision to use a well design with few barriers to gas flow; (2) the failure to use a sufficient number of "centralizers" to prevent channeling during the cement process; (3) the failure to run a cement bond log to evaluate the effectiveness of the cement job; (4) the failure to circulate potentially gas-bearing drilling muds out of the well; and (5) the failure to secure the wellhead with a lockdown sleeve before allowing pressure on the seal from below. The common feature of these five decisions is that they posed a trade-off between cost and well safety.

Well Design. On April 19, one day before the blowout, BP installed the final section of steel tubing in the well. BP had a choice of two primary options: it could lower a full string of "casing" from the top of the wellhead to the bottom of the well, or it could hang a "liner" from the lower end of the casing already in the well and install a "tieback" on top of the liner. The liner-tieback option would have taken extra time and was more expensive, but it would have been safer because it provided more barriers to the flow of gas up the annular space surrounding these steel tubes. A BP plan review prepared in mid-April recommended against the full string of casing because it would create "an open annulus to the wellhead" and make the seal assembly at the wellhead

the "only barrier" to gas flow if the cement job failed. Despite this and other warnings, BP chose the more risky casing option, apparently because the liner option would have cost $7 to $10 million more and taken longer.

Centralizers. When the final string of casing was installed, one key challenge was making sure the casing ran down the center of the well bore. As the American Petroleum Institute's recommended practices explain, if the casing is not centered, "it is difficult, if not impossible, to displace mud effectively from the narrow side of the annulus," resulting in a failed cement job. Halliburton, the contractor hired by BP to cement the well, warned BP that the well could have a "SEVERE gas flow problem" if BP lowered the final string of casing with only six centralizers instead of the 21 recommended by Halliburton. BP rejected Halliburton's advice to use additional centralizers. In an e-mail on April 16, a BP official involved in the decision explained: "it will take 10 hours to install them. ... I do not like this." Later that day, another official recognized the risks of proceeding with insufficient centralizers but commented: "who cares, it's done, end of story, will probably be fine."

Cement Bond Log. BP's mid-April plan review predicted cement failure, stating "Cement simulations indicate it is unlikely to be a successful cement job due to formation breakdown." Despite this warning and Halliburton's prediction of severe gas flow problems, BP did not run a 9- to 12-hour procedure called a cement bond log to assess the integrity of the cement seal. BP had a crew from Schlumberger on the rig on the morning of April 20 for the purpose of running a cement bond log, but they departed after BP told them their services were not needed. An independent expert consulted by the Committee called this decision "horribly negligent."

Mud Circulation. In exploratory operations like the Macondo well, wells are generally filled with weighted mud during the drilling process. The American Petroleum Institute (API) recommends that oil companies fully circulate the drilling mud in the well from the bottom to the top before commencing the cementing process. Circulating the mud in the Macondo well could have taken as long as 12 hours, but it would have allowed workers on the rig to test the mud for gas influxes, to safely remove any pockets of gas, and to eliminate debris and condition the mud so as to prevent contamination of the cement. BP decided to forego this safety step and conduct only a partial circulation of the drilling mud before the cement job.

Lockdown Sleeve. Because BP elected to use just a single string of casing, the Macondo well had just two barriers to gas flow up the annular space around the final string of casing: the cement at the bottom of the well and the seal at the wellhead on the sea floor. The decision to use insufficient centralizers created a significant risk that the cement job would channel and fail, while the decision not to run a cement bond log denied BP the opportunity to assess the status of the cement job. These decisions would appear to make it crucial to ensure the integrity of the seal assembly that was the remaining barrier against an influx of hydrocarbons. Yet, BP did not deploy the casing hanger lockdown sleeve that would have prevented the seal from being blown out from below.

These five questionable decisions by BP are described in more detail below. We ask that you come prepared on Thursday to address the concerns that these decisions raise about BP's actions.

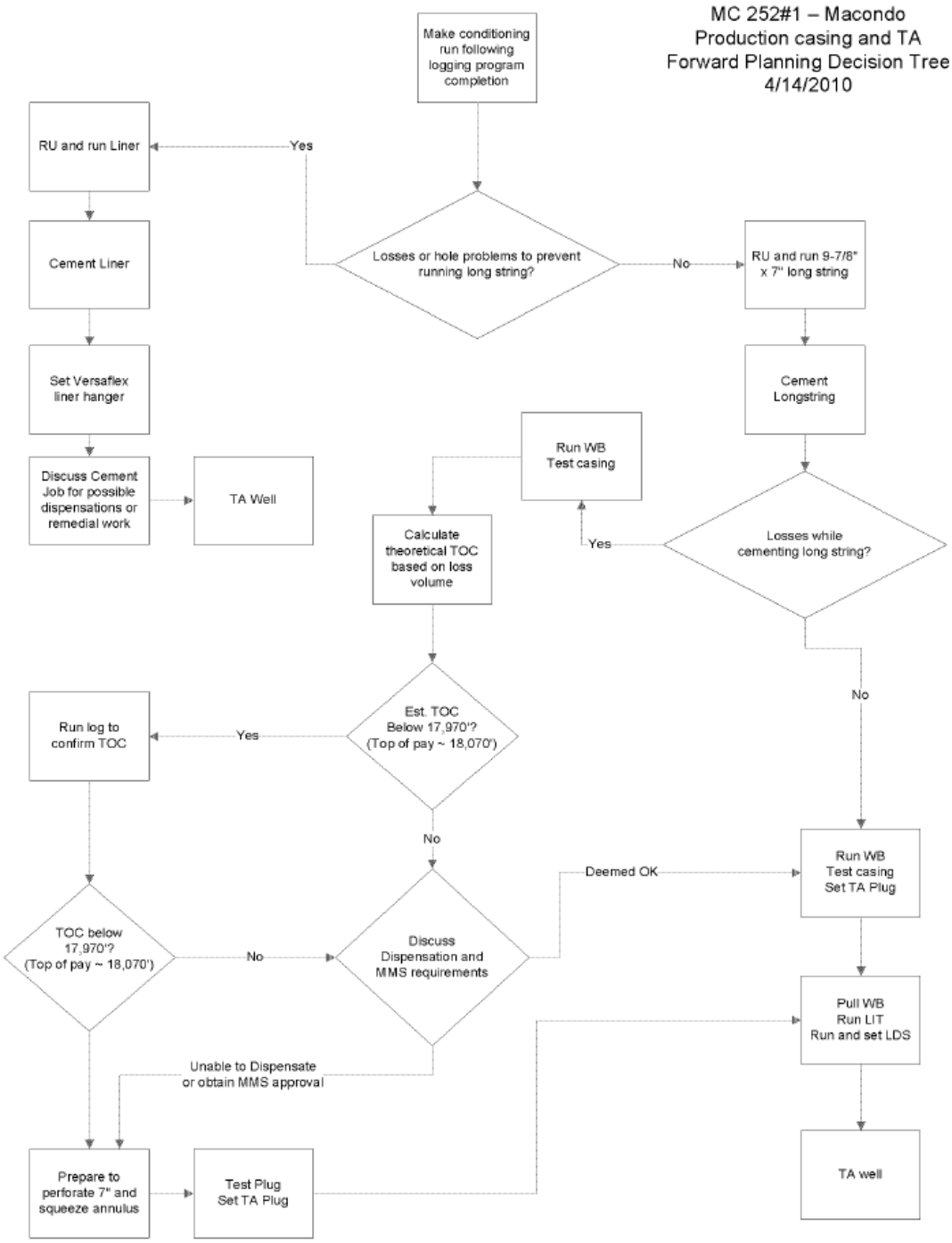
The Committee's investigation into the causes of the blowout and explosion on the Deepwater Horizon rig is continuing. As our investigation proceeds, our understanding of what happened and the mistakes that were made will undoubtedly evolve and change. At this point in the investigation, however, the evidence before the Committee calls into question multiple decisions made by BP. Time after time, it appears that BP made decisions that increased the risk of a blowout to save the company time or expense. If this is what happened,

BP's carelessness and complacency have inflicted a heavy toll on the Gulf, its inhabitants, and the workers on the rig.

During your testimony before the Committee, you will be asked about the issues raised in this letter. This will provide you an opportunity to respond to these concerns and clarify the record. We appreciate your willingness to appear and your cooperation in the Committee's investigation.

Sincerely,
Henry A. Waxman, Chairman, Committee on Energy and Commerce
Bart Stupak, Chairman, Subcommittee on Oversight and Investigations

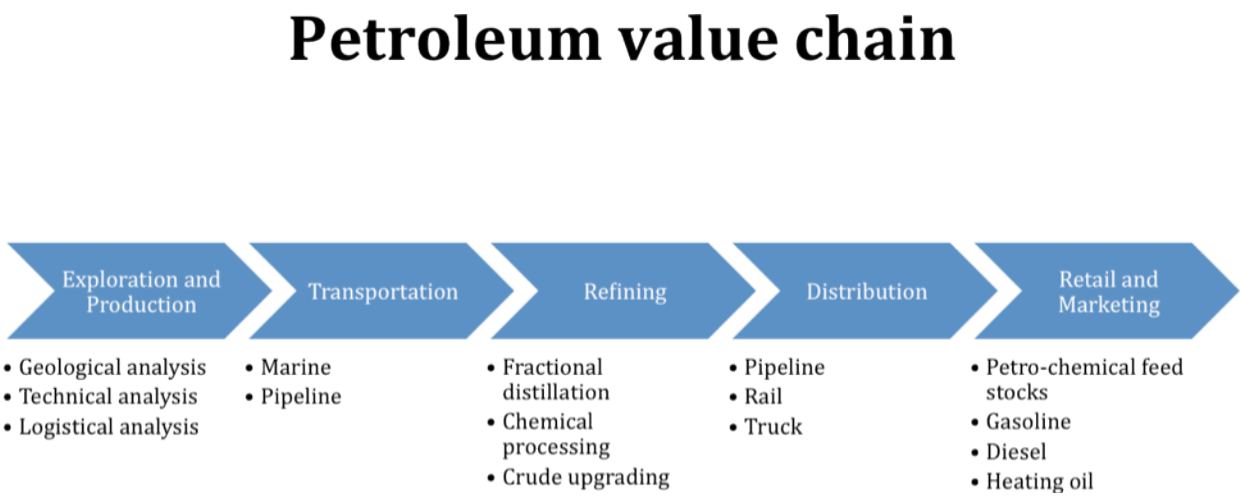
Exhibit 4 BP's Cement Bond Log Decision Tree



Source: Casewriter.

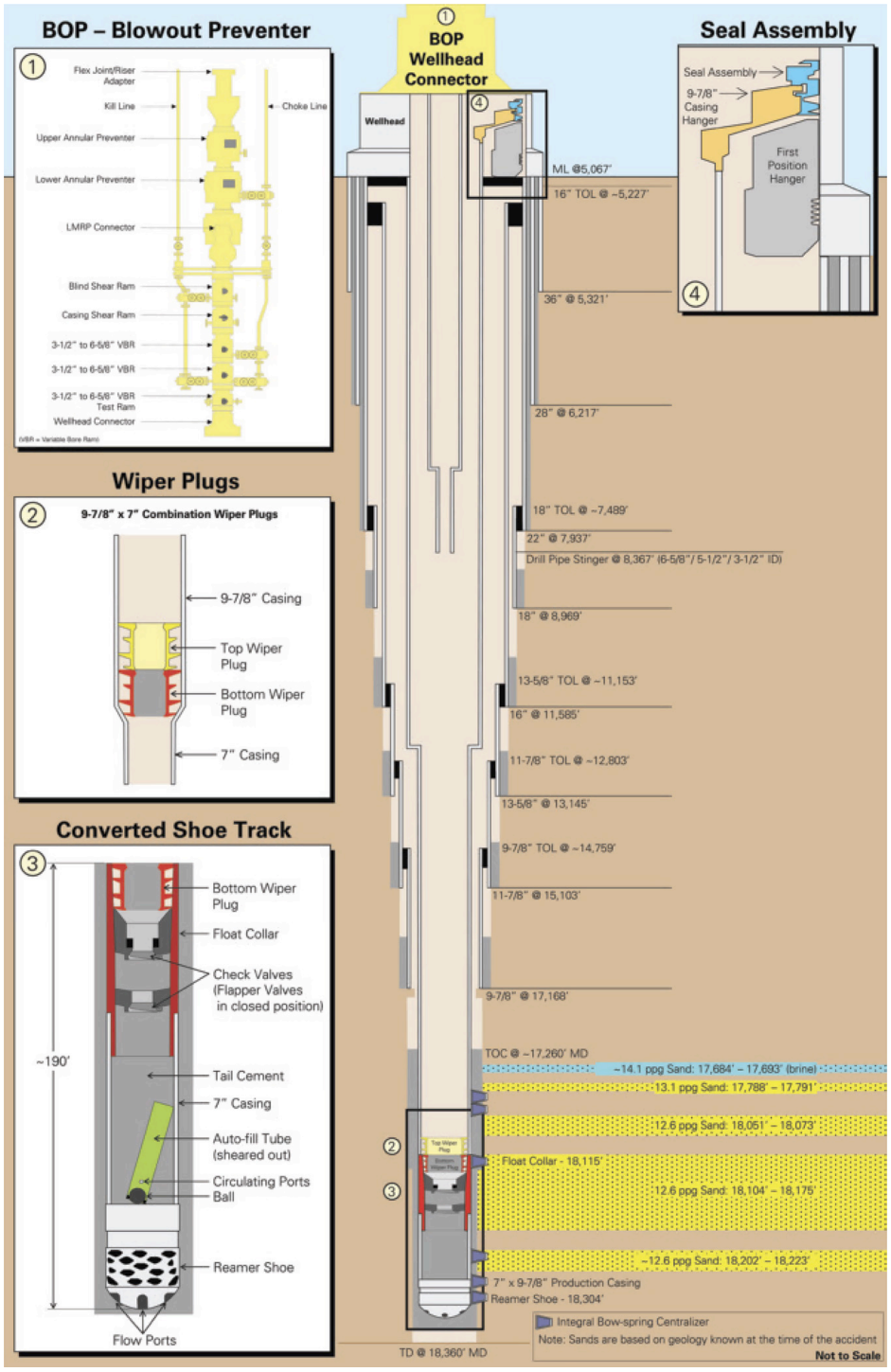
Appendices

Appendix 1 Petroleum Value Chain



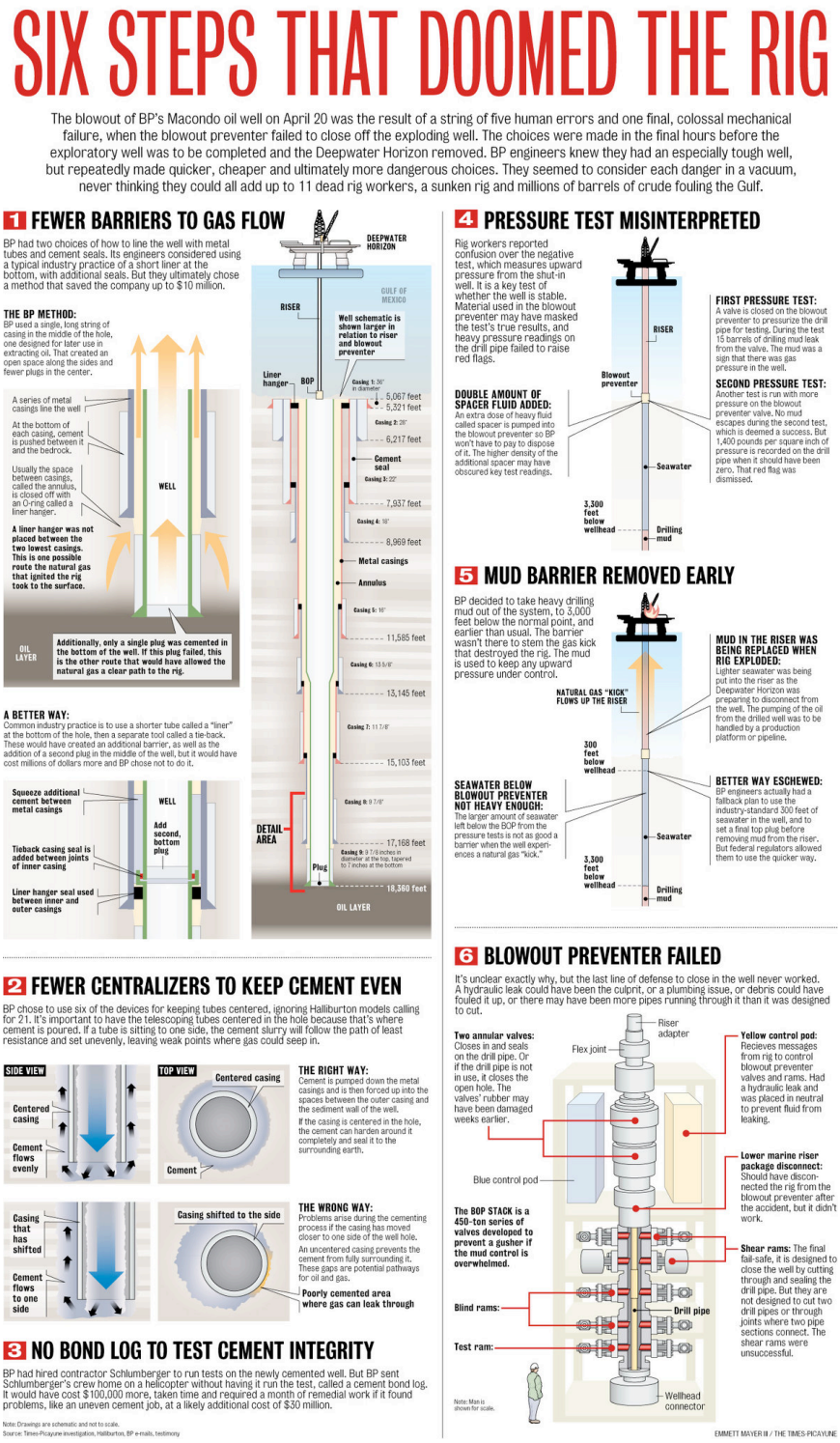
Source: Casewriter.

Appendix 2 Macondo Well Design Diagram with Predicted Problem Sites



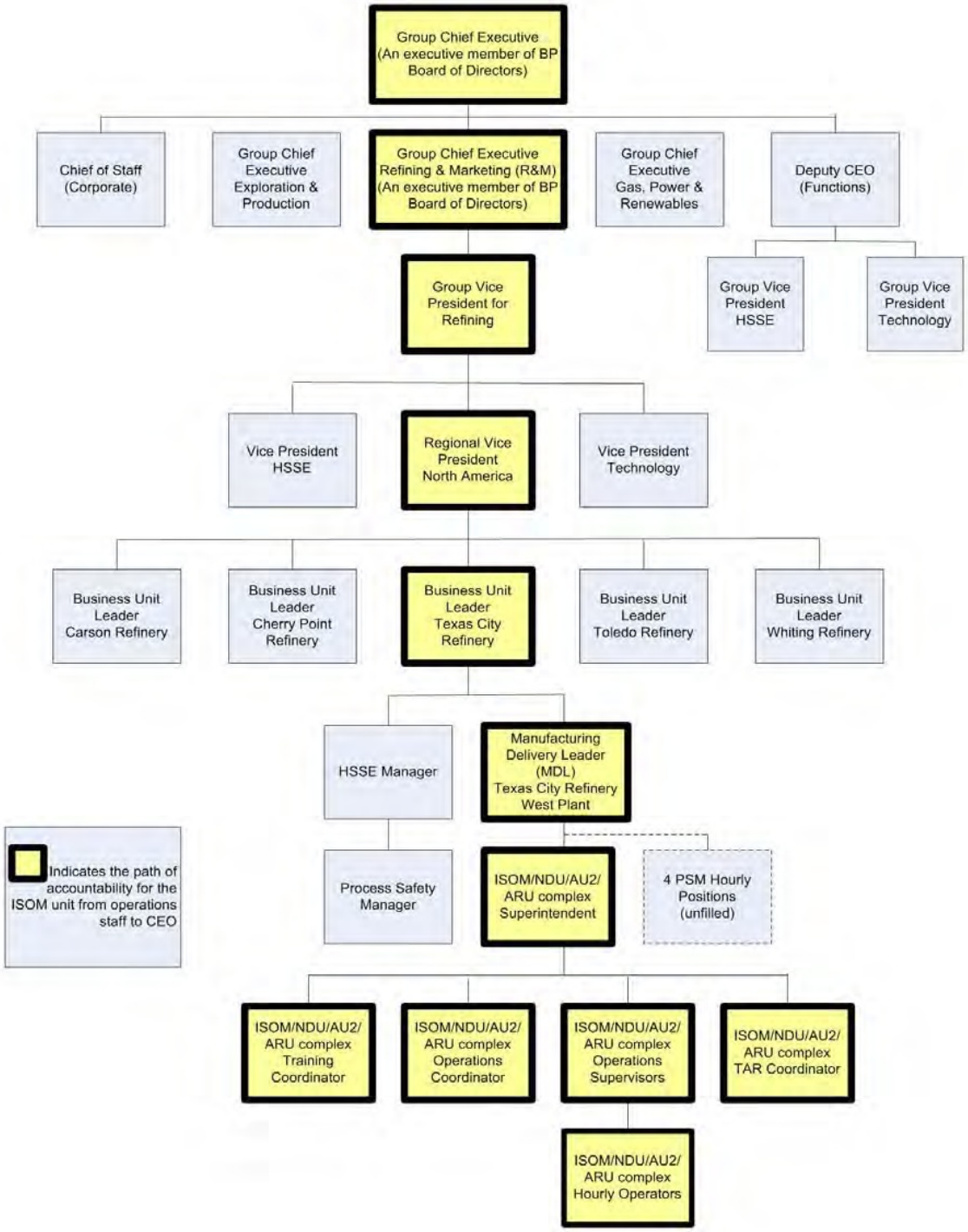
Source: BP. Deepwater Horizon Accident Investigation Report Appendix C. September 8, 2010.

Appendix 3



Source: http://media.nola.com/2010_gulf_oil_spill/photo/six-steps-that-doomed-the-rigjpg-bd73481b6f076ab0.jpg

Appendix 4 BP Organizational Chart 2007



Source: Prepared for the Chemical Safety Board Final Investigation Report for the Texas City Disaster, March 20, 2007.